BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

STATE OF GEORGIA

In Re:

Georgia Power Company's 2022 Application for Approval of its Integrated Resource Plan	)	Docket No. 44160

In Re:

Georgia Power Company's 2022 Application for Approval of its Amended DSM Plan and Certification and Decertification of Certain DSM Programs	)	Docket No. 44161

Hearing Room 110
244 Washington Street
Atlanta, Georgia

Tuesday, June 21, 2022

The above-entitled matter came on for hearing Pursuant to Notice at 9:52 a.m.

PRESENT WERE:
TRICIA PRIDEMORE, Madam Chair
TIM ECHOLS, Vice-Chairman (By Zoom)
FITZ JOHSON, Commissioner
LAUREN "BUBBA" MCDONALD, Commissioner
JASON SHAW, Commissioner

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I N D E X

P R O C E E D I N G S

MADAM CHAIR PRIDEMORE: Okay. Let's call this meeting to order.

This is Docket No. 44160, Docket No. 44161, Georgia Power Company's 2022 application for approval of its integrated resource plan and amended DSM plan and certification and decertification of certain DSM programs.

I have an appearance list before me, if you would indicate that you're here present.

MR. WALSH: Thank you, Madam Chair. Daniel Walsh and Preston Thomas on behalf of the Public Interest Advocacy Staff. Thank you.

MADAM CHAIR PRIDEMORE: Mr. Walsh.

MR. HEWITSON: Good morning. Steve Hewitson, Brandon Marzo, and Allison Pryor on behalf of Georgia Power Company.

MADAM CHAIR PRIDEMORE: Mr. Hewitson.

Americans for Affordable Clean Energy.

MR. GALLOWAY: Newton Galloway and Terri Lyndall on behalf of ACA.

MADAM CHAIR PRIDEMORE: Commercial Group.

MR. JENKINS: Good morning. Alan Jenkins.

MADAM CHAIR PRIDEMORE: Good morning, Mr. Jenkins.

Concerned Ratepayers for Georgia.

MR. PRENOVITZ: Steve Prenovitz, Ben Stockton, Concerned Ratepayers of Georgia.

MADAM CHAIR PRIDEMORE: Cypress Creek Renewables.

(No response.)

MADAM CHAIR PRIDEMORE: Okay. Georgia Association of Manufacturers.

MR. JONES: I'm here. Clay Jones.

MADAM CHAIR PRIDEMORE: Georgia Center for Energy Solutions.

(No response.)

MADAM CHAIR PRIDEMORE: Georgia Coalition of Local Governments.

MS. BROWN: Good morning. Alicia Brown.

MADAM CHAIR PRIDEMORE: Georgia Interfaith Power & Light and Partnership for Southern Equity.

MS. KYSOR: Good morning. Jill Kysor and Munashe Magarira for Georgia Interfaith Power & Light and Partnership for Southern Equity.

MADAM CHAIR PRIDEMORE: Georgia Large Scale Solar Association and Advanced Power Alliance.

MR. CARVER: Brad Carver.

MADAM CHAIR PRIDEMORE: Georgia Solar Energy Industries Association, Solar Energy Association, and Vote Solar.

MR. THOMASSON: Scott Thomasson.

MADAM CHAIR PRIDEMORE: Georgia Solar Energy Association.

(No response.)

MADAM CHAIR PRIDEMORE: Georgia Watch.

MS. COYLE: Good morning. Liz Coyle for Georgia Watch.

MADAM CHAIR PRIDEMORE: Interstate Gas Supply.

MR. CARVER: Brad Carver and Adam Wise. Thank you.

MADAM CHAIR PRIDEMORE: Resource Supply Management.

(No response.)

MADAM CHAIR PRIDEMORE: Restore Chattooga Gorge Coalition.

MR. PENDERGRAST: Craig Pendergrast here and Steven Jones, who will be here later.

MADAM CHAIR PRIDEMORE: Sierra Club.

MS. ARIZA: Isabella Ariza and Zach Fabish.

MADAM CHAIR PRIDEMORE: Southern Alliance For Clean Energy and Southface Energy Institute.

MR. BAKER: Good morning. Robert Baker for SACE and Southface.

MADAM CHAIR PRIDEMORE: Good morning,

Mr. Baker.

Southern Renewable Energy Association.

MR. MAHAN: Good morning, Commission. Simon Mahan for the Southern Renewable Energy.

MADAM CHAIR PRIDEMORE: Okay. Very good.

All right. Anybody I missed?

(No response.)

MADAM CHAIR PRIDEMORE: Okay. That's good.

Are there any housekeeping matters to come before us before we get started?

(No response.)

MADAM CHAIR PRIDEMORE: None from the staff.

Okay. I want to remind you. I'm going to give everybody an opportunity to question the panel. If your question has already been asked, please refer to the answer that was provided to another intervenor. I just want to keep it moving.

We are familiar with the fact that today is a rebuttal hearing so we don't want to be redundant. We want to keep information clear and concise.

Okay. Go ahead, Mr. Hewiston, and swear in your witnesses.

MR. HEWITSON: Thank you, Madam Chair.

Again, Steve Hewitson on behalf of Georgia Power Company. At this time Georgia Power Company calls the panel of Mr. Grubb, Mr. Mallard, Mr. Robinson, and Mr. Weathers, as well as Mr. Aaron Mitchell.

Gentlemen, would you please raise your right hands.

Thereupon,

JEFFREY R. GRUBB,
A. WILSON MALLARD,
MICHAEL B. ROBINSON,
JEFFREY B. WEATHERS,
AARON D. MITCHELL,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. HEWITSON:

Q Gentlemen, you all previously testified in this IRP docket; is that correct?

A (Witness Grubb) Yes.

A (Witness Mallard) Yes.

Q Mr. Grubb, would you once again please state your full name, your employer, and your responsibilities for the record.

A (Witness Grubb) Yes. Good morning, Commissioners. My name is Jeffrey R. Grubb. I'm the Director of Resource Policy and Planning for the Georgia Power Company where I'm honored to be able to lead the group that works on generation planning for the power company, including the development of the integrated resource plan.

Q Mr. Mallard, would you do the same.

A (Witness Mallard) Good morning. Andrew Wilson Mallard. I'm the Director of Renewable Development for Georgia Power. And I lead the department responsible for all renewable procurements for Georgia Power Company.

Q And Mr. Robinson.

A (Witness Robinson) Good morning. Mike Robinson. I'm Vice-President of Planning, Operations, and Policy for Georgia Power Company. And I lead the team that is responsible for the planning and operation of the transmission and distribution grid for the state of Georgia.

Q Okay. Mr. Weathers, would you, please.

A (Witness Weathers) Good morning, Commissioners. My name is Jeffrey Brian Weathers. I'm the Manager of Resource Planning for Southern Company Services. And I support Georgia Power and our other retail operating companies in their resource planning activities.

Q And Mr. Mitchell.

A (Witness Mitchell) Good morning, Commissioners. My name is Aaron Mitchell. I'm Vice-President of Environmental Affairs for Georgia Power. I lead the team responsible for environmental compliance, environmental laboratory and services, as well as oversight and execution of our coal combustion residuals and ash pond program.

Q Thank you, gentlemen.

Mr. Grubb, on June 8th of this year, did you prefile or cause to be prefiled 61 pages of rebuttal testimony in question-and-answer format in this docket, Docket No. 44160?

A (Witness Grubb) Yes.

Q Are there any corrections you need to make to your prefiled testimony?

A (Witness Grubb) Yes. On page 47, line 4, the phrase "failing to exceed" should be deleted and replaced with the word "exceed."

And then on page 53, the bottom row in table 2, in the annual additional sum column, the dollar figure should read 14,435,055.

Q Subject to those corrections, if I were to ask you the same questions today under oath, would your answers be the same as set forth in your prefiled testimony?

A (Witness Grubb) Yes, they would.

Q Thank you.

Mr. Mitchell, on June 8th of this year, did you prefile or cause to be prefiled 16 pages of rebuttal testimony in question-and-answer format in this case?

A (Witness Mitchell) Yes.

Q Are there any corrections you need to make to your prefiled testimony?

A (Witness Mitchell) Yes. I have one. On page 2, line 2, the word "director" should be replaced with "vice-president."

Q Okay. And subject to that correction, if I were to ask you the same questions today under oath, would your answers be the same as they were in your prefiled testimony?

A (Witness Mitchell) Yes.

MR. HEWITSON: Madam Chair, the court reporter has been provided a copy of the prefiled direct [sic] testimonies and I now ask that the direct testimonies of this panel and Mr. Mitchell be copied into the record as if given heretoday.

MADAM CHAIR PRIDEMORE: So moved.

(Whereupon, the prefiled direct testimonies of Mr. Grubb, Mr. Mallard, Mr. Robinson, Mr. Weathers and Mr. Mitchell follows:)

STATE OF GEORGIA

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:

Georgia Power Company's	**)**	**Docket No. 44160**
2022 Integrated Resource Plan	**)**	

REBUTTAL TESTIMONY OF

JEFFREY R. GRUBB, A. WILSON MALLARD, MICHAEL B. ROBINSON,

AND JEFFREY B. WEATHERS

June 8, 2022

REBUTTAL TESTIMONY OF
JEFFREY R. GRUBB, A. WILSON MALLARD, MICHAEL B. ROBINSON,
AND JEFFREY B. WEATHERS

IN SUPPORT OF GEORGIA POWER COMPANY'S
2022 INTEGRATED RESOURCE PLAN
GPSC DOCKET NO. 44160

I. INTRODUCTION

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

A. My name is Jeffrey R. Grubb. I am the Director of Resource Policy and Planning for Georgia Power Company ("Georgia Power" or the "Company"). My business address is 241 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308.

A. My name is Andrew Wilson Mallard. I am the Director of Renewable Development for Georgia Power. My business address is 241 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308.

A. My name is Michael B. Robinson. I am the Vice President for Planning, Operations, and Policy for Georgia Power. My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

A. My name is Jeffrey Bryan Weathers. I am the Manager of Resource Planning for Southern Company Services, Inc. ("SCS"). My business address is 600 North 18th Street, Birmingham, Alabama 35203.

Q. DID YOU PREVIOUSLY PRESENT DIRECT TESTIMONY ON BEHALF OF GEORGIA POWER IN THESE PROCEEDINGS?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of our testimony is to respond to the testimony of the Georgia Public Service Commission ("Commission") Public Interest Advocacy Staff ("Staff") and various intervenors filed in Docket No. 44160. Due to the number of Parties filing testimony in this case and the limited time available to file rebuttal, our testimony focuses on several key issues without attempting to address every issue raised in Staff or intervenor testimony. However, the fact that the Company may not respond to a particular position of Staff or an intervenor should not be construed as acceptance of such position.

Q. PLEASE SUMMARIZE THE TESTIMONY OF THE PANEL.

A. The Company's 2022 Integrated Resource Plan ("IRP") reflects the Company's continued disciplined approach to ensuring that all of its customers receive clean, safe, reliable and affordable electric service both now and in the future. Consistent with every IRP since 1992, the Company's Reserve Margin Study and proposed Target Reserve Margins have been evaluated and based on both reliability and economics. This approach has and will continue to enable the Company to plan for reliable and cost-effective service for customers. The Commission should adopt the Company's proposed 26% Winter Target Reserve Margin to enable continued reliable operations at an economically optimal cost along with coordinated planning with the other Southern Company Operating Companies, which affords many benefits to Georgia Power's customers.

The Company's Unit Retirement Study supports the retirements of Plant Wansley Units 1-2 and 5A, Plant Boulevard Unit 1, Plant Bowen Units 1-2, Plant Scherer Unit 3, and Plant Gaston Units 1-4 and A. Commission Staff agreed with all of the requested retirements except for Plant Bowen Units 1-2, which it identified as a close call. However, the Company's economic analysis demonstrates that the continued operation of Plant Bowen Units 1-2 is not economic or in the best interest of customers. Therefore, this Commission should approve the requested retirements and decertifications and approve the continued operation of the remainder of the Company's generating fleet.

The Commission should approve the Company's requested certification of the six Power Purchase Agreements ("PPAs") executed as a result of Georgia Power's 2022-2028 Capacity Request for Proposals ("RFP"). These resources offer competitive pricing, approximately 25-35% lower than prices the Company pays for existing natural gas PPAs, and provide significant value with firm natural gas transportation. These resources were selected by the Company after a thorough evaluation, as overseen and approved by Commission Staff and the Independent Evaluator ("IE"), through a fair and transparent Capacity RFP conducted in accordance with the Commission's RFP rules. The Commission should also approve the Company's requested additional sum for the Capacity RFP PPAs as a reasonable incentive to procure these resources.

The Company must continue its investment in its hydro fleet to ensure these low-cost, zero-carbon resources can continue to provide valuable service to customers. As such, the Commission should approve the Company's plans to refurbish, replace, and upgrade the units at Plant Burton, Plant North Highlands, and Plant Sinclair. The improvements for Plant Tugalo were approved as part of the 2019 IRP due to the benefits associated with its continued reliable operation. The Commission should reject intervenor requests seeking to overturn its prior decision and remove the Plant Tugalo dam. Such requests ignore the benefits associated with Plant Tugalo's continued operation and the adverse impact removal of the dam would have on operations at neighboring Plants Yonah, Tallulah, Terrora, Nacoochee, and Burton.

The Commission should approve the Tall Wind Demonstration and the Integrated Hydrogen Microgrid projects as proposed by Georgia Power. These projects will be located in Georgia and will directly benefit Georgia Power's customers. Therefore, it is appropriate that the costs of these projects also be allocated to Georgia Power's customers.

In light of the increasing strain on the transmission system due to the gap between generation in south Georgia and load in north Georgia, which will be exacerbated by the eventual retirement of Plant Bowen, the Commission should approve the Company's North Georgia Reliability and Resilience Action Plan. The Company's first utility scale RFP must be limited to projects located in north Georgia to provide the Company sufficient time to continue to build out its transmission system while adding renewable resources to help relieve the strain on the transmission system. Alternative proposals suggested by Staff and intervenors are impractical, difficult or impossible to implement, and do not adequately recognize the physical infrastructure limitations driving the need for the North Georgia Reliability and Resilience Action Plan.

With the continued expansion of renewable resources, energy storage systems ("ESS") are increasingly important to the reliability of the System. The Commission should approve the Company's proposal to own and operate 1,000 megawatts ("MW") of ESS by 2030, with the McGrau Ford Battery Facility as the first project approved to meet this goal.

The Commission should approve the Company's requested 2,300 MW of renewable resources as a continuation of Georgia Power's measured and practical approach to adding renewable resources. The Company's transition to the best cost evaluation methodology will provide the necessary flexibility in forming the best cost portfolio of resources that is responsive to Georgia Power's renewable RFPs. Further, the Company has proposed several improvements to the distributed generation ("DG") interconnection process in this IRP, and a requirement for further review by Commission Staff is not necessary.

The Renewable Cost Benefit ("RCB") Framework should be revised to remove the Generation Remix component and substitute the Integration Cost component for the Support Capacity component, among other modifications as proposed by the Company. The Company agrees that for IRP-approved procurements for which Renewable Energy Credits ("RECs") are conveyed to the Company, a REC component could be included in the RCB Framework. As revised, this RCB Framework should be approved for use in the evaluation of renewable RFPs, including those proposed in this IRP.

The Company's request for reclassification of the net book value and amortization of the units proposed to be retired and decertified can be appropriately decided in this case. The Company's recommendations are consistent with the regulatory treatment of similarly situated units in prior cases. Therefore, the Commission should approve the Company's request for such reclassification.

II. RELIABILITY

Q. WHAT ARE THE COMPANY'S RECOMMENDED SUMMER AND WINTER TARGET RESERVE MARGINS?

A. The Company plans to maintain the current 16.25% long-term Summer Target Reserve Margin and the 26% long-term Winter Target Reserve Margin for the System. For the short term (2022-2024), the Company plans to use the System targets of 15.75% for summer and 25.5% for winter.

Q. WHY IS THE RESERVE MARGIN STUDY CONDUCTED AT A SYSTEM LEVEL AND WHY MUST EACH OPERATING COMPANY PLAN TO THE SAME TARGET?

A. The Reserve Margin Study is conducted at the System level because the entire System is dispatched as a pool, providing numerous benefits to Georgia Power customers. This pooling arrangement requires a coordinated planning process. Resource planning and analysis for the Southern Company System is done at a system level to evaluate the System's ability to meet the Resource Adequacy needs of the pool as a whole. To preserve the benefits of the coordinated planning approach, which has benefited the Company and its customers for many years, the Southern Operating Companies must continue to plan to the same Target Reserve

Margin. Many of the benefits of coordinated system planning would be eroded if each Operating Company planned to a separate reserve margin target.

Q. PLEASE DESCRIBE STAFF'S CRITIQUE OF THE COMPANY'S PROPOSED 26% WINTER TARGET RESERVE MARGIN.

A. Staff asserted that the load forecast error ("LFE") component utilized in the Company's Reserve Margin Study is incorrect because it is not reflective of the Company's historical load forecast error. Staff recommended use of 24.5% as the Winter Target Reserve Margin after modification of the LFE distribution.

Q. HOW DID STAFF ADJUST THE LFE COMPONENT TO CALCULATE ITS PROPOSED 24.5% LONG-TERM WINTER TARGET RESERVE MARGIN?

A. Commission Staff compared the Company's actual weather normal loads to Georgia Power's projected load forecast for years 2000 through 2017 and observed that the Company over-forecasted its load in every year during that period. Consequently, Staff created a proxy LFE distribution that reflects a 0% probability of under-forecasting future load. Because the Company's LFE distribution allowed for both over-forecast and under-forecast situations, Staff's proxy LFE resulted in a lower Winter Target Reserve Margin than the 26% recommended by the Company.

Q. IS IT APPROPRIATE TO ONLY CONSIDER OVER-FORECAST SITUATIONS FOR FUTURE LOAD?

A. No. It is inappropriate and unwise to only consider over-forecast situations for future load. While the Company and the industry have over-forecasted peak demand in recent years, that does not mean that peak demand will always be over-forecasted in future years, just as it has not always been over-forecasted in the past. A number of factors, such as increased net migration, extreme weather, and large customer choice loads, can increase actual loads when compared to the forecast.

Failing to consider the possibility that a peak demand could exceed the current forecast would set a dangerous precedent. It would effectively mean that, in every one of the 754,000 Reserve Margin Study simulations that are used to determine the Target Reserve Margin, the Company is considering zero instances where load might exceed the official peak demand forecast. The Reserve Margin Study should determine the planning reserve margin that considers meaningful risks to future power supply and demand. It would be inappropriate to plan for a reserve margin based on assumptions that the Company will never have actual loads above forecast. Therefore, the Staff's proposed adjustment to the Company's 26% System Winter Target Reserve Margin is also inappropriate.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED A TARGET RESERVE MARGIN BASED ON A STUDY EVALUATING BOTH RELIABILITY AND ECONOMICS?

A. Yes. Beginning with the first IRP in 1992 and in each IRP thereafter, the Company's Reserve Margin Study has evaluated both the economic and reliability aspects of the Target Reserve Margin. In addition, each approved Target Reserve Margin has similarly been based on both reliability and economics.

Q. SOME INTERVENORS RECOMMENDED THAT THE COMPANY UTILIZE A RELIABILITY METRIC ONLY AND NOT CONSIDER ECONOMICS IN ITS TARGET RESERVE MARGIN CALCULATION. IS THIS APPROPRIATE?

A. No. The Company considers both reliability and economics in determining its recommended Target Reserve Margins, which is appropriate and beneficial to customers. The Company considers the one event in ten years Loss of Load Expectation ("1:10 LOLE") as a minimum threshold for the Target Reserve Margin. However, when additional reliability can be achieved at lower cost, it is appropriate to plan to the economic optimal reserve margin ("EORM") rather than simply the minimum needed for reliability purposes. In the Reserve Margin Study, the total cost to customers of the 26% Winter Target Reserve Margin is lower than the total cost to customers at the 20% 1:10 LOLE level by approximately $35 million per year because the additional capacity cost is outweighed by production cost savings and lower costs of unserved energy. This benefits customers both in terms of higher reliability and lower total costs. Staff agrees with the Company's approach to use the EORM in setting the Target Reserve Margin so that it establishes an appropriate level of reliability and minimizes the cost to customers.

Q. STAFF AND THE GEORGIA ASSOCIATION OF MANUFACTURERS ("GAM") EACH PROVIDED A TABLE COMPARING THE TARGET RESERVE MARGINS OF SELECT UTILITIES OF NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION ("NERC") ASSESSMENT AREAS IN THEIR TESTIMONY. ARE ALL OF THOSE RESERVE MARGINS DIRECTLY COMPARABLE TO THE COMPANY'S TARGET RESERVE MARGINS?

A. No. The NERC Reference Reserve Margins are not necessarily reflective of reliability assessments in every region. NERC states in the report, "[i]f a Reference Reserve Margin is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydro systems."[1] Notably, the Southern Company System has a Target Reserve Margin of 26% in the winter and 16.25% in the summer, and NERC's Reference Reserve Margin for SERC-Southeast is 15%. Unlike the Company's Reserve Margin Study, the reserve margins listed for other utilities, Regional Transmission Organizations ("RTOs"), and regions in Staff and GAM's tables are not based on detailed reliability studies for the Company's service territory.

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[1] 2022 Summer Reliability Assessment, NERC (May 2022) at 36, available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf. (hereinafter NERC 2022 SRA).

Q. ARE SOME OF THE UTILITIES INCLUDED IN STAFF AND GAM'S TABLES EXPERIENCING RELIABILITY ISSUES?

A. Yes. Some of these utilities have experienced winter reliability events in the recent past. In addition, several have issued conservation notices for the upcoming summer indicating the reserves may not be sufficient to adequately meet customer demand in the summer months. In recent years, several of these regions have instituted rolling black or brown outs to address operational issues due to insufficient reserves. Finally, some regions are revising planning processes to address seasonal planning considerations.[2] While seasonal reliability events are not solely a function of actual reserve margins, establishing appropriate seasonal Target Reserve Margins provides System operators with additional dispatch options to better mitigate seasonal reliability concerns.

Q. IS GEORGIA POWER ISOLATED FROM RELIABILITY ISSUES EXPERIENCED IN OTHER PARTS OF THE COUNTRY?

A. No. Extreme weather can cause reliability events in Georgia Power's service territory, even with the Company's recommended Target Reserve Margins. Given the learnings from recent events and the continued expectation of seasonal

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[2] *See* (1) MISO's Filing to Include Seasonal and Accreditation requirements for the MISO Resource Adequacy Construct (Nov. 30, 2021), available at https://cdn.misoenergy.org/2021-11-30_RAN%20Seasonal%20Construct%20and%20Availability%20based%20accreditation608310.pdf (providing details on MISO's plan to establish seasonal resource adequacy retirements); (2) A Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm: Analysis and Recommendations, Southwest Power Pool (July 19, 2021) available at https://www.spp.org/documents/65037/comprehensive%20review%20of%20spp's%20response%20to%20the%20feb.%202021%20winter%20storm%202021%2007%2019.pdf (providing SPP's recommendation to improve or develop policies addressing seasonal resource adequacy during normal and extreme conditions); and (3) Ten Year Power Plant Site Plan 2022-2031, Florida Power and Light, Florida Public Service Commission, Docket No. 20220000-OT (April 2022) available at http://www.psc.state.fl.us/Files/PDF/Utilities/Electricgas/TenYearSitePlans/2022/Florida%20Power%20and%20Light%20Company.pdf (providing information about a new winter peak demand used for planning purposes that is 40% higher than their normal winter peak demand).

reliability concerns in some regions,[3] the Company does not recommend reducing the Target Reserve Margin to a minimum level of reliability, but instead recommends maintaining the current Winter and Summer Target Reserve Margins recommended in the 2021 Reserve Margin Study.

III. SCENARIO DESIGN & EXPANSION PLANNING

Q. STAFF AND INTERVENORS EXPRESSED CONCERNS WITH THE COMPANY'S UTILIZATION OF DIFFERENT MODELS TO SUPPORT ITS PORTFOLIO OF STUDIES AND ASSOCIATED PROPOSALS IN THE 2022 IRP. PLEASE EXPLAIN WHY THE COMPANY TAKES THIS APPROACH.

A. The Company begins its resource planning approach more than a year prior to filing its IRP. Each study performed in support of the IRP is sequenced because, in many cases, the output of one study is the input for another one. For example, the Company conducted the renewable expansion plan analysis to guide its renewable request in the 2022 IRP and included this plan as an input into all planning scenarios in the final IRP cases. The resource mix model could then optimize around the renewable expansion plan. In addition, the Company regularly uses the best and most current information available as the resource planning process proceeds throughout the year. Therefore, it is possible and expected that some inputs into an early run model or study may not be used for a later run study in the process. Further, each model may require different types of data. Some models use weather-normal data while others use stochastic analysis to randomize data, just as some studies are conducted using hourly versus intra-hourly data.

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[3] *See* NERC 2022 SRA; 2021-2022 Winter Reliability Assessment, NERC (Nov. 2021) available at (https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2021.pdf.

Q. HOW DID STAFF UTILIZE PLANNING MODELS TO REACH ITS RECOMMENDATIONS ON THE FLEET TRANSITION?

A. Staff utilized AURORA to evaluate coal retirements, proposed Capacity RFP PPAs, and additions of future generic resource options. This evaluation was conducted in two stages. In the first stage, all pertinent decisions the Company proposed were modeled as selectable options that could be optimized in AURORA. Staff's studies were performed for each fuel and carbon scenario for a study period through 2039. In the second stage, Staff analyzed potential action plans with near-term decisions, such as the retirement date of Plant Bowen Units 1-2 or the amount of solar to procure through 2029, locked down for analysis across each fuel and carbon scenario.

Q. DESPITE RUNNING INDEPENDENT ANALYSES, DID THE COMPANY AND STAFF REACH SIMILAR CONCLUSIONS RELATED TO THE FLEET TRANSITION?

A. Yes. Staff states, "[w]ith the exception of Bowen 1-2, and with regard to the coal retirement units and PPA acquisitions, Staff's and the Company's Action Plans match completely." (Tr. 120.) Staff's analysis also led to agreement with the Company's proposed procurement of 2,300 MW of solar resources by the end of 2029.

Q. IS IT APPROPRIATE FOR THE COMPANY TO CONSIDER POTENTIAL CARBON LEGISLATION IN ITS PLANNING SCENARIOS?

A. Yes. Carbon pressure and the potential for federal carbon legislation and regulation continues to increase notwithstanding changes in administration. As such, and as noted by many intervenors, carbon pressure is a risk that should be considered by the Company. In fact, it would be riskier for the Company not to consider potential future carbon legislation in its scenarios, given the long-term nature of the decisions being made. The Company created and evaluated 11 scenarios in the development of its IRP. Notably, the Company did not rely on a single scenario or carbon view in making decisions. Rather, the Company considered the impact of several different carbon and natural gas futures on its planning decisions.

Q. WHAT IS THE PURPOSE OF THE RESOURCE MIX STUDY AND THE GENERIC EXPANSION PLANS?

A. The Company's expansion planning analysis determines the optimal mix of resources that satisfy future capacity and energy demands in an economic and reliable manner. In this step of the planning process, demand-side resources are integrated with supply-side resources to provide a roadmap that informs long-term resource planning decisions. Significantly, generic expansion plans do not represent a resource planning decision by the Company but rather are indicative of what may be an optimal mix of resources within various scenarios. Actual resource deployments occur through specific requests to the Commission as a result of RFPs or other requests in the IRP.

The results of generic expansion plan modeling are combined with the existing fleet of resources as inputs into more detailed production cost modeling to produce hourly avoided energy costs for each scenario. Using this information, the Company then performs resource-specific economic evaluations for both demand-side and supply-side options.

IV. SUPPLY-SIDE STRATEGY

Fleet Transition

Q. PLEASE DESCRIBE GEORGIA POWER'S PROPOSED PLAN AS IT RELATES TO COAL RESOURCES.

A. As set forth in the 2022 IRP, Georgia Power's current supply-side plan provides customers with substantial reliability and economic benefits while establishing a strategic plan for the incremental retirement of the Company's remaining coal resources and corresponding transition to resources that will deliver clean, safe, reliable, and affordable energy for decades to come. The plan includes a combination of unit retirements to take place in the current calendar year, retirements to take place by the end of 2027 and 2028, and the continued operation of some units. As shown in Table 1, the Company is requesting decertification of many of its units (collectively, the "Retirement Units"), for a total decertification amount of 3,520 MW (winter rating) of Georgia Power-owned coal generating capacity. The Company will continue to operate Plant Bowen Units 3-4 and Plant Scherer Units 1-2, all with appropriate Effluent Limitations Guidelines ("ELG") controls, beyond 2028 with plans to retire Plant Bowen Units 3-4 no later than December 31, 2035. The Company will work with its co-owners as it continues to evaluate the future operation of Plant Scherer Units 1-2.

Table 1: Coal Units Proposed for Decertification

Resource	Georgia Power-Owned Winter Capacity (MW)	Retirement Date
Plant Wansley Units 1-2	933	8/31/2022
Plant Bowen Units 1-2	1,432	12/31/2027
Plant Gaston Units 1-4	510	12/31/2028
Plant Scherer Unit 3	645	12/31/2028

Q. WHAT FACTORS DID THE COMPANY CONSIDER IN DECIDING WHETHER TO RETIRE THE COAL UNITS IN THE 2022 IRP?

A. In developing its recommendation to retire the units, the Company considered the economic benefits for customers, future potential environmental costs, and the beneficial replacement generation resulting from the 2022-2028 Capacity RFP. The timing of the retirements proposed in the 2022 IRP considers both reliability and the compliance requirements and deadlines of the ELG rule. The Company also considered the impact that such retirements will have on the plant employees and the communities in which the plants are located.

Q. PLEASE EXPLAIN HOW THE COMPANY ANALYZED THE RETIREMENT DECISION.

A. As in every IRP, the Company evaluates whether its current pool of resources is best suited to continue to serve customers economically and reliably through the economic analysis conducted as part of the Unit Retirement Study contained in Technical Appendix Volume 2 in the 2022 IRP. The results of the analysis indicate that the long-term operation of the Retirement Units is no longer in the best economic interests of customers. The Company's coal resources lack sufficient economic and flexibility attributes to remain competitive within an electric system with large renewable penetration and in a future with continued environmental cost pressures, including carbon.

The economic conditions for coal units continue to deteriorate such that continued operation of the Retirement Units is uneconomical and not in the best interests of customers. The economics are challenged by the combination of forecasted low long-term natural gas prices, modest load growth, continued environmental risk and costs, cost-effective replacement generation procured through the 2022-2028 Capacity RFP, as well as the combination of limited flexibility of the coal units and substantial renewable penetration.

Q. WHAT FUTURE POTENTIAL ENVIRONMENTAL COST RISKS HAS THE COMPANY IDENTIFIED FOR COAL UNITS?

A. As described in the Environmental Compliance Strategy contained in Technical Appendix Volume 2 of the 2022 IRP, potential risks include carbon costs from future legislation or regulation and cost pressures from other future environmental requirements. As indicated by the Unit Retirement Study, in many scenarios with positive values, the benefits for customers are marginal at best. In the scenarios with carbon pricing, which can be used to indicate a range of potential impacts of future environmental pressures on coal units, the economics decline even further and expose customers to costs to be incurred on units which provide no net benefit.

Q. HOW DO ISSUES WITH COAL UNIT FLEXIBILITY IMPACT ECONOMICS?

A. Coal units lack the necessary flexibility characteristics to efficiently respond to large changes in the generating output of renewable resources. For example, as solar penetration increases, daytime marginal energy costs will be depressed, potentially as low as $0/MWh in some hours, because of the abundance of solar energy. Conversely, marginal energy costs may increase at night when solar is not producing. Due to the wear and tear on equipment and boiler operational characteristics, coal units run more efficiently by staying online for several days at a time and thus typically do not start and stop daily, thereby creating economic inefficiencies with substantial intermittent resources. In contrast, more flexible units like gas units and energy storage systems can often turn on and off daily, increasing their advantage over coal units.

Q. HOW DID THE COMPANY ARRIVE AT THE DECISION FOR THE REQUESTED RETIREMENT DATES?

The economic pressures and potential risks facing the Company's coal resources necessitate the development of a strategic transition plan for these resources. The Company's transition plan considers the ELG Reconsideration Rule cessation of coal combustion option, which allows the Company to comply with the rule by permanently ceasing coal combustion at a unit no later than December 31, 2028. This compliance option provides the Company with additional time to prepare the System for retirements by initiating transmission projects that are necessary to accommodate the combined retirements and the procurement of replacement capacity, while reducing or avoiding additional environmental-related investments for certain resources.

The Company primarily considered the reliability impacts of the retirements to determine the most beneficial date for retirement. The Company first identified the necessary transmission projects and projected time of completion to support retirement through its reliability assessment to determine the earliest possible retirement date for a unit. For example, the assessment revealed that Plant Wansley Units 1-2 could be retired immediately without significant transmission impacts, but for Plant Bowen Units 1-2, certain transmission projects must be completed to maintain reliability upon the retirement of those units. Then, the Company considered the operational needs to support the fleet transition away from the Retirement Units and towards the replacement capacity provided by the six PPAs. Having both sets of resources available during a short overlapping period will benefit customers by providing options for operating the System as the necessary transmission facilities are constructed to facilitate a reliable transition of the fleet.

Q. PLEASE EXPLAIN WHY THE COMPANY HAS REQUESTED DECERTIFICATION OF PLANT BOWEN UNITS 1-2.

A. The economic analysis conducted as part of the Unit Retirement Study in the 2022 IRP indicates that continued operation of Plant Bowen Units 1-2 is uneconomical and not in the best interests of customers. The results of the 2022-2028 Capacity RFP identified cost-effective replacement capacity. Based on the Company's updated reliability assessments, the Company requested retirement of Plant Bowen Units 1-2 upon completion of the necessary transmission system improvements, which is projected to be no later than December 31, 2027.

The unit retirement analysis conducted as part of the 2019 IRP identified Plant Bowen Units 1-2 as units facing potential economic challenges. As directed in the 2019 IRP Order, the Company has significantly reduced capital spending on Plant Bowen Units 1-2. With a known retirement date, the Company can continue to reduce capital budgets as appropriate to maintain the units for serving customers through the end of 2027, as detailed in Table 14 in the Unit Retirement Study. However, if the units continue operations beyond 2027, the Company would need to increase capital spend for these units to ensure their long-term reliable operation.

Q. WHAT ARE THE PLANS FOR PLANT SCHERER UNITS 1-2 FOR WHICH THE COMPANY DID NOT SEEK DECERTIFICATION?

A. Georgia Power plans to install ELG controls on Plant Scherer Units 1-2. Georgia Power owns 8.4% of each Plant Scherer Unit 1 and Unit 2 or 144 MW total. While the economics of Plant Scherer Units 1-2 are challenged, by pursuing the installation of ELG controls through the Voluntary Incentive Program ("VIP") option, the Company has a better opportunity, with this additional time, to adjust to the dynamic regulatory environment, build on its research and development, and update the strategy or pursue retirement should conditions change. However, to reduce the long-term reliance on these units, the Company will undertake certain transmission system improvements to prepare for the ultimate retirement of Scherer Units 1-2. As a minority owner, Georgia Power does not have primary decision-making authority for Plant Scherer Units 1-2. For planning purposes only, the Company has assumed a retirement date of December 31, 2028.

Q. WHY DID THE COMPANY DECIDE TO INSTALL ELG CONTROLS AND CONTINUE TO OPERATE PLANT BOWEN UNITS 3-4?

A. The reliability risks associated with retiring Plant Bowen Units 3-4 are too significant to retire the units in the near term. While Plant Bowen Units 3-4 are not immune to the economic challenges facing the rest of the Company's coal units, these units are critical to preserving System reliability and resiliency in north Georgia, which contains a significant majority of the load served by the Integrated Transmission System ("ITS"). The Company will continue to make prudent investments in the ongoing operation of Plant Bowen Units 3-4, while concurrently taking steps to reduce the Company's long-term reliance on these units as described in the North Georgia Reliability and Resilience Action Plan. For planning purposes, Georgia Power assumes that Plant Bowen Units 3-4 will retire no later than December 31, 2035.

Replacement Capacity Identified in 2022-2028 Capacity RFP

Q. IS THE ECONOMIC VALUE PROVIDED BY REPLACEMENT GENERATION RESULTING FROM THE 2022-2028 CAPACITY RFP A BENEFIT ASSOCIATED WITH THE COMPANY'S COAL UNIT RETIREMENT PLAN?

A. Yes. While customers benefit in many ways from the coal unit retirement plan, a major benefit is the economic value provided by the cost-effective replacement generation afforded by the six PPAs for existing natural gas plants procured through the 2022-2028 Capacity RFP. The Capacity RFP resulted in contracts with capacity prices much lower than those historically paid for such resources and as compared to alternatives submitted into the Capacity RFP. It benefits customers for the Company to take advantage of these contracts, as the market is expected to be more constrained in the next several years, including the years of the Company's next projected need for capacity (2029-2030), due to the increasing number of utilities transitioning away from coal resources. Moreover, these contracts are with existing facilities, which reduces reliability risk during the period of fleet transition.

Q. PLEASE DESCRIBE THE CAPACITY SELECTED FROM THE 2022-2028 CAPACITY RFP.

A. The PPAs with the winning bidders will provide the Company with a total of 2,356 MW of capacity (winter rating) and energy. Five of the six winning PPAs have ten-year terms that commence between December 1, 2024, and January 1, 2028. The sixth winning PPA has a fifteen-year term that commences on December 1, 2024. The winning bidders will supply capacity from existing natural gas facilities that are in commercial operation in Heard County, Jackson County, and Walton County, Georgia and Autauga County, Alabama. The capacity prices from these PPAs are approximately 25-35% lower than the capacity prices associated with existing natural gas PPAs procured through the 2009, 2010, and 2015 capacity RFPs, confirming the success of the 2022-2028 Capacity RFP. As coal retirements reduce the reserve margins in the Southeast, access to these or similar resources, at these pricing levels is expected to be challenging in the future. Also, these PPAs provide customers with access to valuable existing firm transportation for natural gas allowing access to natural gas generation without the risk and costs associated with new natural gas pipelines.

Q. IS GEORGIA POWER INCREASING RELIANCE ON NATURAL GAS?

A. No. Even with the proposed 2022-2028 Capacity RFP PPAs, the Company's natural gas capacity as a percentage of its total capacity is projected to be lower in 2022-2028 than it has been in every year since 2014, due to expiring natural gas PPAs and the addition of other resources, such as solar and nuclear, during the same period.

Q. DOES THE COMPANY'S RESOURCE PLAN PRESERVE FUEL DIVERSITY WHILE NATURAL GAS PRICES ARE CURRENTLY VOLATILE?

A. Yes. The Company's IRP continues to preserve generation diversity benefits in the best interests of customers. Notably, the 2022 IRP reflects substantial increases in new renewables, investments in the hydro fleet, the expected completion of Plant Vogtle Units 3-4, and the orderly transition of the coal generation fleet through 2028 and beyond. This plan ensures a robust set of diverse resources will remain available to help manage natural gas price volatility. Additionally, the majority of the Company's requested gas PPAs do not begin until approximately 2025. Long-term forecasts of natural gas prices, which encompass the period in which energy is delivered to the Company from the 2022-2028 Capacity RFP PPAs, indicate that recent natural gas prices may be a short-term phenomenon. See Figure 1 for the nominal NYMEX futures through 2026.

Figure 1

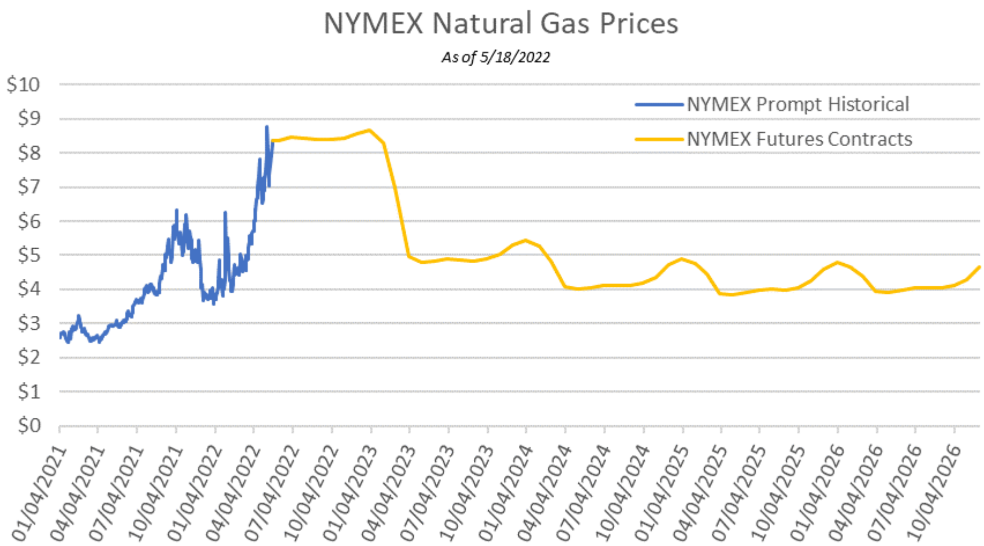
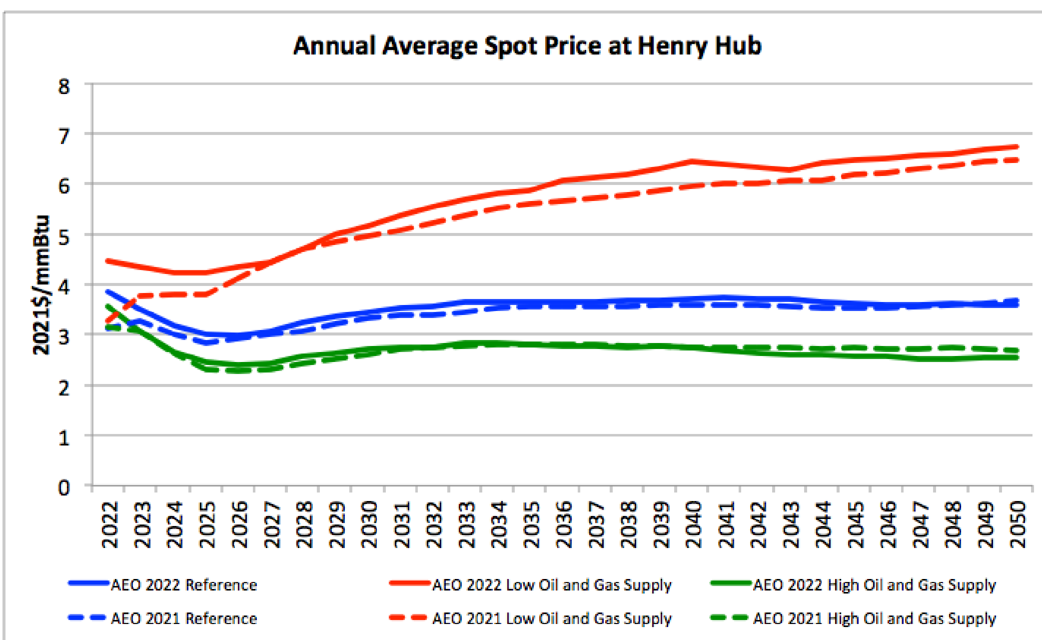


Figure 2 shows the forecasted spot price of natural gas in 2021 dollars according to the Energy Information Administration ("EIA") 2021 and 2022 Annual Energy Outlooks ("AEO").

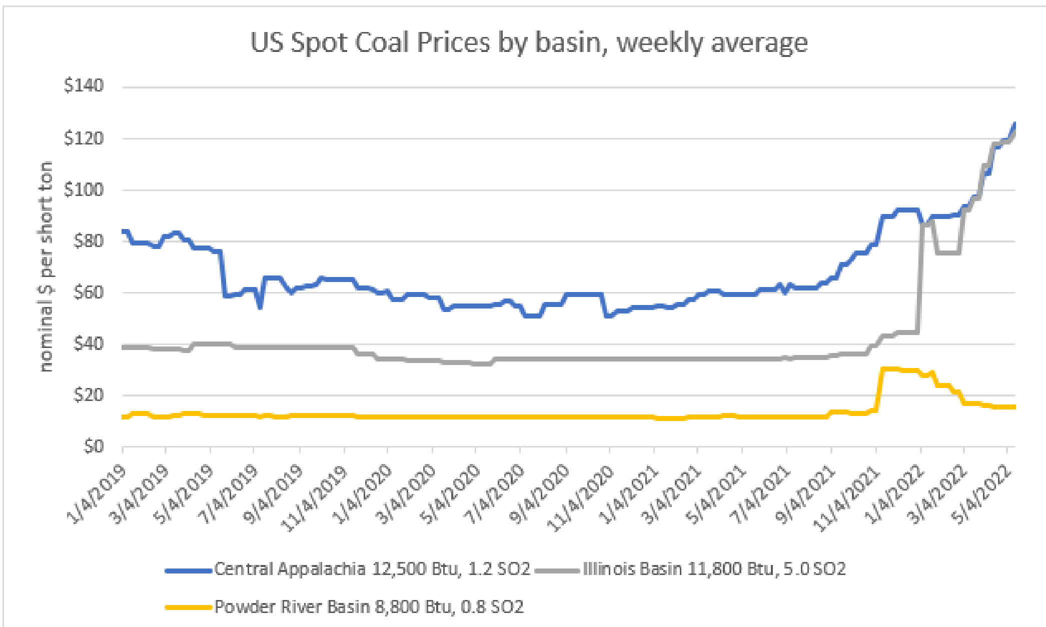
Figure 2



Q. IS THE COMPANY EXPERIENCING VOLATILITY AND SUPPLY CHAIN ISSUES WITH OTHER FUELS?

A. Yes. Recent natural gas price volatility has led to an increased demand for coal. Supply chain issues[4] and a tight labor market have further contributed to changes in the price and supply of coal. Figure 3 shows United States spot coal prices by coal basin from January 2019 through early May 2022.

Figure 3



Q. GEORGIA CENTER FOR ENERGY SOLUTIONS STATED IN ITS TESTIMONY THAT THE RELATIONSHIP BETWEEN SOUTHERN POWER COMPANY AND GEORGIA POWER IS UNMONITORED AND UNREGULATED. PLEASE EXPLAIN WHY THIS IS FALSE.

A. The assertion that Georgia Power's relationship with Southern Power Company is unmonitored and unregulated is false and demonstrates an ignorance of the

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[4] STB Proposes Revised Emergency Service Rules, Surface Transportation Board, News Release No. 22-23 (April 2022) available at https://www.stb.gov/news-communications/latest-news/pr-22-23/.

stringent efforts the Company, Commission Staff, and the Independent Evaluator take to ensure that the Company's RFPs are fair and transparent. The Commission's RFP Rules were established and exist to facilitate a process that allows for affiliate participation to the benefit of customers through a carefully planned and closely monitored process. All members of the Georgia Power Evaluation Team and all members of the Southern Power Bid Team swear and affirm at the beginning and end of the RFP process their adherence to a standard of conduct that imposes a separation and communication protocol between the two teams. At no point during the Capacity RFP (or any Company RFP) is the Georgia Power Evaluation Team permitted to communicate directly with any bidder, including the Southern Power Bid Team. Further, directing that all RFP communications go through the IE Website ensures that all communications are monitored by Commission Staff and the IE. Commission Staff and the IE are actively involved in the drafting of the RFP documents, the evaluation of bids, and the selection of winning bidders. Georgia Power's decision to contract with Southern Power as a winning bidder in the Capacity RFP was completely overseen and confirmed by both Commission Staff and the IE. The IE's Report for the Capacity RFP includes extensive detail on the fair and transparent nature of the Company's RFP, how the Commission Staff and IE oversaw the process, and how the winning bidders were selected. The IE's Report further confirms that the Capacity RFP is compliant with the Federal Energy Regulatory Commission's ("FERC") Edgar Allegheny rules.[5] Finally, the affiliate relationship between Georgia Power and Southern Power is regulated by FERC, and the PPAs entered into between Georgia Power and Southern Power will be filed for review by FERC as well.

[5] Final Report of the Independent Evaluator regarding Georgia Power's 2022-2028 Capacity Request for Proposals, Georgia Public Service Commission, Docket No. 44160 (Feb. 24, 2022) at 6.

Q. WHICH TYPES OF RESOURCES DID THE COMPANY SEEK IN THE CAPACITY RFP?

A. The Company sought 1,000 to 3,000 MW of new or existing capacity resources sized between 100 and 1,200 MW to commence delivery between 2025 and 2028. Resources smaller than 100 MW were permitted to bid if there were multiple units totaling 100 MW or more at the same site. Georgia Power offered to contract through PPAs, with terms of 10, 15, and 30 years, as well as through asset purchase and sale agreements for existing resources and also had the opportunity to submit a Company-owned Proposal. The Company sought resources that were readily available on a dispatchable basis, meaning that the facility could adjust its output in response to Georgia Power's scheduling instructions in a given hour during the term. The Company did not limit the types of resources eligible to participate in the Capacity RFP so long as the resource could meet the firmness and dispatchability requirements. The Company expected (but did not limit the solicitation to) resources such as natural gas, biomass, oil, nuclear, hydro, and wind or solar paired with storage. Georgia Power specifically stated that both a firm standalone storage resource as well as firm storage resource paired with another renewable energy resource were welcome to bid into the Capacity RFP. Georgia Power also required all combined cycle and battery energy storage systems to be capable of operating on automatic generation control ("AGC").

Q. GEORGIA LARGE-SCALE SOLAR ASSOCIATION ("GLSSA") AND ADVANCED POWER ALLIANCE ("APA") ARGUED THAT THE ECONOMICS OF A STORAGE PLUS CHARGING SOLAR BID BECOMES NON-VIABLE IF UNSCHEDULED ENERGY IS PURCHASED AT 15% OF THE COMPANY'S AVOIDED COST. PLEASE EXPLAIN WHY THIS IS FALSE.

A. Sellers are paid a capacity price and can price their bids appropriately to account for any perceived economic or pricing risk, such as the appropriately low price of unscheduled energy. The Capacity RFP was approved to seek firm (scheduled) capacity and energy, not unscheduled or intermittent excess energy. So long as the proposed facility meets the PPA's availability requirements, the Seller is provided a fixed monthly capacity payment regardless of the output of the facility. Because Georgia Power is paying Sellers a fixed monthly capacity payment for the right to schedule the dispatchable facility's output precisely when needed to meet System needs, the PPA appropriately minimizes costs for customers by providing minimal additional payment when the Facility delivers unscheduled energy.

Q. GLSSA AND APA STATED THAT STORAGE PLUS CHARGING SOLAR RESOURCES WERE REQUIRED TO ALWAYS BE CHARGED AT 100%, EFFECTIVELY REQUIRING TWICE THE AMOUNT OF STORAGE COMPARED TO THE SIZE OF THE BID. IS THIS TRUE?

A. No. This argument is based on a fundamental misinterpretation of the Capacity RFP's terms and conditions, despite Georgia Power's clarification in response to a similar question that was asked during the public comment period. Notably, members of GLSSA and APA submitted bids in to the 2022-2028 Capacity RFP, and none of these bids reflected such a misconception. Appendix C of the 2022-2028 Capacity RFP Pro Forma PPA for BESS plus Charging Solar required the Facility to be capable of meeting Georgia Power's schedules at all times, 24 hours a day, seven days a week. This requirement does not mean that the storage resource was required to always be charged at 100%. It would be an impossibility to require a 100% charge because, by definition, once the storage resource discharges energy, it will no longer be charged at 100% and recharging would be required. Rather, the 24/7 requirement means that the battery must be capable of being scheduled around the clock and not limited in operation to certain hours of the day. Appendix C further identified minimum capacity limits, maximum ramp rates, minimum scheduled and down times, required start up notification (minutes/hours), and the maximum number of cycles per day. By specifying these performance criteria, it is clear that the Company did not expect or require that a storage resource paired with solar be charged 100% of the time.

Q. WHY IS THE COMPANY SEEKING AN ADDITIONAL SUM FOR THE PPAS SELECTED IN THE CAPACITY RFP?

A. Consistent with O.C.G.A. § 46-3A-8 and Commission Rule 515-3-4-.11(3)(a), in addition to recovering the cost of a long-term power purchase, the Company shall earn an additional sum. In determining the additional sum, the Commission is directed to consider not only shared savings, but also increased risks and lost revenues. As such, the Company requests an additional sum that is based on the benefits the PPAs provide and consistent with the requirements of the additional sum statute and Commission Rule.

Q. IS THE COMPANY'S PROPOSED ADDITIONAL SUM METHODOLOGY APPROPRIATE?

A. Yes, the Company's proposed methodology considers shared benefits, changed risks, and lost revenues. The shared benefits and lost revenues included in the proposed additional sum are based on a comparison to the Company-owned Proposal. The Company-owned Proposal was not selected as a winning bid but was more economical than other bids on the Competitive Tier. It is the repeatable, commercially viable alternative that the Company would deploy absent a market for capacity and energy available from independent power producers. While the Company is contracting with existing resources, changed risks are present as the Company increases its purchased power percentage. As such, the requested additional sum is an appropriate incentive for the Company to make such long-term purchases.

Q. DID STAFF PROVIDE AN EVALUATION TO SUPPORT ITS PROPOSED $2.30/KW-YR ADDITIONAL SUM?

A. No. Staff recommends that the Company continue to receive the additional sum at the same value that was first approved by the Commission more than 20 years ago.

Q. WHAT IS THE BASIS OF THE $2.30/KW-YR VALUE?

A. The $2.30 per kilowatt ("kW") year value is the historical additional sum awarded to the Company stemming from the certification of the West Georgia Capacity PPA in 2000. Notably, this amount was not intended to be relied upon as binding precedent on the Commission in determining future additional sum values. However, the $2.30/kW-year was a stipulated value based on 20% of shared savings. When this historical savings threshold is compared against the savings provided by the 2022-2028 Capacity RFP PPAs compared to the Company-owned Proposal, the $2.30/kW-year represents a savings of only 5-7%, rather than 20%.

2029-2031 All-Source RFP

Q. STAFF RECOMMENDS THE COMPANY INITIATE AN ALL-SOURCE RFP FOLLOWING THE 2022 IRP TO PROCURE CAPACITY FOR 2029-2031. DOES THE COMPANY AGREE WITH STAFF'S PROPOSED TIMELINE TO MEET CAPACITY NEEDS IN 2029-2031?

A. The Company generally agrees in principle. However, the Company would first need to determine its next capacity need year following a final order in the 2022 IRP and then calculate a load forecast update in Q3 2022. Once the updated capacity needs are identified, the Company can utilize an RFP timeline and schedule similar to that used in the 2022-2028 Capacity RFP, which was initiated in 2019 to meet needs as soon as 2025.

Hydroelectric Investment

Q. IS GEORGIA POWER PROPOSING TO CONTINUE INVESTING IN ITS HYDRO FLEET?

A. Yes. The Company proposes to continue investing in its hydro fleet, focusing on Plant Burton, Plant North Highlands, and Plant Sinclair for the 2022 IRP. The units at each of these three Plants have the most pressing need for investment to avoid extended outages in the near future. As originally explained in the 2019 IRP, the Company proposes to continue investment in its hydro fleet in groups of facilities as part of its overall strategic plan to modernize the hydro fleet. A key component of the Company's strategic plan is the staggered and sequenced order in which the units are updated to optimize resources, design, planning, and project execution in an efficient manner.

Q. ARE THESE HYDRO PLANTS REGULATED BY FERC?

A. Yes. FERC regulates and issues licenses for hydroelectric "projects," which includes, among other things, a powerhouse, dams, and reservoirs.[6]

Q. DO THE FERC LICENSES FOR THE COMPANY'S PROJECTS REQUIRE THE GENERATION OF POWER?

A. Yes. Section 10(c) of the Federal Power Act requires the licensee to maintain the physical structures of the project for efficient operation in the development and transmission of power.[7] In other words, to remain in compliance with the Company's FERC operating licenses, the Company must maintain the hydro units in operable condition.

Q. DO THE FERC LICENSES ALSO INCLUDE REQUIREMENTS RELATED TO WATER FLOW MANAGEMENT?

A. Yes. The licenses include specific requirements related to items such as minimum and seasonal flows for a project, which are important factors in the operation of a project.

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[6] Definition of "projects" within the Federal Power Act, 16 U.S.C. 793, Section 3 (11) available at https://www.ferc.gov/sites/default/files/2021-04/federal_power_act.pdf.

[7] Federal Power Act, 16 U.S.C. 802, Section 10(c) available at https://www.ferc.gov/sites/default/files/2021-04/federal_power_act.pdf.

Q. CAN THE COMPANY APPROPRIATELY MANAGE LAKE LEVELS USING SPILLWAY GATES OR OTHER MEANS WITHOUT GENERATING POWER AS SUGGESTED BY STAFF?

A. No. Spillway gates at the Company's hydroelectric projects are designed for passing flood flows. Therefore, they are designed to only pass large flows of water and to keep lake levels from exceeding the elevation of the gates for dam stability purposes. These high spillway gate flow releases are too large to precisely manage lake levels and minimum and seasonal flow releases required by the FERC licenses. Only turbine units can facilitate this finer precision flow release. Spillway gates physically cannot pass flows below the elevation of the spillway gates. If the Company were unable to generate power by moving water through the turbine, which is the most precise and effective way to regulate lake levels under normal flow conditions, then it would be out of compliance with its FERC license. To retrofit the hydro facilities to pass water to meet FERC license requirements without turbines would require additional investment and civil retrofits.

Q. IS THE PURPOSE OF THE COMPANY'S HYDRO INVESTMENT TO INCREASE EFFICIENCY AT THE HYDRO PLANTS?

A. No. Increased efficiency is one benefit of the Company's hydro investment, but not the primary goal. The purpose of the Company's continued investment in its hydro units is to maintain the ability to operate the hydro plants for many years into the future and to prevent extended forced outages, which is necessary for safely regulating lake levels and licensed minimum and seasonal flows. This goal is accomplished by replacing major components, such as turbines and generators, which are now beyond their expected lives, through a strategic approach that minimizes outages and river and lake impacts and optimizes engineering and construction resources.

Q. WHY IS IT NECESSARY TO CONTINUE INVESTING IN ADDITIONAL HYDRO PROJECTS AT THIS TIME?

A. The Company always intended to target the entire hydro fleet through a strategic planning effort that will optimize resources as well as design, planning, plant performance, river management, and the execution of related work. As the hydro units continue to age, the plants that have not yet been approved for additional investment are increasingly likely to experience extended outages and equipment failures. The Company identified Plant Burton, Plant North Highlands, and Plant Sinclair as the facilities most at risk of potential equipment failure and long-term forced outages. Thus, the Company requested these three plants as the next projects in the queue for additional investment. It is important to continue the momentum of the modernization program to be able to leverage the existing, experienced engineering teams as well as economies of scale when procuring parts. In addition, there is extensive time required for design, engineering, and procuring the highly specialized parts required. A delay in program implementation is more likely to lead to long-term forced outages, which may last for years before repairs can be implemented. Such outage would result in lost generation from the Company's most flexible resources in an unplanned and unpredictable manner, with little to no resources available to resolve the issues, and further require action to restore the units to service in order to maintain the FERC licenses. As such, the Company must continue to proactively address these issues in the modernization program.

Q. DID THE COMMISSION APPROVE THE COMPANY'S PLANS TO MODERNIZE PLANT TUGALO DURING THE 2019 IRP?

A. Yes. In the Commission's Order Adopting Stipulation as Amended, filed on July 29, 2019, the Commission approved five modernization projects, including Plant Tugalo.

Q. IS THERE CURRENTLY A LICENSE AMENDMENT APPLICATION FOR PLANT TUGALO UNDER REVIEW AT FERC?

A. Yes. As part of the Company's proposed modernization process at Plant Tugalo, Georgia Power filed a non-capacity license amendment application at FERC on September 23, 2021. Restore Chattooga Gorge has intervened and submitted comments in the FERC proceeding and is actively engaged in FERC's evaluation of the Company's proposed non-capacity license amendment.

Q. WOULD REMOVAL OF THE DAM AT PLANT TUGALO ADVERSELY IMPACT OPERATIONS AT NEARBY DAMS?

A. Yes. Removal of the dam at Plant Tugalo would adversely impact operations at Plants Yonah, Tallulah, Terrora, Nacoochee, and Burton. With no lake upstream of Tugalo Dam to attenuate fluctuations in river flows, the flow through Yonah Dam would become more erratic and impact the reliability of generation.

Moreover, removing Tugalo Dam would drop the tailwater of the Tallulah Powerhouse to much lower levels. The turbines in any hydroelectric plant are designed to operate under certain headwater and tailwater conditions. The extreme low tailwater level resulting from removal of Tugalo Dam would render the Tallulah turbines inoperable.

Technology Advancements

Q. STAFF RECOMMENDS THAT THE COMPANY SHARE COSTS RELATED TO THE TALL WIND DEMONSTRATION PROJECT WITH ALABAMA POWER COMPANY AND MISSISSIPPI POWER COMPANY ON A PRO RATA BASIS. IS THIS APPROPRIATE?

A. No, it is not appropriate to request that Alabama Power Company and Mississippi Power Company share the costs of a project that primarily benefits Georgia Power and the state of Georgia. The proposed wind resource will be built in Georgia, will increase tax revenues in Georgia, will serve Georgia Power customers, and will generate energy that is complementary to the Company's solar generation. As a Georgia Power project, the Company controls the design, siting, learning objectives, and all elements of the project to the benefit of Georgia customers. Because of Georgia's leading position in the development of solar resources and based on the complementary production characteristics of the energy that wind provides, Georgia Power and its customers stand to benefit from the learnings from this project far more than the other Operating Companies. Therefore, the Tall Wind demonstration project should be approved as proposed.

Q. STAFF RECOMMENDS THAT THE COMPANY SHARE COSTS RELATED TO THE INTEGRATED HYDROGEN MICROGRID PROJECT WITH ALABAMA POWER COMPANY AND MISSISSIPPI POWER COMPANY ON A PRO RATA BASIS. IS THIS APPROPRIATE?

A. No, it is not appropriate to request that Alabama Power Company and Mississippi Power Company share in the costs of a project that primarily benefits Georgia Power and the state of Georgia. The infrastructure will be installed at a Georgia Power fleet vehicle facility and operated by Georgia Power. The vehicles will be configured to meet Georgia Power specifications for specific use-cases within the Georgia Power fleet. Energy produced by the hydrogen microgrid will be consumed by Georgia Power customers, and hydrogen used for transportation purposes will be consumed by Georgia Power trucks.

Q. WHAT PORTION OF THE INTEGRATED HYDROGEN MICROGRID PROJECT COST IS COVERED BY GEORGIA POWER?

A. Georgia Power is paying less than ten percent of total project costs due to external funding available. This funding substantially reduces the cost to the Company's customers. Failing to fully fund the Company's share of the project costs will put the project at significant risk of moving forward and potentially miss the opportunity for Georgia Power's customers to benefit from the availability of this project.

Q. STAFF AGREES THAT RESEARCH INTO IRON-AIR BATTERY STORAGE TECHNOLOGY MAY BE BENEFICIAL TO GEORGIA POWER'S CUSTOMERS. WHEN DOES THE COMPANY PLAN TO BRING A PROJECT BEFORE THE COMMISSION FOR APPROVAL?

A. The Company continues to evaluate the viability of Iron-Air Battery Storage, and when it identifies an optimal application to demonstrate this multi-day storage technology, it will bring a proposal back to the Commission for review and approval.

V. <u>NORTH GEORGIA RELIABILITY AND RESILIENCE ACTION PLAN</u>

Q. WHAT IS THE NORTH GEORGIA RELIABILITY AND RESILIENCE ACTION PLAN?

A. The North Georgia Reliability and Resilience Action Plan is a multi-faceted strategic plan that establishes a comprehensive and coordinated approach to address the growing gap between generation and load in north Georgia. To serve the state in the most reliable and economic manner as the Company transitions its fleet and expands renewable resource growth, the development of the generation supply system and the transmission system must be considered as a whole and in parallel. To that end, the North Georgia Reliability and Resilience Action Plan provides an integrated transmission and generation strategy addressing these reliability concerns.

Q. WHY IS THE COMPANY PROPOSING THE NORTH GEORGIA RELIABILITY AND RESILIENCE ACTION PLAN IN THIS IRP?

A. The existing transmission system is becoming increasingly strained due to the continued addition of renewable resources in south Georgia. Additionally, there is a significant gap between generation and load forecasted in north Georgia. The eventual retirement of Plant Bowen will further exacerbate this gap and place even more strain on the transmission system. As unit retirements in north Georgia occur, the Company must enhance both its generation and transmission systems and its operational capabilities to avoid the potential for a major loss of load (i.e., outages). The Company cannot achieve this capability overnight, as required transmission system improvements involve long lead times and considerable resources. Therefore, given the number of System constraints and time required for completion of transmission system improvements, the Company's plan includes the continued operation of Plant Bowen Units 3-4 with ELG controls in place as well as the issuance of the north Georgia Renewable RFP. These actions will ensure reliability and resilience of the System while the North Georgia Reliability and Resilience Action Plan is executed.

Q. WHAT ARE THE COMPANY'S ACTIONS THAT MAKE UP THE NORTH GEORGIA RELIABILITY AND RESILIENCE ACTION PLAN?

A. The Company projects that it will complete transmission system improvements identified in the ten-year transmission plan necessary to support the retirement of Plant Bowen Units 1-2 by December 31, 2027. To reduce the long-term reliance on Plant Bowen Units 3-4 and allow for continued future development of solar in south Georgia, the Company will (i) install ELG controls on Plant Bowen Units 3-4 to allow for continued operation, (ii) issue the north Georgia Renewable RFP, (iii) work with the ITS Participants to develop a strategic portfolio of projects to address the long-term transmission planning and operational needs of north Georgia beyond the retirement of Plant Bowen Units 3-4, and (iv) develop a consolidated expansion plan addressing future generation needs for north Georgia.

Q. WHAT ARE THE BENEFITS TO SITING RENEWABLE GENERATION IN NORTH GEORGIA?

A. There are several benefits associated with the strategic siting of new renewable resources in north Georgia. Locating generation closer to load centers enhances the reliability and resiliency of the System. Given the large penetration of renewable resources in south Georgia, geographic diversity is needed to help protect the System against severe weather events and weather anomalies. For example, if there is a hot summer day with high load in north Georgia while severe weather is occurring in the southern part of the state, the System could be vulnerable to reliability issues due to the reduction of solar output from existing resources in south Georgia. By creating geographic diversity in its renewable resources, the System is better protected against these types of scenarios. Selecting renewable resources in north Georgia through the first utility scale RFP will allow the Company to continue the procurement of renewable resources while transmission infrastructure is being built that will eventually support additional utility scale renewable development in south Georgia. Without additional time to build the necessary infrastructure to support moving energy from south Georgia to north Georgia, the Company's utility scale renewable procurements and targeted commercial operation dates will be at risk of significant delay, thus disrupting the success of future renewable RFPs if not focused on north Georgia. It is critical to the continued steady and measured deployment of renewable resources that at least the first utility scale renewable RFP be geographically targeted to projects sited in north Georgia.

Q. STAFF AND SOME INTERVENORS RECOMMEND THAT RATHER THAN LIMIT THE RFP TO NORTH GEORGIA, BENEFITS EQUAL TO THE COST TO SUPPORT SOUTH GEORGIA BIDS SHOULD BE

ATTRIBUTED TO NORTH GEORGIA BIDS. PLEASE EXPLAIN WHY THIS IS NOT APPROPRIATE.

A. The Company's proposal to target utility scale renewable projects in north Georgia is not a cost issue and cannot simply be addressed by imputing costs attributable to south Georgia bids to bids in north Georgia. Rather, the issue relates to physical infrastructure and delivery capabilities that will create interconnection and required commercial operation date delays for projects in south Georgia because of limited transmission capacity on the existing transmission system. In addition, opening the first utility scale RFP to statewide bids will likely result in fewer bids in the north Georgia area where generation is needed. Put simply, the physical infrastructure to support transmission between south and north Georgia must be built to support generation in south Georgia; it is not simply an issue of cost. Staff's proposal does not address the lack of physical infrastructure to support generation and, therefore, does not address the issue to be resolved by the north Georgia Renewable RFP.

Staff's proposed methodology to credit an RFP bid with the benefit of being located in north Georgia is also not practical. First, it is not fair to credit new renewable facilities for transmission issues other than those created by an overabundance of renewable resources siting in south Georgia. Second, it is impossible to accurately identify the costs to create such an adder prior to the issuance of the RFP, as project-specific transmission costs based on the specific location and generation characteristics must be identified. Third, Staff's proposed methodology is unlikely to result in cost savings aside from the benefit of getting more renewable resources on-line sooner. Finally, the Company's existing RFP evaluation process already properly identifies all appropriate transmission system costs and benefits and represents a superior methodology to allocate costs and benefits of individual renewable bids.

Q. GLSSA AND APA RECOMMEND REQUIRING THE COMPANY TO COMPLETE THE NORTH-SOUTH TRANSMISSION IMPROVEMENTS IN FOUR YEARS. IS THIS FEASIBLE?

A. No. As previously explained in testimony during the Company's direct hearings, and as supported by Witness Chiles' testimony in Staff hearings, the time to design, acquire rights of way, and build greenfield 230-kV and 500-kV transmission projects is between six to eight years. The strategic projects needed to address the long-term planning and operational needs of the transmission system as proposed in the North Georgia Reliability and Resilience Action Plan will likely be mostly greenfield. Due to the number of system constraints and the time required to construct and schedule system improvements, the Company cannot complete the large volume of direct rebuild and reconductor projects that would be necessary to allow the existing transmission system to accommodate new south Georgia renewables while maintaining System reliability and resiliency absent the North Georgia Reliability and Resilience Action Plan. When coupled with normal maintenance and outage activities, the large volume of required projects would put the transmission system at risk of major loss of load. Strategic new greenfield projects lessen the overall impact to the transmission system while under construction compared to relying solely on upgrading existing transmission facilities.

The project process for new transmission lines includes engineering, design, land acquisition, permitting, and construction. For lines over 50 miles, surveying and mapping of line routes can take approximately one year to complete. For projects contemplated in the North Georgia Reliability and Resilience Action Plan, considerable time will be required to host public meetings, seeking comment from members of the public, and to provide official notice to property owners before land acquisition can begin. The entire process for acquiring land can take up to three years. The timeframe needed to construct greenfield transmission projects is dependent upon many variables, including the voltage of the line, line length, terrain, soil conditions, weather, availability of material and construction crews, railroad and highway crossings, and environmental situations that require permitting with multiple agencies. The Company estimates that a 50-mile 230-kV line can take up to five years to construct and a 50-mile 500-kV line can take up to six years to construct. For all these reasons, it is not feasible to complete the required North-South transmission improvement projects in four years or less.

Q. STAFF RECOMMENDS THAT THE COMMISSION ESTABLISH A COLLABORATIVE LONG-TERM TRANMISSION PLANNING PROCESS ADDRESSING NORTH GEORGIA ISSUES PRIOR TO THE 2025 IRP. IS THE COMPANY CURRENTLY INVOLVED IN EXTENSIVE AND COLLABORATIVE LONG-TERM TRANSMISSION PLANNING PROCESSES?

A. Yes, the Company is involved in robust and collaborative planning processes primarily through both the Georgia ITS and Southeast Regional Transmission Planning ("SERTP") processes. The Company outlines the planning processes for the ITS in Sections A, B, and D of Technical Appendix Volume 3 and in Section E1 for SERTP. Outside stakeholders such as developers and Commission Staff regularly attend the quarterly SERTP meetings. The stakeholders can provide input on transmission plans through the quarterly meetings. Information on how to participate in the meetings is posted publicly on the Company's Open Access Same-Time Information System ("OASIS") website and through the SERTP website.

Q. WILL ADDITIONAL STAKEHOLDER INVOLVEMENT AND PROCESSES HELP THE COMPANY COMPLETE THE IDENTIFIED PROJECTS?

A. No. The Company believes that additional stakeholder involvement will introduce significant delays in its transmission planning processes. As mentioned in this testimony, extensive collaboration processes already exist through numerous ITS working groups, stakeholder engagement through SERTP with regional transmission planning entities, and eastern interconnection coordination and planning through the Eastern Interconnection Planning Cooperative ("EIPC"). Additional stakeholder involvement would impede the Company's ability to jointly plan transmission projects with ITS Participants to support the timely transition of the generation fleet to more economical and cleaner resources. Updating Commission staff on a semi-annual basis to provide updates on strategic North-South transmission projects is a more efficient approach to ensure these projects are completed in a timely manner.

Q. HAS THE COMPANY ALREADY IDENTIFIED PROJECTS THAT ARE NEEDED FOR ITS PROPOSED UNIT RETIREMENTS THROUGH 2028?

A. Yes. These projects are listed in Technical Appendix Volume 1, Selected Supporting Information, Transmission Retirement Projects.

Q. ARE TRANSMISSION PROJECTS FOR PLANT BOWEN UNITS 1-2 STILL NEEDED IF THE COMMISSION DEFERS THE RETIREMENT OF ONE OF THE UNITS TO 2035?

A. Yes. Although studies that reflect a deferred retirement of Plant Bowen Unit 1 or 2 have not been completed, projects identified for the retirement of both units are still likely to be needed even with only one unit retiring. Therefore, projects should commence without delay to maintain the option of retirement at the earliest possible date in case of additional future environmental pressure. The Company will continue studying and identifying strategic transmission projects necessary for the eventual retirements of all units at Plant Bowen and the continued addition of renewable resources in south Georgia. As previously stated, the time required to build greenfield transmission projects is between six and eight years. Accordingly, the currently identified transmission projects related to the retirement of Plant Bowen Units 1-2 should still begin as soon as possible, regardless of whether retirement is delayed.

Q. STAFF WITNESS ALVAREZ REFERS TO INCREASES IN TRANSMISSION AND DISTRIBUTION INVESTMENTS THAT WILL BE REVIEWED IN THE 2022 RATE CASE. ARE THOSE INVESTMENTS RELATED TO THE GRID INVESTMENT PLAN THAT WAS APPROVED IN THE 2019 RATE CASE?

A. Yes, with respect to distribution capital investment, 2020 and 2021 budget increases are directly attributable to the Grid Investment Plan approved by this Commission in 2019. When the capital spend for grid investment is removed in 2020 and 2021, distribution investment is flat in 2020 and lower by 4% in 2021 as compared to 2019. This demonstrates that increases in distribution capital spend in recent years correlates directly to the Company's implementation of the Grid Investment Plan. Transmission-related Grid Investment Plan spending accounts for a small percentage of overall transmission investment due to minimal transmission work occurring in the first three years of the program. Contrary to Staff's testimony, transmission capital investment has not experienced "dramatic" increases in recent years. Adjusting for inflation at 2.5%, transmission capital investment was only 5% higher in 2021 than in 2018.

Q. STAFF WITNESS CHILES AND GLSSA CLAIM THE COMPANY DID NOT ACT FAST ENOUGH TO RESPOND TO FUTURE COAL RETIREMENTS AND THE BUILD OUT OF SOLAR IN SOUTH GEORGIA. IS THIS A SITUATION THE COMPANY COULD HAVE ANTICIPATED IN THE 2019 IRP OR EARLIER?

A. No. In 2019, the Company could not have anticipated or planned for the evolution of the System as illustrated in the 2022 IRP. In the 2019 IRP, the Company did not know the location or cost of replacement generation for potentially retiring units, such as Plant Bowen Units 1-2. In addition, the Company's request to procure energy from 1,050 MW of renewable resources was instead more than doubled to a target of 2,210 MW of renewable resources over the next three years. Since the Company filed the 2019 IRP, more than 12,000 MW of renewable generation have been entered in the Southern Company OASIS Generation Interconnection queue in Georgia with most of those requests located in south Georgia. When including the other ITS Participants' OASIS Interconnection queues, that number grows to more than 17,000 MW, representing a significant and dramatic shift in a short period of time. The Company has also seen a dramatic shift in interest in renewable resources from its customers as evidenced by the full subscription of the Customer Renewable Subscription Procurement ("CRSP") program and recent economic development activity.

Q. HAS THE COMPANY PROVIDED INFORMATION ON THE USES OF NON-WIRE ALTERNATIVES IN THIS IRP AND IN PRIOR IRP FILINGS?

A. Yes. The Company provided responses to various data requests in both the 2019 and 2022 IRPs with respect to non-wire alternative or non-traditional solution uses in its transmission planning processes. In 2019, the Company hosted an informational meeting with the Staff and Mr. Chiles to highlight how battery storage was not an effective non-wire alternative for mitigating constraints identified through NERC TPL-001 compliance analysis, which was acknowledged by Commission Staff in the 2019 Rate Case.[8] The informational session was held on September 10, 2019. In addition, Witness Robinson filed testimony in the 2019 Rate Case illustrating how the Company included non-traditional solutions in its analyses.

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[8] Georgia Power's 2019 Rate Case, Georgia Public Service Commission, Docket No. 42516, November 5, 2019 Hearing at Tr. 1805.

Q. IS IT FEASIBLE FOR THE COMPANY TO INCLUDE AN ASSESSMENT OF ECONOMIC CONGESTION AS PART OF THE LOCATIONAL VALUE STUDY?

A. No. Given the Company's current planning processes, it is not feasible to model economic congestion as part of the locational value study. The transmission system is planned proactively to avoid and eliminate congestion on the system. Assessing economic congestion on the system is reflective of practices that an RTO employs. The Company is opposed to adopting study methodology that resembles an RTO and prefers to continue its proactive approach to planning the transmission system.

VI. <u>ENERGY STORAGE</u>

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED DEPLOYMENT OF ENERGY STORAGE SYSTEMS.

A. As the penetration of renewable energy resources continues to grow, the Company has identified the corresponding need to add ESS to the System to ensure reliability most effectively for customers. As supported by the Renewable Integration Study ("RIS"), Georgia Power proposes to own and operate 1,000 MW of ESS by 2030 to support System operational and reliability requirements as renewable penetration increases. The Company proposed the 265 MW McGrau Ford Battery Facility as a part of this plan.

Q. STAFF AND INTERVENORS CLAIM THAT CAPACITY AND ENERGY FROM ENERGY STORAGE SYSTEMS COULD BE PROVIDED TO THE COMPANY BY THIRD PARTIES. WHY IS THE COMPANY'S PLAN TO OWN AND OPERATE ENERGY STORAGE RESOURCES NECESSARY TO MAINTAIN RELIABILITY?

A. The Company must be able to reliably serve customers. To ensure that reliability is maintained in a cost-effective manner, the Company must maintain a sufficient portion of the energy storage resources on the System under its ownership and control. The storage resources for which the Company is requesting approval in this IRP will be utilized to efficiently provide essential load balancing services or operating reserves. Historically, Georgia Power has owned and operated many of the System's baseload resources that have been relied upon to economically serve load and provide essential load balancing services and operating reserves. These resources are the cornerstone of providing reliable service to customers.

As discussed in the RIS, as the fleet transitions and the resource mix evolves to include more intermittent resources, the Company will face many challenges that make Company ownership of ESS resources essential. ESS provided only through third parties pursuant to PPA contracts restricts Georgia Power's access to the battery energy storage capabilities as identified and required per the terms of the contractual agreements. Georgia Power will have greater flexibility to adapt its use of these resources more quickly and over time if Georgia Power owns the ESS. Georgia Power ownership and control of these energy storage resources will maximize benefits to customers by enabling the flexibility needed for continued delivery of reliable electricity service our customers depend on.

Q. STAFF EXPRESSED MULTIPLE CONCERNS WITH THE RIS. IS IT REASONABLE TO USE ACTUAL DATA TO PROJECT RELIABILITY COSTS FOR A FUTURE SYSTEM WITH SIGNIFICANTLY MORE RENEWABLES THAN ARE CURRENTLY ONLINE?

A. No. While actual operating data can be informative, part of why the Company models its System when making resource planning decisions is that the Company does not have actual data for a future System. To expect the Company to solely use actual data in projecting a future System is unreasonable. It is not appropriate to ignore identified reliability needs when planning its System to wait for real-time reliability events for measurement purposes.

Q. CAN THE COMPANY HAVE RELIABILITY CONCERNS AND INCUR OPERATIONAL COSTS WITHOUT VIOLATING NERC STANDARDS?

A. Yes. Southern Company's operations personnel, including the Balancing Authority ("BA") manage the real-time balancing of load and generation. This includes calculating Area Control Error ("ACE") on a six second basis as required by NERC. Although the NERC BAL-001-2 standard referenced in the RIS specifies that ACE should not exceed a predefined limit on a thirty-minute basis, ACE and Control Performance Standard 1 ("CPS1," a measure of ACE volatility and interconnection frequency error) are tracked on a one-minute basis for complying with the standard. The BA properly manages ACE to maintain frequency and ensure that no undue burden is placed on any neighboring Balancing Authority Area ("BAA"). If generating resources are not sufficient to match load, then unscheduled power interchanges occur. The BA is obligated to repay any imbalance, which comes at a cost to customers. It is not the Company's practice to depend on unscheduled power flows with its neighbors to integrate solar generation. Instead, the BA and other System operators take action such as increasing regulating reserves to ensure that load and generation are balanced within reasonable limits. These actions are not free, and result in increased production costs.

Q. DOES THE RIS REASONABLY CAPTURE THE COSTS YOU ARE DESCRIBING?

A. Yes. Although the RIS did not model load and generation imbalances on a real-time basis, the model approximated real-time using a five-minute simulated dispatch. The purpose of the mitigation cases modeled in the RIS was to return the System to a base level of reliability, with the understanding that the base level of reliability is compliant with the relevant NERC standards. By mitigating these additional imbalances between load and generation in the model, which in the study are called "flexibility violations," the System does not place undue burden on interconnected neighbors, consistent with actual operations. The mechanism the model used to mitigate flexibility imbalances increased operating reserves, consistent with actual practice, which resulted in increased production costs. The RIS also performed scenarios where ESS was added to the System, which resulted in a lower production cost. This production cost difference is the flexibility benefit that is attributable to Company-owned and operated ESS, as reflected in the Battery Storage Cost Benefit Analysis. The RIS provides a sound, model-based representation of the costs that the System incurs to mitigate the ramping and variability impacts due to increased levels of solar generation on the System, and the benefit that ESS provides by mitigating these impacts at a lower production cost.

Q. BESIDES GEORGIA POWER, DID ANY OTHER PARTY CONDUCT A RENEWABLE INTEGRATION STUDY IN THIS CASE?

A. No other party conducted a renewable integration study or production cost simulation that identifies the reliability needs of the System in this case.

Q. DESPITE ITS CONCERNS, DID STAFF CALCULATE A RENEWABLE INTEGRATION COST BASED UPON GEORGIA POWER'S METHODOLOGY?

A. Yes. Staff's Barber, Cook, and Bower panel calculated an incremental integration cost of \$1.93/kW-year based on costs and solar penetration from Georgia Power Scenarios B and C. The panel agreed that this integration cost would be appropriate for the next tranche of solar resources.

Q. DOES COMMISSION STAFF VIEW THE MCGRAU FORD BATTERY PROJECT AS BENEFICIAL FOR GEORGIA POWER CUSTOMERS?

A. Yes, Commission Staff recommends that the Commission approve the McGrau Ford battery project. Commission Staff's recommendation noted that the Company should be required to provide its final McGrau Ford Engineering, Procurement, and Construction Agreement to the Commission prior to undertaking construction and procurement for the project.

Q. WHAT ARE THE COMPANY'S NEXT STEPS FOR ESS?

A. If approved by the Commission, the Company intends to implement its battery storage procurement action plan identified in the 2022 IRP Main Document to further the goal of fulfilling 1,000 MW of ESS by 2030. Georgia Power will continue to identify and secure viable sites across the state for new storage resources, complete site layout and engineering drawings, and initiate transmission interconnection studies, as appropriate. At the appropriate time in the development process, the Company will issue a competitive RFP for storage resources and select favorable proposals based on its evaluations and supporting cost benefit analyses. Finally, the Company will return to the Commission for approval of each ESS project before beginning construction, consistent with the Mossy Branch Battery Facility approval process.

Q. WILL THE COMPANY CONTINUE TO PROCURE STANDALONE ENERGY STORAGE OR ENERGY STORAGE PAIRED WITH RENEWABLE RESOURCES THROUGH THE COMPANY'S RENEWABLE AND CAPACITY RFPS?

A. Yes. The Company will continue to rely upon the market through competitive solicitations in meeting customer needs that will include opportunities for standalone storage resources and storage paired with renewable resources to compete in future capacity RFPs, and the Company will continue to solicit bids for energy storage paired with renewable resources in its renewable RFPs. Further, the Company's existing approach for bifurcating its capacity RFPs and renewable-only RFPs is efficient for the market and ensures that the Company offers and receives an appropriate mix of resources to best serve customers.

VII. <u>RENEWABLE RESOURCES</u>

<u>Renewable Expansion Plan and Procurement Enhancements</u>

Q. PLEASE DESCRIBE THE COMPANY'S RENEWABLE EXPANSION PLAN.

A. The 2022 IRP includes a long-term renewable expansion plan that proposes to add 6,000 MW of new renewable resources by 2035, more than doubling Georgia Power's previously approved portfolio of renewable resources. This long-term procurement plan is informed by the Company's expansion planning model, which determines the economically optimal amount of renewable resource additions. This plan continues the Company's measured and disciplined approach to the addition of cost-effective renewable generation.

The Company's renewable expansion study evaluates various renewable expansion plans based on scenarios with a range of potential carbon costs and fuel costs. Greater amounts of solar or renewable energy are deemed economically optimal in scenarios with higher fuel and emissions costs or lower-cost renewable procurements. The results of these scenario evaluations demonstrate the need for the Company's long-term resource procurement strategy to be adaptable to changing conditions in order to most efficiently support the economic procurement of resources. Thus, while the Company currently anticipates the need to add 6,000 MW of renewable resources by 2035, the Company proposes to monitor market conditions, System reliability needs, and customer expectations to guide the frequency, structure, and MW targets of future solicitations to ensure its long-term strategy remains in the best interests of all customers.

Q. HOW AND WHEN WILL THE COMPANY IMPLEMENT ITS PROPOSED BEST COST EVALUATION METHODOLOGY?

A. The Company will seek to procure energy from a certain amount of renewable resources by selecting a portfolio of the most valuable or best cost resources to fulfill the projected renewable energy need established in this IRP. As discussed in our direct testimony, the Company will continue to evaluate project economics during bid evaluations and proposes to cease automatically disqualifying bids for failing to exceed the Company's RCB adjusted avoided cost rate in the Company's RFPs (utility scale and distributed generation renewable resources). By making this change, the Company is introducing additional flexibility in filling the Company's renewable energy needs as identified by the renewable expansion plan analysis.

Importantly, this added flexibility does not undermine the Company's core principles of ensuring that it procures cost-effective resources that benefit customers. The Company, along with the Commission Staff and the IE, will leverage the information gained through the RFP process, such as actual bid prices (including the prices of Company-owned proposals), projected in-service dates, updated interconnection costs, and other market intelligence, to remain adaptable in procuring resources to meet the Company's renewable energy need. The Company, working with the Commission Staff and the IE, will determine the exact criteria and methods of evaluation, ranking, and selection as part of the Commission-approved RFP process. The DG RFP evaluation process will continue to differ from the Utility Scale RFP process to address differences in the two processes such as higher project volume and the complexity of distribution interconnection integration.

Renewable Procurements

Q. SOME INTERVENORS RECOMMEND NEAR-TERM PROCUREMENT OF 4,000 MW OF RENEWABLES. ARE THESE RECOMMENDATIONS SUPPORTED BY ANALYSIS?

A. No, these near-term procurement recommendations are not supported by any analysis. The GLSSA and APA industry panel suggests that the total amount of utility-scale solar procurement in this IRP should correspond to the total capacity approved in the 2019 IRP. However, the panel provides no support for its recommendation of 4,000 MW. Likewise, the Georgia Solar Energy Industries Association ("GSEIA"), Solar Energy Industries Association ("SEIA"), and Vote Solar panel recommends 4,000 MW of near-term new renewable procurement without any analytical support. The panel suggests that the Commission will arrive at the conclusion to accelerate the transition to clean energy after considering changes to Georgia Power's modeling assumptions.

Q. PLEASE EXPLAIN WHY 2,300 MW IS AN APPROPRIATE AMOUNT OF NEAR-TERM RENEWABLE PROCUREMENT.

A. The Company's recommended near-term procurement of 2,300 MW of new renewable resources to be online by 2029 is informed by the Company's AURORA expansion plan modeling across several natural gas price and carbon regulation scenarios. This amount represents an appropriate level of near-term procurement as the Company navigates the challenges of future renewable integration, such as transmission system limitations, market disruptions, and supply chain impacts, while remaining on track to achieve the Company's target of 6,000 MW by 2035. At this level of procurement, the Company will continue its steady approach to renewable resource procurement for the benefit of customers. Also, any amounts higher than 2,300 MW are unlikely to be achieved by the projected commercial operation dates due to the schedule for construction of transmission infrastructure and construction of solar resources. Additionally, due to the need to build transmission for south Georgia, the 2,300 is only likely achievable if the first utility scale procurement is targeted for north Georgia.

In addition, as part of the Company's triennial IRP process, Georgia Power will return in the 2025 IRP with recommendations based on updated information to determine the next tranche of renewable resources. While market challenges currently impacting the Company's renewable procurements (e.g., higher prices, longer timelines, supply chain issues) may subside over time, continuing the Company's measured and disciplined approach to renewable resources will enable to Company to better evaluate and navigate the impact of such issues for the time being.

Q. DOES THE COMPANY SHARE CONCERNS WITH STAFF AND INTERVENORS THAT THE NORTH GEORGIA RENEWABLE RFP MAY NOT BE FULLY SUBSCRIBED?

A. No, the Company believes it is premature to assume the market cannot deliver cost-effective north Georgia renewable resources. One of the benefits of competitive procurements is that the market is allowed to provide intelligence on market conditions through the bidding process, and accordingly the results of the north Georgia Renewable RFP should be not presumed until the RFP itself is completed. While the Company acknowledges that the north Georgia Renewable RFP may result in fewer bids than its last utility scale renewable RFP, the Company believes the north Georgia Renewable RFP can be successful. The Company is never assured when it issues an RFP that it will be fully subscribed, but the Georgia renewable market has proven its ability to adapt and deliver in the past and the Company is optimistic that it will continue to respond favorably going forward. Moreover, the Company has built additional flexibility into its procurements and will roll forward any MW not procured from the first RFP into the second RFP it plans to issue.

In addition, projects sited in south Georgia will almost certainly face significant interconnection and transmission related costs and delays, which will challenge all project timelines and feasibility from the start. Therefore, the Company believes that a north Georgia Renewable RFP is appropriate and has a better chance of success than an RFP that receives mostly bids located in south Georgia.

Q. GLSSA, APA, AND GSEIA, SEIA, AND VOTE SOLAR CLAIM THAT THE PROCESS BY WHICH THE COMPANY SEEKS FEEDBACK FROM

MARKET PARTICIPANTS IS NOT EFFECTIVE. PLEASE DESCRIBE THE COMPANY'S RFP PROCESS.

A. Georgia Power's RFP process is outlined in detail in the Commission's Rules. As explained by the IE panel during hearings, the Company's RFP process is a model for RFPs in other states. Georgia Power provides an opportunity to each interested participant at the conclusion of every RFP to provide feedback on prior RFP performance and to solicit feedback on lessons learned and improvements for future solicitations. The Company meets with bidders individually because each developer may have individual and confidential interests that are not fairly represented or may be lost when aligning priorities by a larger industry group. The Company solicits feedback before, during, and after each of its RFPs. The Company's RFPs are industry leading, and the Commission Rule-driven process allows feedback and participation from not only developers, but more broadly from all interested parties, during development of the RFP and associated PPAs, while also ensuring appropriate, fair, and transparent communication between all parties. Intervenors in the current IRP object primarily because not all their feedback is adopted. However, the decision not to adopt a developer's suggestion is made only after the suggestion has been fully vetted with the IE and the Commission Staff, who either agree with the Company's position to reject the developer's suggestion or note their disagreement at the time the RFP is submitted to the Commission for approval. Georgia Power is ultimately responsible for and must represent the interests of customers, which can often diverge from the interests of developers and independent power producers. The Commission should be wary of suggestions to modify the Company's RFPs from those who stand to benefit financially from those suggestions. While the Company appreciates and seeks out constructive feedback about its RFPs, it must balance that feedback with the best interests of customers. An RFP should be fairly administered and seek to obtain the most competitive prices on behalf of customers, and that is the way Georgia Power implements its RFPs.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED REVISIONS TO ITS DG INTERCONNECTION PROCESS.

A. The Company will continue to provide the necessary interconnection information on a project specific basis. As proposed, the Company will provide critical interconnection information through three complementary processes. First, the Company will make hosting capacity information available to help developers choose distribution feeders with the highest likelihood of hosting distributed generation. The hosting capacity tool will provide available capacity ranges on each of the Company's 2,356 distribution feeders. The hosting capacity tool will be developed over a three-year period beginning in the northwest portion of the state. Second, the Company will continue offering three tiers of year-round interconnection guidance that provide varying levels of detailed interconnection information to identify non-binding interconnection costs. Third, consistent with the Company's current practice, each DG project selected for participation in a DG program (whether competitive RFP or customer sited) will be individually studied to evaluate the System and facility conditions necessary to interconnect the facility and to identify the required interconnection costs.

Q. IS A SEPARATE REVIEW OF THE COMPANY'S DG INTERCONNECTION PROCESS NECESSARY?

A. No. The Company's existing interconnection process is overseen and reviewed by Commission Staff continuously as part of Georgia Power's DG RFP process.

Q. DOES THE COMPANY PROACTIVELY MODIFY ITS INTERCONNECTION PROCESS TO ADDRESS CONCERNS FROM PRIOR RENEWABLE RFPS?

A. Yes. Georgia Power proactively requests feedback from DG participants with each round of DG programs, and has enhanced the interconnection process in many ways, including: (i) offering year-round interconnection guidance and is planning to provide non-binding estimates to Tiers 2 and 3 to help developers understand potential costs before bidding; (ii) creating an Interconnection Facilities Site Plan to provide participants interconnection details and to clarify interconnection design in preparation for construction; (iii) developing the hosting capacity tool at the request of the market; (iv) creating construction guidelines to clarify interconnection construction standards, and (v) providing non-binding cost information to Staff regarding numerous interconnection costs.

Q. IS IT APPROPRIATE TO DEVELOP AND UTILIZE AN INTERCONNECTION COST MATRIX IN DG RFPS?

A. No. Interconnection costs are project and location specific and project interconnection costs can only be identified through interconnection studies. It would be inaccurate and potentially misleading to try to provide generic interconnection cost information to participating parties in the Company's DG programs. Inaccurate cost allocation and recovery would likely occur if an interconnection cost matrix was implemented due to the variability and range of interconnection costs for each DG project creating cost shifts between participants and non-participants. Georgia Power will be proactively providing non-binding estimates in Tier 2 and Tier 3 guidance moving forward to allow DG participants to make more informed decisions.

Q. IS IT APPROPRIATE TO MAKE A HOSTING CAPACITY TOOL PUBLICLY AVAILABLE?

A. No. Privacy and security issues related to sensitive grid information being publicly revealed is a major concern for the Company. If the hosting capacity tool is allowed to be openly accessed, sensitive Company and customer data could be available to the general population. This would make the grid unnecessarily vulnerable and could jeopardize customer reliability, resiliency, security, and confidentiality. DG participants have also shared feedback that public access may lead to landowners increasing their costs, which would make it more difficult to provide competitive pricing. Furthermore, it would likely have a negative impact on the Company's competitive position for customer choice projects. Georgia Power uses available capacity and other circuit level information in its discussions with potential customers looking to relocate or site in Georgia Power's service territory. Finally, if misused or taken out of context, the information provided in the hosting capacity tool could be misleading if applied in non-DG RFP siting applications. Therefore, Georgia Power's hosting capacity tool information should only be accessed by prospective RFP bidders through appropriate confidentiality requirements provided by the Company.

Q. WHAT IS THE BASIS FOR THE COMPANY'S PROPOSED LEVELIZED $7.50/KW ADDITIONAL SUM FOR PPAS RESULTING FROM ITS UTILITY SCALE AND DG RFPS?

A. The Company's proposed additional sum is based on the average additional sum amounts received by the Company over its last four utility scale renewable RFPs. The additional sum proposed by Georgia Power appropriately incentivizes the Company to competitively procure additional resources and fairly considers lost revenues, changed risks, and an equitable sharing of benefits consistent with Georgia's additional sum statute. Details of the calculation, which resulted in an average additional sum of $7.42 per kW, which was then rounded to $7.50 per kW, are shown in Table 2 below.

Table 2: Renewable Additional Sum Calculation

Solicitation	MW	Annual Additional Sum	$/kW
REDI I	510	$5,016,255	$9.84
REDI II	558.5	$2,942,736	$5.27
C&I REDI	177.5	$1,712,528	$9.65
2022/2023 RFP	970	4,763,536	$4.91
Total	2,216	$14,436,055	$7.42

Q. IS STAFF'S PROPOSED ADDITIONAL SUM METHODOLOGY COMPATIBLE WITH ITS RECOMMENDATION TO APPROVE BEST COST PROCUREMENT FOR RENEWABLE RFPS?

A. No. Staff proposes that the Company receive an additional sum equivalent to 8.5% of projected long-term energy savings provided by its procured renewable resources. An additional sum based on projected energy cost savings will not produce an additional sum for any resources procured above projected long-term MG0 avoided energy costs through best cost evaluation. The Company's proposed transition to a best cost methodology requires the adoption of a new additional sum methodology.

<u>Renewable Customer Subscription Programs</u>

Q. PLEASE DESCRIBE WHY THE COMPANY PROPOSES TO INCREASE THE COMMUNITY SOLAR RATES.

A. As approved, Georgia Power's Community Solar program ensures that participating customers are not subsidized by non-participants. The standard 'R' rate and General Service structure provides for the best opportunity to efficiently apply the Community Solar tariff. Based on current analysis, subscription cost should increase from $24.99 to $27.99 in order to prevent cost shifting to non-participating customers. At the current subscription price, Community Solar subscription fees will not cover the projected lost revenue in years 2023-2025.

Q. DOES THE COMPANY SUPPORT AN EXPANSION TO THE MONTHLY NETTING PROGRAM, CURRENTLY CAPPED AT 5,000 PARTICIPANTS?

A. No. The Company is still in the process of implementing the monthly netting pilot as it waits for the remaining applicants to notify the Company that their installations are complete. Once all 5,000 systems are installed, Georgia Power will be able to complete a comprehensive evaluation of the total program impacts to be shared with the Commission and Staff. The concerns already identified in the Company's direct testimony related to monthly netting, including: (i) cost shifting to non-participants; (ii) operational concerns with an increase in unplanned variable energy resources; (iii) the infiltration of aggressive and uninformed solar marketers misinforming customers; and (iv) noncompliance with the Company's rules, regulations, and program requirements for interconnection of behind the meter generation support the conclusion that the program not be expanded at this time. Additionally, interest in behind the meter solar continues at significant levels. Prior to the Renewable and Nonrenewable Resources ("RNR") Monthly Netting pilot, from 2016 through 2019, the Company saw an average of approximately 28 residential RNR-Instantaneous installations monthly. By comparison, in the ten months since the RNR-Monthly Netting cap was reached, the Company is receiving more than 400 behind the meter interconnection applications monthly, an indication that the rooftop solar market remains viable and active.

Q. WHEN WILL THE COMPANY COMPLETE ITS FULL ANALYSIS OF RATE IMPACTS TO PARTICIPATING AND NON-PARTICIPATING CUSTOMERS RELATED TO THE RNR MONTHLY NETTING PILOT?

A. In order to develop a full understanding of the impact of all participating customers across a 12-month period, which will take into account seasonal impacts on generation, as well as the specific characteristics of the entire portfolio of generation participating in the pilot, the Company believes it is appropriate to collect at least one year of data from all 5,000 customers participating in the monthly netting pilot before completing its analysis of the rate impacts to participating and non-participating customers. GSEIA Witness Lucas agreed that waiting for sufficient data was appropriate. As of June 1, 2022, there are 4,200 RNR-monthly netting customers online. The Company will continue to provide updates on this analysis to the Commission, as appropriate.

Q. DOES MONTHLY NETTING SHIFT COSTS TO NON-PARTICIPANTS?

A. Yes, because the 'R' rate recovers fixed costs through the energy charge, behind the meter solar generates a loss of revenue greater than the costs saved, which by definition leaves costs unrecovered from the participant that must then be recovered from other customers. Additionally, energy pushed back to the grid should be valued at the RCB adjusted avoided cost rate, an amount approved by the Commission that represents the value of this intermittent energy to the grid. Based on an initial review of data for customers enrolled for at least one year, the requirement of monthly netting to purchase these kWh at a rate closer to 12 cents per kWh, as opposed to the RCB adjusted avoided cost rate of approximately 3 cents per kWh is projected to increase costs for Georgia Power customers by more than $1.5 million annually, and these costs will be identified and recovered from customers in the upcoming Rate Case. As evidenced by multiple states grappling with the challenge of fairly unwinding retail net metering programs, there is no reason to knowingly create a future problem that will be difficult to solve. Georgia Power fully supports customers who wish to install rooftop solar, but it should be done without subsidization from other customers or overpayment for solar energy.

Q. DO MINIMUM MONTHLY BILLS AND CONSUMER PROTECTIONS AS PROPOSED BY GSEIA, SEIA, AND VOTE SOLAR MITIGATE THE COMPANY'S IMMEDIATE COST-SHIFTING AND OPERATIONAL CONCERNS ASSOCIATED WITH THE MONTHLY NETTING OPTION OF THE RNR PROGRAM?

A. No. Although these suggestions seem to confirm that GSEIA, SEIA, and Vote Solar understand that behind the meter solar can shift costs, none of the proposals mentioned in this IRP are supported by any analysis that shows they will prevent cost shifting.

RCB Framework

Q. WHY IS THE COMPANY RECOMMENDING REMOVAL OF THE GENERATION REMIX COMPONENT?

A. The purpose of the Generation Remix component was to capture the impact of future expansion plan costs that result from adding renewable resources to the System. This was appropriate when the Company's expansion plan contained no future renewable generic resource additions. Since the Company has adopted the AURORA model for the Resource Mix Study and expansion plan development, the expansion plan and associated costs already include the impact of adding renewables to the System. Therefore, a separate component to capture these costs is no longer needed in the RCB Framework.

Q. IS THE CAPITAL COST PORTION OF GENERATION REMIX ADDRESSED WITH THE RESOURCE MIX STUDY APPROACH?

A. Yes. The Resource Mix Study considers both capital and production costs for new resources, which include the addition of renewable resources over time. The model constructs expansion plans to minimize both capital and production costs. The capital cost portion of Generation Remix reflected the difference in expansion plan capital costs of the base case, which had no new renewables, and a case with the new renewables being evaluated. Since the expansion plan produced by AURORA now includes generic renewables, there are no longer two cases to compare. Neither the capital nor production cost portion of Generation Remix is relevant or needed with the Company's current Resource Mix Study modeling. Therefore, the Company has recommended the removal of the Generation Remix component from the RCB Framework.

Q. PLEASE EXPLAIN WHY STAFF'S RECOMMENDATION TO USE THE ECONOMIC CARRYING COST ("ECC") OF A COMBINED CYCLE

INSTEAD OF A COMBUSTION TURBINE FOR THE DEFERRED GENERATION CAPACITY COST COMPONENT IS INAPPROPRIATE.

A. Staff claims the Deferred Generation Capacity Cost should use the ECC of a combined cycle instead of a combustion turbine as an alternative to the previous Generation Remix process and because the combined cycle is "a primarily energy-focused resource" and a closer replacement for solar resources. (Tr. 403.) There are four primary reasons why this would be inappropriate.

1. As stated above, there are no missing capital costs attributable to the increase of renewables that are not already fully captured in the Resource Mix Study. Thus, it is unnecessary to create an alternative to calculating the previous Generation Remix component.

2. Staff's proposal is not only unnecessary, but it would replace an RCB component that could be either a cost or benefit depending on the study results with one that always ensures an additional benefit.

3. The existing Deferred Generation Capacity Cost component of the RCB Framework fully credits renewable resources for the capital cost of any capacity resources that the renewable resource defers. Additionally, the energy benefits attributable to solar as "a primary energy-focused resource" are fully accounted for in the Avoided Energy Cost component of the RCB Framework. Staff's recommendation would overvalue the resource and result in higher costs for customers.

4. Finally, the foundation of the RCB Framework is the long-accepted Peaker Theorem, which uses the capital costs of a peaking unit (a combustion turbine) and the System marginal energy costs as an efficient and close alternative to a full resource mix study and production cost analysis. If the Company were to use the ECC of a combined cycle as Staff suggests, it would no longer be appropriate to use the System marginal energy costs,

which contain hours when the marginal cost is set by peaking units or other units with higher marginal costs than a combined cycle. The Peaker Theorem is well established and a proven methodology to evaluate avoided costs. It should continue to be utilized as it currently is in the RCB Framework.

Q. STAFF CLAIMS THAT THE COMPANY HAS NOT PROVIDED ANY EVIDENCE OR DATA THAT THERE HAS BEEN AN ACTUAL INCREASE IN OPERATING RESERVES DUE TO THE INCREASE IN SOLAR PENETRATION. HAS THE COMPANY PROVIDED ANY EVIDENCE OR DATA?

A. Yes. The Company met with Staff on August 30, 2021 and reviewed actual data on the Southern Company System demonstrating how solar hourly ramping, solar ten-minute variability, and hourly solar forecast error have increased along with the increase in solar capacity from 2019 to 2021. While this data doesn't explicitly show how operating reserves increased, increases in operating reserves, such as regulating reserves and other load following reserves, are the tool that System operators use to mitigate the ramping and variability aspects of solar generation to ensure System reliability. The impact of integrating solar resources is not uniform. For example, there are days when multiple combustion turbines have been dispatched to manage the solar variability that depleted regulating reserves below an acceptable level. There are other days when the System can manage solar variability with fewer additional costs. In either case, there are no before and after costs captured by the System operators, such that actual integration costs can be compiled and presented to Staff. This is the reason why production cost models are important tools for estimating integration costs. The Renewable Integration Study uses the Strategic Energy and Risk Valuation Model ("SERVM"), the same stochastic reliability and production cost simulation model used in the Reserve Margin Study, to determine future integration cost that is a fair representation of the dynamic nature of solar integration.

Q. DOES THE COMPANY AGREE WITH STAFF'S RECOMMENDATION THAT RECS BE INCLUDED IN THE RCB FRAMEWORK?

A. The Company agrees that for IRP-approved procurements for which RECs are conveyed to the Company, a REC component could be included in the RCB Framework.

Q. HAS THE RCB FRAMEWORK BEEN LITIGATED IN PRIOR IRPS?

A. Yes. The Company filed numerous workpapers and technical volumes while responding to a substantial amount of data requests that reviewed the RCB Framework in significant detail in the 2016 IRP, 2019 IRP, and the current 2022 IRP. This information included illustrative calculations, results, and detailed descriptions of the framework. The RCB Framework information from IRPs was then implemented in subsequent RFPs to evaluate specific projects proposed in the applicable RFPs. Lastly, numerous intervening parties and Commission Staff provided detailed feedback on the RCB Framework in each IRP, which demonstrates the litigated nature of the RCB Framework. The Company continues to implement appropriate improvements to the RCB Framework based on this feedback and other additional information acquired by the Company.

X. ACCOUNTING TREATMENT AND COST RECOVERY

Q. WHY IS THE COMPANY REQUESTING THE RECLASSIFICATION OF NET BOOK VALUE AND UNUSABLE MATERIAL AND SUPPLIES INVENTORY EFFECTIVE WITH THE GENERATING UNITS' ACTUAL RETIREMENT DATES FOR ALL PROPOSED RETIREMENTS IN THIS CASE?

A. The Company is simply seeking accounting and ratemaking treatment to be effective at the date upon which the generating units are actually retired, which is consistent with the treatment of generating units previously retired through the IRP process.

Q. CAN THE COMMISSION APPROVE RECLASSIFICATION TO BE EFFECTIVE UPON THE GENERATING UNITS' ACTUAL RETIREMENT DATES IN THIS IRP AND DETERMINE THE PERIOD OF RECOVERY IN THE 2022 BASE RATE CASE?

A. Yes, for all the proposed generating unit retirements in this case, the Commission can approve the reclassification of the net book value and unusable material and supplies inventory into a regulatory asset account effective upon the actual retirement of those units in this IRP, and separately, in the 2022 Base Rate Case, determine the appropriate period over which the unrecovered amounts should be collected.

Q. DID THE COMPANY REQUEST ANY ACCOUNTING TREATMENT RELATED TO COST OF REMOVAL OR DISMANTLEMENT COSTS FOR THE PROPOSED RETIREMENTS IN THIS IRP?

A. No, these items will be addressed in a future Base Rate Case.

XI. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

STATE OF GEORGIA

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:

Georgia Power Company's	**)**	**Docket No. 44160**
2022 Integrated Resource Plan	**)**	

REBUTTAL TESTIMONY OF

AARON D. MITCHELL

June 8, 2022

REBUTTAL TESTIMONY OF

AARON D. MITCHELL

IN SUPPORT OF GEORGIA POWER COMPANY'S

2022 INTEGRATED RESOURCE PLAN

GPSC DOCKET NO. 44160

I. INTRODUCTION

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

A. My name is Aaron D. Mitchell. I am the Director of Environmental Affairs for Georgia Power Company ("Georgia Power" or the "Company"). My business address is 241 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308.

Q. DID YOU PREVIOUSLY PRESENT DIRECT TESTIMONY ON BEHALF OF GEORGIA POWER IN THESE PROCEEDINGS?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to respond to the testimony of the Georgia Public Service Commission ("Commission") Public Interest Advocacy Staff ("Staff") and various intervenors filed in Docket No. 44160 on topics related to the Company's Environmental Compliance Strategy ("ECS"). Due to the number of Parties filing testimony in this case and the limited time available to file rebuttal, my rebuttal testimony focuses on several key issues without attempting to address every issue raised in Staff or intervenor testimony. However, the fact that the Company may not respond to a particular position of Staff or an intervenor should not be construed as acceptance of such position.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. The ECS outlines the Company's plans to comply with all applicable state and federal environmental laws and regulations. The strategy enables Georgia Power to effectively address environmental compliance through the implementation of cost-effective and commercially available environmental control technologies. While Staff and intervenor testimonies indicate many areas of agreement with the ECS, various parties have raised questions regarding certain aspects of the Company's compliance plans, which are addressed further in my rebuttal testimony.

The 2022 ECS builds upon the ECS approved by the Commission in the 2019 IRP (Docket No. 42310), with updates focused on the investment and actions needed to comply with the Effluent Limitations Guidelines ("ELG") rule and both the federal and state coal combustion residuals ("CCR") rules for the Company's coal-fired power plants. The Company has supplemented the record in this proceeding through an updated ECS filed on April 22, 2022, and supplemental data request responses filed as new information relevant to the compliance strategy have become available. These updates confirm that while regulatory uncertainty will continue for the foreseeable future, it is imperative that the Company continue to take a long-term approach to planning decisions, including investing in appropriate environmental controls and making plans for fleet transition, to ensure that customers' needs are met.

The Company's ECS, as revised and supplemented by data request responses,[1] continues to support the strategy of retirement of nine units and installation of additional environmental controls at four units, which considers increasing environmental pressures, the continued cost-effectiveness of low- and zero-carbon resources, and future system reliability and resiliency needs. During these proceedings, the Company furthered its evaluation of membrane-based water treatment systems and confirmed, as the compliance

[1] Supplemented Data Requests include STF-LA-1-6, STF-LA-1-13, STF-JKA-2-20, STF-LA-4-8, STF-LA-4-9, STF-LA-4-11, and STF-LA-4-13.

pathway for Plant Scherer Units 1-2, the use of the Voluntary Incentives Program ("VIP"), which provides an additional three years to comply with the ELG rule.

While the CCR compliance strategy was approved in the 2019 IRP, the Company provided updates during these proceedings that specifically modified the plans for the Plant Wansley ash pond from closure in place to closure by removal. With the update of the Plant Wansley strategy addressed in the Company's April ECS update, the Company will now close 20 ponds by removal and nine in place. Staff and intervenors raised questions about the compliance plans for the ponds that will be closed in place in light of the Environmental Protection Agency's ("EPA") January 2022 site-specific determinations for certain closures in place outside of Georgia, where the agency indicated new interpretations of requirements and definitions commonly used across the industry. Although the EPA has recently announced new positions and regulatory interpretations, the requirements on which the Company's approved CCR compliance strategy are based remain unchanged. Georgia Power's CCR compliance plans are based on long-standing rule interpretations held by both industry and environmental regulators, and employ accepted engineering practices for closure designs that are consistent with the solid waste regulatory requirements on which the CCR rule is based. At all times, the Company's ash pond closure plans have been supported by sound engineering designs and certified by Professional Engineers with expertise in solid waste permitting and design. Further, the proven engineering controls the Company plans to implement at each ash pond that will be closed in place address the overall concerns stated in EPA's site-specific determinations through enhanced groundwater protection. The Company will continue to work with Georgia EPD as the permitting process continues for Georgia Power's ash pond closures and will keep the Commission informed through its semi-annual reporting.

Finally, Staff and intervenors also raise questions regarding the potential benefits and risks of the beneficial use of CCR. During these proceedings, the Company has progressed the evaluation of the Beneficial Use Request for Proposals ("RFP") that explores a market-driven approach to add value and potentially reduce compliance costs to, or long-term compliance requirements for, the benefit of customers. The Company recently signed its first contract resulting from the Beneficial Use RFP, whereby up to half of the ash stored at Plant Bowen's ash pond can be beneficially used. With this progress, the potential for significant closure cost savings and reduced long-term liability can begin to be realized. The RFP evaluation also demonstrates that not all beneficial use proposals and opportunities present savings, confirming that a market-driven approach is in the best interest of customers over the long term.

The 2022 ECS, April ECS update, and supplemental data request responses continue to support the Company's plans to comply with environmental laws and regulations consistent with the Company's commitment to supply clean, safe, reliable, and affordable energy to its customers. As such, the Commission should approve the updated ECS and related capital, operations and maintenance ("O&M"), and CCR asset retirement obligation ("ARO") costs and associated measures taken to comply with government-imposed environmental mandates.

II. ENVIRONMENTAL COMPLIANCE STRATEGY

Q. WHY IS IT IMPORTANT FOR THE COMMISSION TO REVIEW AND APPROVE THE ECS AND ASSOCIATED PLANS AND COSTS IN THESE IRP PROCEEDINGS?

A. The ECS describes the plans that the Company must implement at its facilities in order to comply with all environmental requirements. The ECS and the associated costs not only address actions needed to comply with upcoming deadlines for the CCR rule and the ELG rule, but also include the costs necessary to remain in compliance with other ongoing environmental requirements. Thus, these IRP proceedings have included detailed reviews of the ash pond closure plans and ELG compliance strategy, as well as the costs to continue to operate environmental controls, such as scrubbers, selective catalytic reduction systems, and baghouses, that were installed to meet environmental obligations.

The ECS must be reviewed and approved during these proceedings as a key component of the IRP as required by Commission Rule 515-3-4-.04(1)(c). The ECS outlines the

Company's environmental compliance plans and associated costs, and informs unit retirement studies and the Company's supply-side resource recommendations. While the rate case is the appropriate forum to discuss the <u>recovery</u> of the costs associated with environmental compliance, it is appropriate for the detailed review and approval of the ECS and related costs to be completed within the IRP proceedings.

Q. WHAT UPDATES HAS THE COMPANY PROVIDED RELATED TO THE ECS SINCE THE DIRECT HEARINGS OR IN RESPONSE TO STAFF AND INTERVENOR TESTIMONY?

A. As committed to in the ECS as originally filed in January 2022, the Company has provided updated and supplemental information for the Commission's review. This information includes the details of the revised ash pond closure strategy at Plant Wansley and the results of additional membrane-based water treatment technology evaluations at Plant Scherer for ELG compliance. In this testimony, the Company explains its recommendations related to these updates and responds to Staff and intervenor testimony on CCR compliance and CCR beneficial use.

III. <u>ELG COMPLIANCE STRATEGY</u>

Q. WHAT SPECIFIC ASPECTS OF THE ELG COMPLIANCE STRATEGY HAVE BEEN PRESENTED TO THE COMMISSION DURING THESE IRP PROCEEDINGS?

A. The Company has already implemented the previously approved compliance strategy for several aspects of the ELG rule. As such, the updated strategy for complying with the flue gas desulfurization ("FGD") wastewater effluent requirements as outlined in the 2020 ELG rule is presented to the Commission in the 2022 ECS. This strategy includes the Company's election of the cessation of coal combustion by December 31, 2028 compliance pathway for the proposed retirement of Plant Bowen Units 1-2, Plant Scherer Unit 3, Plant Wansley Units 1-2, and Plant Gaston Units 1-4. In addition, the strategy provides for the installation of controls at Plant Bowen Units 3-4 and Plant Scherer Units 1-2.

Q. PLEASE EXPLAIN THE PLANT BOWEN UNITS 3-4 ELG COMPLIANCE STRATEGY AND RELEVANT CONSIDERATIONS FOR PLANT BOWEN UNITS 1-2.

A. The Company's election to install controls at Plant Bowen Units 3-4 recognizes that the transmission system cannot reliably accommodate the retirement of all units at Plant Bowen by December 31, 2028. As a result, Plant Bowen Units 3-4 must pursue compliance with the generally applicable effluent limits through installation of physical-chemical-biological ("PCB") FGD wastewater treatment by December 31, 2025. On the other hand, transmission system updates are possible to support the retirement of Plant Bowen Units 1-2 by December 2028. After evaluating existing and future pressures, the Company determined that Bowen Units 1-2 face economic challenges for continued long-term operation.

If the Commission does not approve the December 2027 retirement date for Bowen Units 1-2, the proposed ELG compliance strategy for Bowen Units 3-4, which is driven by the site-specific needs for wastewater management, will nevertheless accommodate all the operating units at the plant (*i.e.*, Units 1-4). The controls necessary for ELG compliance are in addition to existing common water treatment systems at Plant Bowen. Wastewater from the FGD scrubbers of all four units are combined into common infrastructure and either recycled or treated by the existing water treatment system. Elimination of two units at Plant Bowen does not materially change the overall water treatment needs due to the decreased evaporative water loss associated with operation of the scrubbers and the difference in environmental control configuration between Plant Bowen Units 1-2 and Units 3-4. These factors cause variations in the quality and volume of water that result in a design, size, and cost of the ELG control system that does not change with the retirement or continued operation of Plant Bowen Units 1-2.

Q. PLEASE EXPLAIN THE PLANT SCHERER UNITS 1-2 ELG COMPLIANCE STRATEGY AND RELEVANT UPDATES RECENTLY PROVIDED TO THE COMMISSION.

A. As described in the 2022 ECS, the Company evaluated two options for FGD wastewater compliance for Scherer Units 1-2. One option uses the PCB treatment approach with compliance by the end of 2025. The second option uses membrane-based water treatment systems and the VIP pathway with compliance by the end of 2028. As discussed in the ECS as filed in January 2022, Plant Scherer is in a unique position to explore membrane-based FGD wastewater treatment due to technology advancements, site-specific factors, and the new VIP pathway available in the 2020 ELG Reconsideration Rule.

The Company recently furthered its evaluation of the membrane-based treatment systems, and the results of the additional evaluation were filed at the Commission on May 27, 2022, through the submittal of supplemental data requests.[2] The updates confirm that, for Plant Scherer specifically, membrane technology is the compliance pathway for ELG compliance versus the PCB option that was originally planned. Costs are projected to be comparable for both options, while the membrane technology will perform a higher level of treatment to meet more stringent compliance limits for certain FGD wastewater constituents and provide for greater operational flexibility for the generating units.

Q. DOES THIS UPDATED INFORMATION CONFIRM THE COMPANY'S PLANS FOR ELG COMPLIANCE AT PLANT SCHERER UNITS 1-2?

A. Yes. As discussed in the ECS, because the evaluation of the membrane-based water treatment system shows appropriate technical performance, reliability, operational flexibility, and cost when compared against the physical-chemical-biological controls, the Company intends to install the membrane-based system for Plant Scherer Units 1-2 in coordination with the facility's co-owners. While the VIP pathway requires Scherer Units 1-2 to achieve lower scrubber wastewater effluent limits to comply with the ELG rule, the

[2] Supplemented Data Requests include STF-LA-1-6, STF-LA-1-13, STF-JKA-2-20, STF-LA-4-8, STF-LA-4-9, STF-LA-4-11, and STF-LA-4-13.

recent evaluation shows the membrane-based treatment option is expected to be able to meet these requirements at costs comparable to PCB treatment. One of the primary benefits to selecting this option is that the VIP pathway affords an additional three years to comply. With this additional time, the Company will have a better opportunity to adjust to the dynamic regulatory environment, leverage its research and development, and design and update the strategy or pursue retirement should conditions change.

IV. CCR COMPLIANCE STRATEGY

Q. WAS THE USE OF ASH PONDS FOR WATER TREATMENT BY GEORGIA POWER APPROPRIATE AND IN COMPLIANCE WITH THE RULES AND REGULATIONS THROUGHOUT THEIR LIFECYCLE?

A. Yes, Georgia Power has operated ash ponds as wastewater treatment systems in compliance with all requirements. Contrary to the testimony of Sierra Club witness Mark Quarles (Quarles Pre-filed Direct Testimony at 17-18.), ash ponds have been considered industry standard for years. In fact, from 1982 until 2015, EPA determined that ash ponds were the best practicable control technology for wastewater treatment under the National Pollutant Discharge Elimination System ("NPDES") permitting program at coal-fired power plants. Through the NPDES permitting program, EPD and EPA identified and regulated the ash ponds as wastewater treatment systems for decades.

Q. WHAT ASPECTS OF THE CCR COMPLIANCE STRATEGY ARE PRESENTED TO THE COMMISSION DURING THESE IRP PROCEEDINGS?

A. While the CCR rule was finalized in 2015 and the Company's compliance strategy was presented to the Commission and approved through the 2019 IRP, Georgia Power provided relevant updates on regulatory matters in the 2022 ECS and updated the strategy for the Plant Wansley ash pond due to a new compliance option available with the proposed retirement of the Plant Wansley Units 1-2 in the IRP. While EPA continues to consider future CCR rule revisions and has recently announced new positions and regulatory interpretations, the requirements on which the Company's approved CCR compliance strategy are based remain unchanged.

Q. WHAT UPDATED INFORMATION HAS THE COMPANY PROVIDED ON THE CCR COMPLIANCE STRATEGY SINCE THE FILING OF THE IRP?

A. Following discussion during the Company's direct hearings, on April 22, 2022, the Company filed supplemental information[3] and updated its ECS to reflect the change in compliance strategy for the Plant Wansley ash pond from closure in place to closure by removal, provided the Commission approves the retirement of Plant Wansley Units 1 and 2 during the IRP proceedings. In addition, the Company filed supplemental information for relevant data requests and updated the CCR ARO table in the Selected Supporting Information section of Technical Appendix Volume 1 to reflect the closure by removal plan. The Company's assessment confirms that Plant Wansley has a unique opportunity to maximize the use of the existing landfill asset, manage construction and operational risks associated with the current closure in place design, and provide for potential future market-driven beneficial use of the ash by moving to a closure by removal strategy.

Q. PLEASE DESCRIBE EPA'S NEW POSITION AND PROVIDE AN UPDATE ON ANY ADDITIONAL GUIDANCE PROVIDED BY THE AGENCY SINCE JANUARY.

A. In January 2022, the EPA published proposed determinations for the CCR rule Part A for nine facilities across the Midwest and Northeast that had requested extensions for compliance with the federal CCR rule. In these facility-specific determinations, the EPA included new positions on the 2015 CCR Rule for closure in place performance standards and groundwater monitoring networks, statistical analysis methods, alternate source demonstrations, and groundwater corrective action. While EPA and Georgia EPD are having ongoing discussions regarding these activities, EPA has not provided additional guidance specific to the Georgia Power closure plans at this time.

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[3] Supplemented Data Requests include STF-LA-1-8, STF-LA-1-18, and STF-LA-4-5.

Q. PLEASE DESCRIBE HOW THE GAVIN PLANT CCR CLOSURE PLANS REFERENCED IN EPA'S JANUARY 2022 DETERMINATIONS AND IN INTERVENOR TESTIMONY RELATE TO GEORGIA POWER'S CLOSURE PLANS.

A. Georgia Power's closure plans were not reviewed in and are not subject to EPA's January 2022 determinations for the Gavin Plant, which is located in Ohio. The EPA specifically disapproves of the Gavin Plant's extension request due to a lack of specificity in how the closure plan will address groundwater protection. Notably, Georgia EPD has required detailed information on the CCR rule performance standards to be submitted on each of Georgia Power's closure in place plans as a part of the state's federally approved CCR permitting program. In contrast to the information allegedly lacking in the Gavin Plant's plans, Georgia Power's information under review by Georgia EPD includes details on engineering controls, which EPA specifically mentions in the Gavin Plant determination as a way to enhance groundwater protection, at each closure in place site to meet the federal performance standards.[4] Ultimately, Georgia EPD oversees the CCR permitting program and is responsible for making compliance determinations and issuing permits for all CCR units in Georgia.

Q. DO THE COMPANY'S CLOSURE IN PLACE PLANS MEET THE REQUIREMENTS OF THE FEDERAL AND STATE CCR RULES?

A. Yes, Georgia Power's closure plans are designed to comply with both the federal and state CCR rules. The Company's plans for closure in place units include engineering controls that are site-specific to address the unique factors at each location. Depending on the needs of the site, proven engineering designs are developed in consultation with third party experts using long-standing rule interpretation held by both industry and environmental regulators. These industry- and agency-accepted engineering practices are consistent with solid waste regulatory requirements, on which the CCR rule is based. The plans are

[4] Proposed Denial of Alternative Closure Deadline for General James M. Gavin Plant, Environmental Protection Agency (Jan. 25, 2022) at 47, *available at* https://www.regulations.gov/document/EPA-HQ-OLEM-2021-0590-0002.

designed to enhance groundwater protection, improve closure effectiveness, and minimize future maintenance.

Q. HOW HAS THE COMPANY ADDRESSED THE CLOSURE IN PLACE PERFORMANCE STANDARDS WITH ENGINEERING CONTROLS?

A. The use of appropriate proven engineering methods that are suitable for each closure are critical to meeting the CCR Rule Performance Standards for closure in place plans. Georgia EPD has communicated the importance of these measures and is reviewing all the engineering controls planned at Georgia Power sites through the CCR permit application review process. Examples of these engineering controls include:

- Consolidating the ash to minimize the environmental footprint;
- Subsurface walls (slurry walls) designed to reduce the flow of groundwater through a CCR unit;
- Surface cover systems designed to minimize the infiltration of stormwater into a CCR unit; and
- Subsurface hydraulic control systems installed within or around a CCR unit designed to remove water from within a CCR unit.

Q. HAS EPD MADE ANY DECISIONS ON CCR PERMITS BASED ON EPA'S NEW POSITIONS ANNOUNCED IN JANUARY 2022?

A. No, Georgia EPD has not made any new determinations or revised any existing determinations on closure in place CCR permits at this time. EPD has issued one final and one draft closure in place permit. In response to EPA's new positions, Georgia EPD and EPA have met several times since January and discussions between the two agencies are ongoing. As previously discussed, the Company's closure in place plans include robust, site-specific designs and proven engineering controls that were developed in conjunction with third party experts to meet the Performance Specifications of the CCR rule. The Company will update the Commission if Georgia EPD issues any determinations that change the compliance strategy for any CCR units.

Q. WHAT ACTIONS MUST THE COMPANY TAKE ON ITS CCR COMPLIANCE STRATEGY WHILE EPD AND EPA DISCUSSIONS ARE ONGOING?

A. With strict compliance deadlines for the closure of 29 ash ponds across the state, the Company must continue work on ash pond closures to meet the requirements in the federal and state CCR rules. Consistent with past practice, the Company plans and sequences work strategically to ensure closure progress continues as required *in the shortest amount of time consistent with recognized and generally accepted good engineering practices* (40 C.F.R. 257.102(d)(1)(v)), while also adjusting the schedule for certain activities to mitigate risk where possible. For example, where project work is underway or near complete, closure activities must continue to appropriately manage construction and environmental risk associated with safety, weather, compliance, and costs if the Company were to slow or stop work. For projects where primary closure construction work is not fully underway, to the extent possible and in light of mandatory closure timelines, the Company is mitigating risk with the sequencing of work to focus on site preparation, dewatering, and other construction activities that must be completed regardless of the closure option. These actions allow for more flexibility to incorporate any updates in regulation into closure plans.

V. <u>BENEFICIAL USE</u>

Q. HOW CAN BENEFICIAL USE OF CCR ENHANCE THE CCR COMPLIANCE STRATEGY TO THE BENEFIT OF CUSTOMERS?

A. Beneficial use of CCR can benefit the closure plans for CCR units in certain circumstances, by reducing the amount of ash that must be closed and the associated construction, by reducing the footprint or long-term monitoring requirements of the CCR unit, and by producing sales to offset closure costs. However, the potential benefits are highly site-specific, and beneficial use can also add costs or complexity to the closure plans in certain cases. Recognizing these factors, the Company has solicited market competition and pursued an in-depth evaluation process to assess beneficial use opportunities that are expected to deliver the most value to customers.

Q. WAS TESTIMONY FILED BY STAFF AND INTERVENORS GENERALLY SUPPORTIVE OF CCR BENEFICIAL USE?

A. Yes. The testimony regarding beneficial use was generally supportive of the Company taking advantage of cost-effective opportunities to pursue beneficial use. However, Staff witnesses Ralph Smith and Rob Trokey indicated concerns with beneficial use resulting in net overall cost (Tr. 357), while Sierra Club witness Mark Quarles described beneficial use as a means to fund ash management practices. (Quarles Pre-filed Direct Testimony at 7.) This range of perspectives reinforces the Company's approach to balance potential benefits with risk in order to identify solutions that are in the best interest of customers.

Q. HOW HAS THE COMPANY BALANCED THE POTENTIAL BENEFITS WITH THE MARKET RISKS OF BENEFICIAL USE?

A. Georgia Power has decades of experience with CCR beneficial use associated with the use of production ash in the concrete market. Through this experience, Georgia Power marketed 85% of production CCR in 2021, demonstrating the Company's ability to effectively recycle CCR within the regional market. With the available ash supply from active coal fired generation expected to decrease over time, there is a projected gap between market demand and the supply of ash in the future. However, as with any commodity, there are inherent market risks that could impact the assumed volumes and realized benefits of beneficial use in the future. While it is not possible to eliminate these risks altogether, the Company is leveraging a robust framework to mitigate these risks where possible and pursue opportunities that are expected to add value to customers. Specifically, the Company is:

- Pursuing a market-driven approach for its ash pond portfolio through a Beneficial Use RFP process. Georgia Power's market-driven approach for the beneficial use of stored coal ash is superior to a mandated approach because it is informed by proposals from real market participants, currently available technologies, and bidder expectations for the quantities of ash that are realistic to place into the market without causing downward pressure on the market economics.

- Exploring new and emerging beneficial use technologies and future opportunities through the Ash Beneficial Use Center located at Plant Bowen as discussed in the Company's ECS.

- Utilizing contractual mechanisms to ensure vendor performance for the construction of any needed infrastructure, operations, and market volume commitments.

Q. HAS THE COMPANY MADE PROGRESS ON THE BENEFICIAL USE RFP?

A. Yes, the Company is under contract with a vendor for beneficial use of CCR at Plant Bowen and this contractual agreement has been made available to the Commission. Over the next 15 years, the Company expects to process and market up to 9 million tons of the ash from the approximate 20 million tons in the ash pond at Plant Bowen for the ready-mix concrete market. This arrangement will reduce long term liability with a smaller final ash pond closure footprint to maintain in post-closure care, produce ash sales to offset ash pond closure costs, and expand the Company's ash pond beneficial use efforts to include the ready-mix concrete market.

Q. WHAT ARE THE COMPANY'S NEXT STEPS FOR BENEFICIAL USE?

A. The Company will continue with the implementation plans for the recently executed contract at Plant Bowen. This activity includes the construction of ash processing infrastructure at the site by early 2024 with ash processing and active marketing to immediately follow to complement the ongoing ash pond closure activities. Additionally, the Company continues to focus on optimizing beneficial use of production ash from the active coal plants, evaluate potential opportunities to harvest ash from ash ponds and landfills with the ongoing Beneficial Use RFP, and remain flexible to take advantage of beneficial use opportunities when they are available in the future.

VI. CONCLUSION

Q. WHAT IS GEORGIA POWER REQUESTING OF THE COMMISSION IN THE 2022 IRP AS IT RELATES TO THE ECS AND ENVIRONMENTAL COMPLIANCE?

A. The Company seeks the Commission's approval of the updated ECS and related capital, O&M, and CCR ARO costs and associated measures taken to comply with government-imposed environmental mandates as set out in the ECS in Technical Appendix Volume 2 and the ECCR and CCR ARO tables in the Selected Supporting Information section of Technical Appendix Volume 1 and supplemental data request responses.[5]

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[5] Supplemented Data Requests include STF-LA-1-6, STF-LA-1-13, STF-JKA-2-20, STF-LA-4-8, STF-LA-4-9, STF-LA-4-11, STF-LA-4-13 and STF-LA-1-8, STF-LA-1-18, STF-LA-4-5, and STF-LA-4-26.

BY MR. HEWITSON:

Q Mr. Grubb, on June 13th, 2022, did the Georgia Public Service Commission Public Interest Advocacy Staff and Georgia Power Company enter into a stipulation regarding this Docket and Docket No. -- and Docket No. 44161?

A (Witness Grubb) Yes, we did.

MR. HEWITSON: Madam Chair, I would like to identify the stipulation as Georgia Power Exhibit 20 and have it admitted into the hearing record.

MADAM CHAIR PRIDEMORE: So moved.

(GPC Exhibit 20 was admitted into evidence.)

MR. HEWITSON: And, for the record, I am pleased to announce that the Commercial Group and the Georgia Association of Manufacturers have each signed onto the stipulation.

Chair Pridemore, with your permission, I'd like Mr. Grubb to summarize the supply side portion of the stipulation.

MADAM CHAIR PRIDEMORE: Go ahead.

WITNESS GRUBB: Thank you. Good morning, Commissioners.

On Monday, June 13th, 2022, the Commission's Public Interest Advocacy Staff filed a stipulation signed by the company and PIA staff. The Commercial

Group and Georgia Association of Manufacturing have also signed onto the stipulation. On behalf of the stipulating parties, we ask that the Commission approve the stipulation as a reasonable resolution of Georgia Power's 2022 IRP and DSM cases.

The stipulation continues the long-standing history of collaboration and compromise between the company and PIA staff and takes into account many of the issues raised by intervenors in this proceeding.

The stipulation is a fair and balanced settlement of Georgia Power's 2022 IRP and DSM cases. As with any settlement, no single party received everything they advocated for or requested, and compromises were made on many complex issues.

However, the stipulating parties worked to look beyond single issues and come to an agreement focused on the overall outcome and impact of the issues to our customers. As such, the stipulation as a whole represents a fair and balanced outcome of these proceedings, which we believe will provide significant benefits for our customers.

In the interest of time, instead of addressing every provision in the stipulation, we will take this opportunity to highlight the stipulated items that received significant attention during these proceedings.

The company's generation fleet continues to evolve with respect to the supply side plan. Plant Wansley Units 1, 2, and 5A, and Plant Boulevard Unit 1 will be decertified and retired by August 31st, 2022.

Plant Scherer Unit 3, Plant Gaston Units 1 through 4 and Unit A will be decertified and retired by December 31st, 2028. Continued operation of these units is no longer in the best interest of customers, despite these plants having served customers well over the past several decades.

Although the company's unit retirement study supports the retirement of Plant Bowen units 1 and 2, PIA staff's analysis determined that the retirement of Plant Bowen Units 1 and 2 is a close call. The stipulating parties agree that the decision of when to retire Bowen Units 1 and 2 between December 31st, 2027 and December 31st, 2035 is a positive decision for the Commission.

The stipulating parties agree to the company's plan to install effluent limitation guidelines or ELG controls for Plant Bowen Units 3 and 4 and Plant Scherer Units 1 through 2.

The stipulating parties recommend the

Commission grant the certificate of public convenience and necessity for the six long-term capacity power purchase agreements entered into as a result of the 2022 through 2028 capacity RFP as replacement generation for the retired units. The stipulating parties further agree that the additional sum for these capacity PPAs be set at $3 per kilowatt year.

The transmission projects necessary to accommodate the units proposed for retirement in this IRP should be approved. The company agrees to develop and file an annual transmission update report with the status, schedule and budget for each transmission project in the company's unit retirement study and selected supporting information in technical appendix Volume 1. The company agrees to identify alternative solutions considered and the corresponding costs and benefits for such alternatives.

The stipulating parties agree to the approval of the North Georgia Reliability and Resilience Action Plan, except for projects from the utility scale RFP being limited to projects sited in North Georgia.

The company also agrees to update Commission staff twice a year on the status of the North Georgia Reliability and Resilience Plan and the strategic transmission projects needed to support the retirement of Plant Bowen Units 3 and 4.

Although the stipulating parties acknowledge the potential value of energy storage systems to the reliability of the electric system, the company's request to develop, own, and operate 1,000 megawatts of energy storage systems is not approved in this IRP. Nevertheless, the company is provisionally authorized to develop, own, and operate the McGrau Ford battery facility.

The company agrees to provide the final McGrau Ford battery facility engineering procurement and construction agreement to the Commission for approval and to establish a deemed certified amount for the project.

The company will continue to use the 26 percent system winter target reserve margin for seasonal planning purposes until such time as a winter and target reserve margin is agreed to by staff and the company and approved by the Commission. The company may propose resource additions to meet a winter need in the next IRP, and the Commission can determine at that time what the appropriate target reserve margin is for winter and whether such additional capacity is needed.

The company's environmental compliance strategy, including the update to the company's plans to address coal combustion residuals and the company's ash ponds and landfills is approved. The stipulating parties acknowledge that projected CCR compliance costs have been reviewed, that the Commission is not approving any costs, and that it is not necessary for the Commission to approve a specific budget for CCR compliance at this time. The company will seek the recovery of such costs in the 2022 rate case.

The company will continue to file semi-annual reports to keep the Commission updated on CCR compliance efforts. And the company agrees to file a final report on the results of the beneficial use RFP, including updates to the company's cost-benefit analysis, justifying its beneficial reuse plan.

The ECCR cost information and CCR ARO tables are acknowledged and the recovery of the ECS plan costs will be determined by the Commission in the upcoming rate case. The company will conduct an all-source RFP for capacity needed in the '29 to 2031 time frame with specific resource eligibility requirements to be approved by the Commission in accordance with the Commission's RFP process.

As provided in the stipulation, Georgia Power will procure energy from a total of 2,100 megawatts AC of new utility-scale renewable resources, sized greater than 6 megawatts, through two RFPs. The first RFP will target 1,050 megawatts of renewable resources with the remaining megawatts needed to reach the 2,100 megawatt targeted sought in the second RFP.

All renewable projects procured to the company's utility-scale renewable RFPs will be required to operate on automatic generation control. The Commission staff and company will determine the appropriate methodology to value such resources before the next utility-scale renewable RFP is issued.

All 2,100 megawatts of utility-scale resources will be available for commercial and industrial customer subscription pursuant to the company's clean and renewable energy subscription program or caterers through the prescribed customer carve-outs included in the company's filing.

For the distributed generation procurement, Georgia Power will seek to procure from 200 megawatts of renewable resources, sized 250 kilowatts up to 6 megawatts AC. Georgia Power will issue one DG RFP with two solicitation periods each seeking 100 megawatts of distributed generation solar resources. Contract terms -- contract terms for the distributed generation projects may be up to 35 years.

The stipulating parties agree that the company's evaluation and selection of renewable resources in future utility-scale and distributed generation renewable procurements should be based on a best cost approach. The Company, PIA's staff and independent evaluator will determine the exact criteria and methods for this best cost methodology as part of the Commission-approved RFP process.

The renewable cost-benefit framework and renewable integration studies are approved for future renewable procurements as modified by the stipulation. The company and Commission staff agree to meet to determine how to value a REC component and agree to use the effective load-carrying capability method when determining capacity value or procurement activities.

The additional sum for utility-scale and distributed generation resources procured pursuant to this RFP will be set at a levelized $4 per kilowatt year.

In an effort to improve the interconnection of distributed generation projects, the company's proposed hosting capacity tool is approved as modified by the stipulation. The company and Commission staff will also initiate a review of Georgia Power's distributed generation interconnection process prior to the next DG RFP to consider modifications and to establish a distribution interconnection cost matrix.

The company's other proposed new or modified renewable programs, including the existing resource retail REC retirement, flex REC, simple solar, and community solar are approved, except for the proposed rate provisions which will be reviewed and approved in the 2022 rate case.

The stipulating parties agree to increase investments for hydro units at Plant Sinclair and Plant Burton and all future hydro modernization requests will include a cost-benefit analysis and an economic comparison of alternatives. The DER local reliability and constraints pilot at four locations, the tall wind demonstration, and integrated hydrogen microgrid pilots are approved and subject to semi-annual filing requirements.

The stipulation represents a positive outcome for our customers. By compromising on many of the contested matters in this IRP, the stipulating parties considered many perspectives between the differing interests requested -- represented in this proceeding and struck a fair balance that ensures the company can continue to provide safe, clean, reliable and affordable electric service to customers now and well into the future. Thank you.

MR. HEWITSON: Thank you, Mr. Grubb.

Madam Chair, the witnesses are available for questions from the Commissioners, as well as cross-examination.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Hewiston.

Questions from Commissioners?

(No response.)

MADAM CHAIR PRIDEMORE: Okay. I have a few.

So the stipulated agreement has a -- has a pretty quick date to retire Wansley 1 and 2. I've been out to Wansley recently. I've seen the plant firsthand. I've seen its age and recognize what would need to be done to that plant -- to that whole facility for it to stay operating.

I guess my concern is more of a reliability concern. Each of those Wansley units is roughly 466 megawatts. What are we replacing that with by August of this year?

WITNESS GRUBB: So, Madam Chair, currently we have enough resources to be above our target reserve margin, even with the retirement of Wansley.

MADAM CHAIR PRIDEMORE: Okay.

WITNESS GRUBB: And so immediately the rest of the fleet will be there to serve customers.

Eventually you get to where that does impact your need. And part of the capacity RFP, six PPAs that we procure -- or requesting would replace part of that Wansley. But mostly it's because right now we're above that target reserve margin and we can -- we can retire them and stay above that target for the next four or five years.

MADAM CHAIR PRIDEMORE: Let's say we have an incredibly hot summer and it extends through October. Do we still have enough capacity to meet the needs?

WITNESS GRUBB: We do.

MADAM CHAIR PRIDEMORE: Okay.

All right. I had a question about -- give me a second to find it. On line 4 of the stipulated agreement, towards the end, it says: The units may be retired separately or together. This is talking about Bowen 1 and 2.

Should either or both units operate beyond December 31st of 2027, all reasonable and prudent costs associated with their continued reliable operation will be recovered by the company.

Is that an assumption that you would come in with those costs in a rate case, or is the assumption that it would be fully recovered because the Commission asked for the long extension?

WITNESS GRUBB: So we're not asking for any specific recovery there. What we're simply noting is that we've had spending limits at Bowen 1 and 2 since the last IRP. And we are able to glide past those budgets through 2027 and maintain those -- those lower costs if we're going to retire those units.

If we're not going to retire those units, then we need to invest more capital in those units than we will have otherwise. And so it will follow through the normal cost recovery processes through the rate cases and ASR. The point was really just to say there will be an increase spend there because we don't have that end date that we have been planning.

MADAM CHAIR PRIDEMORE: And we have determined that the ELG cost considerations on all the coal units would be spread equally across each unit on an operating plant? So like in the case of Scherer, that's for all four. In the case of Bowen, that's for all four, et cetera.

MR. MITCHELL: That's right, Madam Chair.

MADAM CHAIR PRIDEMORE: And my last question for now is on page 8 of the stipulated agreement. You go to the 29th line, but it's on the -- it's on the second page of it.

WITNESS GRUBB: Yes, ma'am.

MADAM CHAIR PRIDEMORE: So about midway through: In addition, the company and staff will discuss staff's suggestions to modify the deferred generation capacity cost component to use the economic carrying costs to ECC of a, quote, combined cycle unit instead of a combustion turbine.

Explain to me why the change.

WITNESS WEATHERS: Madam Chair, I can address that.

So the renewable cost-benefit framework that we have in place, the version in this IRP has some modifications. So one of those is related to the component called generation remix. It was previously there when we had -- did not have any new generic renewables in our expansion plan.

So when you introduced renewables, there's a cost difference between one plan without them and the plan with them. And so with the new model, we don't have -- we do have generic renewables in the plan. And so we're proposing to not have the generation remix portion of it.

Well, staff -- staff's position was that there's come capital costs and they -- and they wanted to address those with the change from value capacity at the cost of a combustion turbine or a peaker unit to a combined cycle. So the company staff had disagreement there. So we're going to agree to meet with staff after the hearings to discuss that issue.

MADAM CHAIR PRIDEMORE: Okay. Go ahead, Commissioner.

COMMISSONER McDONALD: In today's world, and, of course, this IRP has been formulated over a year getting to where we are today, but the cost of natural gas that has surfaced in the last year, when you compare that cost of running a combined cycle of whatever today with a coal unit, does this not give you concern to want to readdress this stipulation in regards to some of the things that the Chairperson asked about with Bowen and closing these coal plants?

When you turn on the news at 5:00 this morning and you see where Germany is starting up their coal plants big time because they've closed their nuclear plants. And we know that they don't have natural gas like we have in this country and we've addressed, does this not give you a little concern knowing that -- what you know today, not what you knew six months ago when you were developing this IRP, and what the outlook is in the next 18 months that we see from an energy standpoint in this nation?

Does it give you a little heartburn like it does me?

WITNESS WEATHERS: It's a good question, Commissioner. I think it is important to continuously consider the price of fuel in all decisions, particularly with natural gas and coal.

It is true, natural gas prices have been elevated. Coming out of the pandemic, the demand for natural gas or power generation business and throughout the economy picked up, but the supply lagged.

So it was not as quick to introduce new production. So prices rose. And that was made even higher through the ongoing war between Russia and Ukraine in Europe. So those have constrained supply and increased demand even further.

But it's also -- when we're looking at planning decisions, so decisions that are going out to the future and purchase power agreements and coal decisions several years out, except for Wansley, we're looking at -- the markets expect prices to come back down after next winter, so the winter of '23, '24, that December/January, back down below $4 in the spring and then below $5 on an annual basis.

The Energy Information Administration that we use for our long-term gas prices on a long-term basis, they do expect prices to come back down. The fundamentals of the natural gas market are still sound. There's still supply in the ground.

They expect to be able to extract that and deliver that to our customers at relatively low prices. In the short term, the EIA expects natural gas prices to come back down next year, as well.

Additionally, coal markets have seen volatility, as well. If we look at -- you would think that maybe with higher natural gas prices coal prices are more economic. However, marginal coal prices are higher now, as well.

So we're seeing increases in fuel prices across the board. So it's important to take all that into consideration, to your point, Commissioner, but I don't think it really changes the recommendations in this IRP.

COMMISSONER McDONALD: Which is the cheaper to operate, as we speak?

WITNESS WEATHERS: It -- it depends on the plant. So some of the -- some of the plants that get some -- some powder river basin coal are cheaper right now. But most of our plants -- or all of our plants that don't have that coal are more expensive than natural gas combined cycles.

COMMISSONER McDONALD: With your forecast that you made on natural gas prices over the next year or so, your affiliate gas marketer sends letters to consumers out there with a fixed rate. It's 100 percent difference from what it was this time a year ago. The fixed right price.

Does that speak to the fact that over the next year that we're going to see natural gas prices come down?

WITNESS GRUBB: So, Commissioner, I think it's important, and Mr. Weathers hit on it, the -- the short-term gas prices are high. What we're looking at here are long-term 30-year studies that we're doing.

And it's important to remember that even though coal prices are up, the coal retirements up at Wansley don't take place for another five or six years. And so we'll -- we totally expect that without a total fundamental change in natural gas, which we don't see, that once these PPAs take effect in '25 and the coal units are retired in the '20s, that that long-term trend of gas being rated more than coal is going to be there.

And then another reason that we're -- that we're recommending the retirement of the coal units is future environmental rules. And we've got the opportunity now to build the transmission before we have to do ELG compliance. And we have six PPAs that were really great market values that we got through solicitation. So it's really as much of a risk of that next rule as it is the current economic signal on the coal units, as well.

COMMISSONER McDONALD: Mr. Grubb, I hate to do this to you.

WITNESS GRUBB: It's okay.

COMMISSONER McDONALD: But being old and grumpy, you know, it was -- it was economically feasible to build Unit 5 and 6 until a forecast of natural gas said it would not be economical. And from Southern Company that project was pulled; right?

WITNESS GRUBB: Units 5 and 6 at which plant?

COMMISSONER McDONALD: Vogtle.

WITNESS GRUBB: Okay. Yeah, I'm not --

COMMISSONER McDONALD: Stewart County.

WITNESS GRUBB: Well -- so Stewart County was -- was a projection. We never started the full projection --

COMMISSONER McDONALD: But you -- you still were basing it on the forecast of natural gas. And the reason that it was pulled was because of the new forecast of natural gas that said it would not be economical to do.

WITNESS GRUBB: Correct.

COMMISSONER McDONALD: So then with -- with that history that still is in my craw and you're giving me a forecast on natural gas again, who do I rely on and where?

WITNESS GRUBB: So, Commissioner, I will let --

COMMISSONER McDONALD: I told you I was old and grumpy.

WITNESS GRUBB: That's fine. That's fine. That's why we're here to answer your questions and do whatever we need to do.

I mean, it is one of our challenges, in terms of projections and those types of things. But again -- and Mr. Weathers touched on it. He can hit it a little bit more here.

The long-term natural gas forecast a few years ago, as you mentioned that declined, was because a lot of high prices in natural gas drove the natural gas industry to go look at the hydraulic fracking and the ability to go get more gas.

So the fact that there were high prices actually resulted in more supply, more technology, and that's what resulted in the lower natural gas forecast.

What we're seeing now we do not see as fundamental changes to that environment. We still see a lot of gas resources out there. We still see the ability to -- to use that fuel. We see it as an important part over the next several years and decades to use.

And so unless there's a fundamental change to the resources of gas in the country, even though we've got short run-ups with the Ukraine conflict and the export of LNG, we expect those prices to come down.

Is it a challenge? Absolutely.

COMMISSONER McDONALD: With the exception of the fact knowing that the resources are there, but in the present New Green Deal, can we access those resources?

WITNESS WEATHERS: Commissioner, I don't know the specifics on -- I know that's not a specific piece of legislation, but I know there's discussion about that.

But we do think that -- that rules like that could impact the ability to have new gas pipelines. And so I think it's important that the resources that are being brought to PPAs have firm natural gas transportation. And that -- that is a key benefit. That's a key feature of those -- of those plants.

COMMISSONER McDONALD: But, you know, in today's world, we don't seem to operate on rules and law. We operate on executive orders and that's -- that's what gives me heartburn.

WITNESS WEATHERS: Sometimes, Commissioner -- and I do think -- to your point about fuel markets, there is a volatility. And we do expect continued volatility in both the coal and natural gas markets.

But it's also important that we don't rely on a single natural gas forecast, but we use a range of natural gas forecasts. We think that that's proven to be -- to serve our customers well over time.

But there was a fundamental shift in the natural gas markets several years ago with the introduction of hydraulic fracking. And so that really decreased the price of natural gas. And those fundamentals are still there, but we certainly have some -- both supply and demand issues in the short term that are causing gas prices to be very high.

But from what we're seeing from looking at long-term forecasts, the fundamentals are still there for prices to come back down in the future. There will still be volatility, but we can manage that through the course of business operations.

COMMISSONER McDONALD: That's -- that's why the consumers of Georgia can have some -- some comfort knowing that the partnership between a company like Georgia Power, a Commission like the Georgia Public Service Commission, and the diversification of generation that we enjoy in this state, i.e., even with our new renewable energy programs that we have out there, it gives the consumer, the business community, and manufacturing, et cetera, et cetera, great -- great confidence that that reliability in those resources are going to be there. But that still leaves room for those questions.

WITNESS WEATHERS: Yes, sir. Yes, sir.

WITNESS GRUBB: It does.

And, Commissioner, I think one other thing to add -- and we've talked about it. On the coal side, it's really: What is that next rule?

But on the gas PPAs that we're doing, as other technologies develop and we look towards that diversification of the generation fleet, we did select PPAs with the shorter terms so that we could relook our hands in the mid '30s and see if there's other technology that advanced, what else is there. So that we can actually do exactly what you mentioned and relook over the diversification of that resource.

COMMISSONER McDONALD: I hope I'm still here to look at it.

WITNESS GRUBB: I hope --

MADAM CHAIR PRIDEMORE: Oh, you will be.

WITNESS GRUBB: I hope you are, too.

MADAM CHAIR PRIDEMORE: But I think to Commissioner McDonald's point, this is exhibited in Georgia Power and staff's agreement in the stipulated agreement on line 6, which is the six gas PPAs. So it shows a dedication to continue to diversify generation fleet.

WITNESS WEATHERS: Yes, ma'am.

MADAM CHAIR PRIDEMORE: To that end, Section 18, which is the all-source RFP.

WITNESS GRUBB: Yes, ma'am.

MADAM CHAIR PRIDEMORE: So that everyone here is clear, all-source includes solar; correct?

WITNESS GRUBB: In some form, yes, ma'am. So all-source, as we've talked about is the -- is going to be defined as we work with staff.

But, yes, in the -- in the past capacity RFP, we did allow solar to be bid in with storage. And so those are the things that we will determine, but, yes.

MADAM CHAIR PRIDEMORE: Okay.

WITNESS GRUBB: How we accommodate that, we will work with staff on that.

MADAM CHAIR PRIDEMORE: I just saved you from answering that question six more times today.

WITNESS GRUBB: Thank you, ma'am.

MADAM CHAIR PRIDEMORE: Okay. And then, lastly, as we go through on the supply side plan, Sections 2, 3 and 4. So everyone is clear, this would retire Plant Wansley, August 31st of 2022, Units 1 and 2 of the -- Coal Units 1 and 2 only with the starter CT; correct?

WITNESS GRUBB: That's correct.

MADAM CHAIR PRIDEMORE: Okay. Plant Scherer unit 3, that would retire December 31st of 2028 --

WITNESS GRUBB: Yes, ma'am.

MADAM CHAIR PRIDEMORE: -- correct?

WITNESS GRUBB: Yes, ma'am.

MADAM CHAIR PRIDEMORE: Okay. And then on line 4, you're leaving Bowen Units 1 and 2 up as a policy call to this Commission; correct?

WITNESS GRUBB: Yes, ma'am.

MADAM CHAIR PRIDEMORE: Okay. All right. Any other questions from Commissioners?

COMMISSONER SHAW: I've got one. I'm going to -- I think it is page 3 where you referenced your hydro fleet.

WITNESS GRUBB: Yes, sir.

COMMISSONER SHAW: Let -- let me get back to that point.

WITNESS GRUBB: In the stipulation,

Commissioner, or --
COMMISSONER SHAW: In this --
WITNESS GRUBB: -- testimony?
COMMISSONER SHAW: Rebuttal testimony.
WITNESS GRUBB: In the testimony, okay.
COMMISSONER SHAW: Line 14. Near the bottom of the section.
WITNESS GRUBB: Yes.
COMMISSIONER SHAW: You basically are sticking to your prior decision with regards to the Tugalo Dam, but you mention in here that Plant Tugalo's continued operation -- if that dam were removed, it would have an adverse impact on the operations at the neighboring plants.
Can you elaborate on that?
WITNESS GRUBB: Yes, Commissioner. Thanks for that question.
So the six facilities that are in the North Georgia hydro group -- so it's Burton, Nacoochee, Terrora, Tallulah, Tugalo and Yonah -- are all licensed at FERC as one project. And that is because they are operated as a continuous system of those six plants.
COMMISSONER McDONALD: Is Seed a part of that?
WITNESS GRUBB: I'm sorry? The lake, yeah. I

was -- I was referring to the names of the powerhouses. But yes, sir, it is.

COMMISSONER McDONALD: Okay.

WITNESS GRUBB: So all those lakes up there are -- are licensed from FERC as one project because they do impact each other.

And so if -- if you were to look at Tugalo, the fact that it's a dam above Yonah actually impacts the water flow that goes into Yonah that allows it to operate.

And then specifically Tallulah Falls dam, the tailrace and the draft tube that come out of the bottom of the generation at Tallulah go into Tugalo Lake. And so that -- that generator is designed to operate between the lake upstream and the lake downstream. It's specifically designed for that.

So if you remove Tugalo Dam and you remove that lake, you have to redesign Tallulah Falls because it cannot operate. So they all impact each other and that's why FERC licensed them all as one system.

COMMISSONER SHAW: Well, in your opinion, do you think that the Public Service Commission has staff or staff persons or one person that has the expertise to advise us on -- on what the best move forward is with regards to all those dams that are licensed with FERC?

WITNESS GRUBB: So, Commissioner, you have a great staff. So I don't want to chime in too much there, but it is a complicated issue. And that is why FERC has jurisdiction and looks at all of those different types of things.

And so the license amendments or the licenses that are bestowed by FERC look at all those different aspects. They are in charge of the entire project, whether it's recreational areas, water flows through the dam, the generation aspects of it. All of it is licensed as one project.

And so FERC really is the body where that license amendment and where those actions take place because they do have people to look at that. And then there's also multiple state agencies and federal agencies that are involved in that process, as well.

COMMISSIONER SHAW: So have there --

WITNESS GRUBB: It's a very robust process at FERC.

Sorry. I didn't mean to --

COMMISSONER SHAW: So has there been conversations with FERC, to your knowledge, with regards to the proposal to possibly remove the

Tugalo Dam and turn that lake into a river?

WITNESS GRUBB: So I don't know about the specific discussions around the removal of the dam. So what's happened -- that North Georgia project, which includes Tugalo, was granted a 40-year license in the late '90s. It operates through 2036.

And so the conditions of that license are that the hydro facilities, the generation themselves, have to be in an operable condition, which is why we brought forward investment plans on hydro and then the 2019 IRP, including Tugalo.

And so they have to be able to operate. And so, therefore, they -- we are filing our license amendment there because we are reinvesting in those generation to maintain those facilities through the remainder of the license.

So FERC will look at all those different things. I don't know specifically on the dam removal. I assume that would have been looked at in the '90s. It will be looked again by FERC, but I don't -- I personally don't know of a dam the size of Tugalo that FERC has ever ordered to be removed.

COMMISSONER SHAW: Well, remind me, because I don't have it in front of me. But in the '19 IRP, how much did we allocate as part of that hydro modernization program to the Tugalo Dam and how much of that has been spent to date?

WITNESS GRUBB: So there wasn't an exact -- we filed a budget with y'all. And we update that now through our reports that we file with staff.

I think the latest update at Tugalo is $115 million and we've spent $26 million on scoping and engineering and getting ready to do the work. Part of that process has always been and always known to be filing that license amendment at FERC.

And so that's what we're waiting on right now at Tugalo is for FERC to render a decision on the license. And then we would continue to do the work to invest in those units and get them back up and running.

COMMISSONER SHAW: Thank you, sir.

WITNESS GRUBB: Thank you.

COMMISSIONER JOHNSON: Madam Chair, yes.

MADAM CHAIR PRIDEMORE: Go ahead.

COMMISSIONER JOHNSON: How much did you say was already spent?

WITNESS GRUBB: I believe $26 million.

COMMISSIONER JOHNSON: 26 million.

WITNESS GRUBB: So that's -- that's scoping, engineering, doing the RFPs and looking to procure the equipment. And then we have to go to FERC before we can actually physically do work on the units. So that's what we're awaiting.

COMMISSIONER JOHNSON: Thank you.

MADAM CHAIR PRIDEMORE: All right. Any other questions from Commissioners?

(No response.)

MADAM CHAIR PRIDEMORE: Go ahead, Mr. Walsh.

MR. WALSH: I would share as the Public Interest Advocacy Staff has entered into a settlement with the company and the panel's testimony this morning was that stipulation represents a fair and balanced result in this case. Staff does not have any questions. Thank you.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Walsh.

All right. Start with the list. Americans for Affordable Clean Energy.

MR. GALLOWAY: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: Commercial Group.

MR. JENKINS: Madam Chair, I'd repeat what Mr. Walsh said. Since the Commercial Group signed the settlement, we have no questions for the panel. Thank you.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Jenkins.

Concerned Ratepayers for Georgia.

MR. PRENOVITZ: I have some questions, ma'am.

MADAM CHAIR PRIDEMORE: Well, it's good to see you, Mr. Prenovitz.

MR. PRENOVITZ: Thank you. You, too.

MADAM CHAIR PRIDEMORE: You can go ahead.

MR. PRENOVITZ: Good morning, panel.

MR. HEWITSON: Madam Chair --

MADAM CHAIR PRIDEMORE: Yes.

MR. HEWITSON: Mr. Prenovitz sponsored testimony in this IRP. I believe the procedural and scheduling order in Section 4, No. 3, I think, H, states that if you sponsor testimony you do not get to conduct cross-examination.

MR. PRENOVITZ: May I respond?

I wrote a cover piece with the exhibits that I included. And if Mr. Hewitson is partially correct. On the first round when Georgia Power's panel testified, I did not have any questions and I offered testimony. But since this is the rebuttal phase and I do not have the opportunity to provide additional testimony, I should be able to question the witnesses.

And, number two, since the stipulation was introduced after we testified, 14 pages of that, I should also have the opportunity to question the panel on that stipulation.

MADAM CHAIR PRIDEMORE: Mr. Prenovitz, I have checked with general counsel and they are -- Mr. Hewitson is correct.

So, I'm sorry, but there will be no questions today.

MR. PRENOVITZ: Okay. I accept your ruling. I just thought I'd ask. I think I've made a good case, but I accept the decision.

MADAM CHAIR PRIDEMORE: Never hurts to ask, Mr. Prenovitz.

MR. PRENOVITZ: Thank you, ma'am.

MADAM CHAIR PRIDEMORE: Hope you're well.

Georgia Association of Manufacturers.

MR. JONES: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: Georgia Coalition for Local Governments.

MS. BROWN: No questions.

MADAM CHAIR PRIDEMORE: Georgia Interfaith Power & Light and Partnership for Southern Equity.

Hi, Ms. Kysor.

MS. KYSOR: Good morning. Not too many questions.

CROSS-EXAMINATION

BY MS. KYSOR:

Q Good morning, panelists.

A (Witness Grubb) Good morning.

Q Mr. Mitchell, I don't have any questions based on your testimony. But for the rest of the folks, I'll just let y'all answer.

Mr. Mallard, I think the first couple are pointed in your direction.

A (Witness Mallard) Great.

Q In the April hearing, do you recall some discussion of Florida legislation to roll back annual retail rate net metering?

A (Witness Mallard) Generally, yes.

Q And are you aware that since that hearing Governor DeSantis had vetoed that legislation?

A (Witness Mallard) I am aware.

Q Meaning the annual net metering is still available there in Florida?

A (Witness Mallard) It's my understanding that it's still available now. It's also my understanding that the issue is not settled in Florida. That particular piece of legislation was vetoed by Governor DeSantis, but my understanding is that the issue will remain a topic of discussion at the legislature there.

Q And monthly net metering, the policy chosen by this Commission, would you agree that's a more conservative policy than annual retail rate net metering?

A (Witness Mallard) You know, maybe technically. But, in general, it's the same policy. It's paying a retail credit for excess solar energy that's pushed back for the grid that really is better value than an avoided cost price.

The only difference would be in monthly netting, Commissioners. There's no rollover from month to month. It's settled up each month.

But it's my experience that that represents a very small portion of the total output of the customer generator. So the difference is there, but relatively small.

Q So net excess at the end of the month under monthly net metering would be paid out at the avoided cost rate; correct?

A (Witness Mallard) That's correct.

Q So it's purchased from Georgia Power at the avoided cost rate?

A (Witness Mallard) Georgia Power purchases it on behalf of customers, yes.

Q And so -- as you said, there's no roll over to future months. So we don't have to worry about, you know, someone with rooftop solar over-generating in the summer and rolling generation over to the winter; right?

A (Witness Mallard) You don't have to worry about that, but the monthly netting that we do have still does encourage customer generators to oversize. They're going to get paid at a retail rate up to the amount of their total consumption at their -- at their premise each month.

So, no, it doesn't roll over month to month, but we still do pay that retail rate for any energy pushback on the grid each month.

Q On page 55 of your rebuttal testimony, lines 1 and 2, you note the company is conducting a comprehensive evaluation of the program and that the program impacts would be shared with the Commission and the staff.

Do you see where I'm looking? Page 55 at the top.

A (Witness Grubb) Which line?

MADAM CHAIR PRIDEMORE: Do you want to give a line?

MS. KYSOR: Yes. Lines 1 and 2.

WITNESS MALLARD: Yes, I'm there.

BY MS. KYSOR:

Q I was curious, when you say shared with the Commission and staff, will it be filed publicly?

A (Witness Mallard) I don't know that the decision has been made there yet. We are continuously gathering that information, evaluating it, and we'll have ongoing discussions with staff and Commissioners as we get more customers with the year's worth of data and we get that complete picture. But I -- I don't know that a decision has been made to share that information publicly or not.

Q Would you agree it's a topic of significant public interest?

A (Witness Mallard) Yes. I would say it's a topic of significant interest for Georgia Power and all of Georgia Power's customers.

Q And then page 56, lines 2 and 3, of your rebuttal testimony.

A (Witness Mallard) Yes.

Q You note that monthly netting generates a loss of revenue greater than the cost saved. Now, you haven't conducted a cost of service study and filed it in this docket; right?

A (Witness Mallard) That is correct. We do not have a statistically valid sample of information there. But I can tell you we're -- possess anecdotal evidence that's a few years old, but where we've studied some individual customers.

Those customers showed that when we're able to measure their demand, both before and after, and the loss of kilowatt hour sales based on that small sample, we did show that more revenue was lost than cost saved, which does create that cost shift. Those costs then have to be recovered by other -- by other customers.

Q Now, you did file a data response in this docket though that showed that so far your monthly netting customers are still using on average about the same, if not a little more, than the average residential customer; right?

A (Witness Mallard) So -- yeah. But that's not really the conclusion that's important there. Generally speaking, larger customers are ones that are installing solar.

So even after they've installed solar, they might still be above the average usage. They're definitely using a lot less than they were because they're most likely -- as a class of customer there, they use more than the average customer.

Q You'd agree customers can buy less from the company if they choose to; right?

A (Witness Mallard) Absolutely.

Q Switching gears to the community solar program, specifically the low-income community solar pilot. Do you recall testifying that the low-income community solar pilot would create a net positive on customer bills,

participant bills?

A (Witness Mallard) Yes.

Q And do you think there would be a monthly net positive for customers?

A (Witness Mallard) I think over the course of a year that the customers that would participate -- those low-income customers would see a net benefit. It is possible that on a particular month with potentially high customer usage, low solar output from the solar farms, they could potentially math -- mathematically you could have a month where the customer -- it actually costs them more. But over the course of a year, we're confident that the customers who participate will receive the benefit.

Q Has the company conducted a month-by-month analysis estimate?

A (Witness Mallard) Yes. There has been analysis not on a full data set, but on some example customers. A monthly analysis has been completed.

Q And the monthly analysis has not been filed in this docket; right?

Just the annual average?

A (Witness Mallard) That's correct.

MS. KYSOR: Could I, Madam Chairwoman, make a hearing request for the analysis on monthly impacts

to customer participants' bills in the low-income community solar pilot?

MADAM CHAIR PRIDEMORE: Let me check with counsel on that because we are -- today is rebuttal. So I don't know if we're -- we might be out of time for your request, Ms. Kysor. But I'll get back to you on break.

MS. KYSOR: Great. Thank you.

BY MS. KYSOR:

Q Looking at the stipulation, paragraph 7. That's where you discuss the community solar pilot.

Will the company consider including a hold harmless or bill neutrality provision to ensure that energy-burdened customers are not paying more in any given month?

A (Witness Mallard) I'm sorry, Ms. Kysor. Can you point me to the section again?

Q Yes. It's the stipulation, paragraph 7, I believe.

A (Witness Grubb) Item 7? I think that's the PPA additional sum.

Q Oh, no.

A (Witness Grubb) Sorry. We'll chase it down.

A (Witness Mallard) I think we're looking for 27.

Q You're right. I missed the two on my outline.

A (Witness Weathers) Or page 7.
A (Witness Grubb) Yeah. There you go. It was page 7.
Q Thank you. Page 7, item 27.
And I actually don't think you need to be looking at it. So I just stepped in it for no reason.
But will the company consider a hold -- including a hold harmless or bill neutrality provision for its low-income community's solar pilot to protect customers from upward pressure on bills?
A (Witness Mallard) You know, not at this time. We're here -- the stipulation calls for approval of the community solar pilot as it was -- as it was proposed. I would like to see the program rolled out, see what the experience is with customers.
We're really optimistic that we've got a really good program design and it's going to benefit customers. And so at this time it would be our plan to implement the program as it was proposed and approved here in the stipulation.
Q In your opinion, do you think that income-qualified customers would be more interested in participating in the community solar program if they could save money on their electric bills or learn more about solar programs?

A (Witness Mallard) Both. I think bill savings is very important. I also think there is a desire out there to understand more about solar energy, the benefits that it brings both to individuals and communities.

And so that's really the great part of this design of this program. It allows customers to get both a financial benefit, but to also learn more and understand more about the benefits of solar.

Q And paragraph 27, same paragraph, you note that the company will have quarterly participation reports that you'll file. Do you expect those filings to occur in the IRP docket?

A (Witness Mallard) I do not know.

Q Do you expect they'll be filed publicly?

A (Witness Mallard) So generally I'm thinking back to the reports that we file now. They are filed -- I just don't know if they're filed in the IRP docket or if they had a separate docket in which they were approved.

But, generally speaking, we file a trade secret and a public disclosure version of our quarterly report. So I would expect that -- I would expect that to continue.

Q And I'm hesitant to say paragraph 14 of the stipulation, but it looks like I'm correct in my outline

this time. And I think Mr. Grubb or Mr. Weathers, this might -- or Mr. Robinson, I might be shifting to y'all now.

So this paragraph addresses the reserve margin. Do you see where I am?

A (Witness Grubb) Yes.

Q Paragraph 14. I just want to make sure I understand the paragraph correctly.

Does this mean that under the stipulation there would not be an approved winter target reserve margin set by the Commission?

A (Witness Weathers) I think -- yes. It means there is not explicit approval of a target reserve margin as a number. But the company obtained approval from the Commission in the 2019 IRP to use a 26 percent winter target reserve margin for planning purposes, which we have done the past three years and we will continue that with this stipulation.

Q So basically it's -- the agreement would continue the status quo from 2019?

A (Witness Weathers) Yes. In terms of using it for planning purposes.

Q And then about midway through that same paragraph, paragraph 14, it goes on to say that, you know, you'll continue using it for planning purposes until there is a winter TRM agreed to between PIA staff and the company. Do you see that?

A (Witness Weathers) Yes.

Q Do you expect that agreement to happen in the next IRP or following this IRP?

A (Witness Weathers) Well --

A (Witness Grubb) So we always -- we always do file an update in the next IRP. So regardless of -- if we're able to work with staff and, you know, talk about the issues and resolve it between them, we could.

But, really, this is noting you don't really have to have driving resource decisions for the next few years. So most likely we would be bringing the reserve margin study back in the '25 IRP and discussing it there.

So, again, the main driver of that again is when do I need to add resources. And we've got enough through that next '25 IRP. We don't have to address it between now and then if we don't have to, so...

Q Great. Just sometimes it can be tough to discern what are follow-up items from this IRP and what's getting pushed to the next one.

A (Witness Grubb) Right.

Q Do y'all recall -- Table 4 in the main document in the IRP is I think the table where you list the year of capacity need or where -- what years you're under and over.

A (Witness Grubb) Yes.

Q Are you generally recalling that?

A (Witness Grubb) Generally, but let me get to it.

Q It's on page 10-68.

A (Witness Grubb) Almost there.

A (Witness Weathers) That helps.

A (Witness Grubb) Table 4, yes. It's the capacity needs for winter and summer, yes. I've got that.

Q And was the -- was Table 4 developed assuming a winter target reserve margin of 26 percent?

A (Witness Grubb) It was. And so when you see those numbers, that's the math underneath, that's correct.

Q And so without the Commission approving an express winter target reserve margin, does that change the year of need at all for you?

A (Witness Grubb) It does not. And so if you -- if you looked at what staff recommended, then you would have a higher positive number in the years in black and you would have a slightly lower number in the red. But it's not enough of a difference to move that capacity need year up.

Q And now I'm going to the double check my paragraph number again. Paragraph 4 of the stipulation with the coal unit retirements --

A (Witness Grubb) Yes.

Q -- specifically related to Bowen.

A (Witness Grubb) Yes.

Q So Commission staff and the company reached a proposed settlement here. But it's the company's position that continued operation of Bowen Units 1 and 2 is uneconomical and not in the best interest of customers; right?

A (Witness Grubb) That's -- that's what our study showed. But, again, we agree to leave that Commission -- as the Commission's decision.

Q And were y'all present during staff's testimony in the last round of hearings, specifically the Newsome, Hayet, Wellborn?

A (Witness Grubb) Watched them. We weren't here in the room. But, yes, we did watch them.

Q And do you recall when Staff Witness Newsome acknowledged that none of the gas PPAs were needed initially in the first few years?

A (Witness Grubb) I don't remember specifically. And I don't remember which years he was referencing, but they -- they do take -- they do take effect before the coal units are retired.

Q And do you recall Witness Newsome was specifically talking about Bowen Units 1 and 2 being one of the main drivers for the need on all six of the gas PPAs and acknowledging that if not all the units were retired then you might need to revisit the decision of whether to approve all the gas PPAs?

A (Witness Grubb) So we still see the value in all six PPAs, as listed in the stipulation. Bowen is available through '27. So that chart that we were just looking at still assumes those units there.

So really by extending Bowen 1 and 2, you're really moving that '29 need year out to around 2030. But those R- -- those PPAs are very valuable. And really what they do is, yes, you have them during the '25 through '29 while you also have the coal units, but what they really do is they prevent you from having to buy anything else in the '30s, which we expect that market to be a lot more extensive than what we are holding in hand right now.

Q Can -- but regardless of what happens with Bowen Units 1 and 2 or -- excuse me -- with the gas PPAs, the company's preferred approach with Bowen 1 and 2 would be that the units are retired as proposed; right?

A (Witness Grubb) That is what our study showed.

That's what we recommended, but we're leaving up to the Commission.

Q And you noted the need in the late '20s and early '30s. If the Commission declined to approve all six of the gas PPAs and instead only approved five or something like that, would you agree that the all-source capacity RFP could be increased in size to accommodate for any expanded need?

A (Witness Grubb) It would have to be. But, again, I think what we see from this capacity RFP, Commissioners, is the bids and the prices that we've got -- that we've got in hand right now are 25 to 30 percent cheaper than what we have on those contracts now. It's a really, really good value.

When we look out to '29, '30, '31, Ms. Kysor is correct, any PPA that's not approved here, that many megawatts would have to be procured in '29 or '30. But we see a really tight market out there right now as we look.

So we don't -- A, we don't believe that these resources may be available to bid into an RFP. If they do, we expect the prices to be higher. And then you could find yourself where there is enough need where you actually have new construction that has to be bid in.

So we see that next RFP having more expensive pricing than what we have in hand right now. We don't know that for sure, but all signs indicate that. You don't have anybody building new gas resource and you have people retiring coal units so the market will be tighter.

Q But, like you said, you don't know, and Commissioner McDonald pointed out, a lot of volatility in the fuel market?

A (Witness Grubb) Correct. But we -- well, again, what we're holding is capacity prices that are 25 or 30 percent lower than what we have on the same units now. They're really good deals.

And, as Mr. Weathers pointed out earlier, you've got that firm transportation for gas that is highly valuable because the ability to build new gas lines for new units is extremely expensive.

Q And just a couple of clarifying questions about the stipulation. Paragraph 26, where you discuss quarterly filings related to the R3 REC sales program, will those quarterly filings be in the IRP docket?

A (Witness Mallard) Subject to check. I would just assume that they're going to follow the same sort of filing structure that we've done for our quarterly reports for prior programs.

Q And paragraph 29 of the stipulation discusses some changes to the RCB framework.

A (Witness Grubb) Right.

Q Will other parties -- I think there's some discussion of staff and the company, but will other parties have any opportunity to participate in those ongoing discussions on the RCB framework?

A (Witness Grubb) So the stipulation is for us and staff to work on that, but we're always, you know, open and willing to talk with other parties, get your thoughts on the RCB. We have the ability to have testimony filed here in the IRP, but we're always open to having discussions. But in terms of those specific meetings, it would just be us and staff.

Q So do you believe it would be a transparent process?

A (Witness Grubb) Look, from the standpoint of the results are applied in RFPs that are able to have bidders and other parties involved in the RFP. So as a result I believe it would be.

Q With respect to the changes in the methodology, would you consider that a transparent process?

A (Witness Weathers) Well, I think the company's commitment to work with the Commission staff on some very technical issues. And I think that when we -- to the extent there are any changes in the RCB framework that we file in the next IRP proceeding, we need to be very transparent about what those changes are and describe them in detail.

Q And paragraph 34 of the stipulation touches on the DER local reliability pilot. Do you see that?

A (Witness Robinson) I do.

Q Have the sites been selected yet for this pilot?

A (Witness Robinson) Not the specific sites, but the meters have been selected based on the criteria that was set forth in our testimony.

Q Do you know what types of facilities might be chosen, like whether it's an industrial facility or a church or a community center, anything of that nature?

A (Witness Robinson) We'll be open to looking at where the best siting is for the issue that we're trying to resolve. It could be any of those.

MS. KYSOR: Thank you.

Thank you, Commissioners.

WITNESS GRUBB: Thank you.

MADAM CHAIR PRIDEMORE: Georgia Large Scale Solar Association and Advanced Power Alliance.

MR. CARVER: Good morning, panel.

WITNESS MALLARD: Good morning.

WITNESS GRUBB: Good morning.

WITNESS WEATHERS: Good morning.

MR. CARVER: I just have a short line of questions for y'all.

CROSS-EXAMINATION

BY MR. CARVER:

Q So isn't it true that most all of the least costly utility-scale projects which have been below avoided costs have been in South Georgia -- located in South Georgia?

A (Witness Mallard) So define South Georgia would you, please.

Q Sure.

A (Witness Mallard) Specific counties or north or south of I-20; is that where we're going?

Q Sure. Why don't we just call it the fall line or, as we say from South Georgia, the gnat line.

A (Witness Grubb) I'm familiar with the gnat line.

COMMISSONER SHAW: I think it's around Unadilla.

MR. CARVER: Thank you, Commissioner.

MADAM CHAIR PRIDEMORE: South of Yoder's in South Georgia.

WITNESS MALLARD: It's definitely true there's been a preponderance of utility-scale solar that's sited in South Georgia. I will point out we have had utility-scale solar in our most recent RFP locate north of I-20. And then to go all the way back to LSS, where the original large-scale solar project was north of I-20 just barely there in Walton County.

So predominantly in South Georgia. Also some in Southeastern Georgia, kind of Central Georgia, Macon, and over towards Augusta is another -- another area with a lot of solar development.

BY MR. CARVER:

Q Isn't it also true that most of the interconnection requests for utility-scale projects have been for projects in South Georgia in the interconnection queue as it stands now?

A (Witness Robinson) Yes, that's correct. And we stated that in our testimony. Since we filed our 2019 IRP, if you look at R queue as well as the ITS participants queue for generation interconnection, it's over 17,000 megawatts of solar and battery requests that have been made in the queue and particularly in the South Georgia area.

Q In fact, Witness Robinson stated: We're going to need significant transmission built that's not in this plan. We're working on that with ITS participants today to move those megawatts from South Georgia to North

Georgia to address those constraints that we are starting to see today; isn't that correct?

A (Witness Robinson) I'm sorry. My microphone is dead. But, yes, that is correct, sir.

Q Okay. Turning to this stipulation -- the stipulation, the stipulated agreement, isn't it true that there is not a provision currently for increased transmission capacity to get solar from South Georgia to North Georgia?

A (Witness Robinson) The increase in solar in South Georgia was not anticipated in this -- in this IRP. And so what this IRP addresses is specific retirement assumptions. And the projects associated with those are laid out in the ten-year plan.

The strategic solutions that we mentioned before are solutions that we're working on for the eventual retirement of Bowen 3 and 4, along with the assumptions that are in the ten-year plan here, as well as looking at that bogey of 6,000 megawatts of additional solar by 2035. And, also, looking at our ITS participants, the EMCs, municipalities in the state, the activity that they have ongoing, the increased customer requests that we're getting -- not only us, but EMCs, as well -- for 24/7 renewables. That's -- that's increased significantly over the last six to eight months.

So the plan that we're working on is putting that out there long term in the next 13, 15 years and the transmission system that we've got to build to accommodate all of those things.

Q So in the intervenor and staff case, we had a -- a transmission expert. I don't know if you happened to see this, but I'll just ask y'all the question, too.

If we were to delay the closure of Plant Bowen's 1 and 2, as has been put in the stipulated agreement as a policy decision for the Commissioners, would that mean that transmission projects or upgrades in North Georgia that would have needed to accommodate Plant Bowen Units 1 and 2 coming off-line -- would that then make it possible that some of the transmission upgrades could be done in South Georgia instead?

A (Witness Robinson) We believe those transmission updates -- upgrades need to go forward as planned. Because as Mr. McDonald had mentioned before, as Mr. Grubb had mentioned, we're anticipating that next regulation coming out of Washington. And that could change the decision on Bowen 1 and 2, even if the Commission were to make a decision -- a policy decision on those units and defer those. We feel, as well as the ITS participants feel, that those projects need to go forward as planned with the dates associated with them.

Q It's also possible that this Commission could order an independent evaluation of the best least costly options for transmission upgrades across the state; isn't that true?

A (Witness Robinson) They could. But we feel that we are the best ones -- us and the ITS participants are the ones that are best to plan the system. We understand the system better than anyone.

And we see the needs holistically, not just for renewables, but for our customers for reliability ensuring that we are jointly planning with our neighboring utilities, as well. All of those things have to be considered when we plan the system, not just increased renewable capacity.

Q Understood. But isn't --

MADAM CHAIR PRIDEMORE: Mr. Carr -- Mr. Carver, isn't it -- I mean, this is the Georgia Power system. The five of us and the staff that supports us, we are regulators assigned by the state of Georgia to regulate their system though. We don't own the system, operate the system.

Is that true?

MR. CARVER: Yes, that's true, Madam Chair.

MADAM CHAIR PRIDEMORE: Okay.

BY MR. CARVER:

Q But it is true that they could order such an independent evaluation; is that correct?

A (Witness Robinson) I don't know legally if they could. I don't understand the statute. But if they -- if it was in their purview to do so, they could.

MR. CARVER: Thank you very much. No further questions.

MADAM CHAIR PRIDEMORE: Georgia Solar Energy Industry Association, Solar Energy Association and Vote Solar.

Hello, Mr. Thomasson.

MR. THOMASSON: Good morning, Madam Chair.

Gentlemen, how are you?

WITNESS GRUBB: Good morning.

Not too many questions for y'all.

CROSS-EXAMINATION

BY MR. THOMASSON:

Q I want to start on page 47 of your filed testimony, line 25. In your testimony you state that you -- you argue --

A (Witness Grubb) I'm sorry. Direct or rebuttal?

Q I'm sorry. The rebuttal.

A (Witness Grubb) I'm sorry. We were shuffling around.

Okay.

Q And I don't think it's a nitpick point that you're making here. But you argue that the recommendations for higher solar procurement amounts in this proceeding are not supported by analysis; correct?

A (Witness Mallard) Yes. Give me the line number one more time, Mr. Thomasson.

Q I'm sorry. That's line 25 on page 47.

A (Witness Mallard) Yes.

Q So it's that first line of your answer.

A (Witness Mallard) Got it. Thank you. Yes.

Q Okay. But that's in -- that's sort of directly talking about GLSSA's testimony; correct?

A (Witness Grubb) Correct. Yes. So this is -- this is the recommendation from an intervenor about 4,000 megawatts, not having an analysis. Not the company's analysis, that's correct.

Q But to that point, does the company's analysis in the original IRP document include solar procurement amounts as part of the generic expansion plan analysis that -- that differ between the middle gas scenario and the high gas scenario that might be larger than that?

A (Witness Grubb) Yeah. It --

A (Witness Weathers) It does. It contains -- depending on the scenario. Like you said, depending on the gas price, the carbon price, there are different amounts. And there are some that are less than what the company has proposed, some that are more. The company took an average across the scenarios for its recommendation.

Q But for the high gas scenario, the expansion has much higher numbers for solar procurement; would that be correct?

A (Witness Grubb) Through 2035.

A (Witness Weathers) It does. But it's also important to realize that this analysis the company performed was for the years 2026 through 2035. And so we're talking about four years from now.

And as we talked about earlier, natural gas prices are higher now, but over the long term, or the latest projections that we have, indicate that the current low, moderate and high gas prices are still reasonable gas prices to use.

A (Witness Grubb) And so what the company proposed was the 2,300 to do immediately for approval in this IRP with the guidance of the 6,000. And we noted to your questions that that number can change over time as we see the markets move, but the 2,300 is really what we need to do now.

And a lot of that is driven by the need to invest in transmission and how much you can physically

deploy. So it's the 2,300 gets you on that path to 6,000 and we'll work towards that. And then after that next IRP, we'll update that as we see market conditions shift.

Q Commissioner McDonald asked you some -- some grumpy questions about your natural gas prices or your natural gas projections.

A (Witness Grubb) Right.

Q If this Commission were to make a policy decision that the company is understating or underestimating natural gas prices over the mid and long term, would you say there is analysis in your IRP to -- that would justify a higher solar procurement number in the short term?

A (Witness Grubb) So I think that -- to your point, I mean, yes, if you go and put -- pick a certain scenario that makes -- say, you know, go do more renewables. But, again, our number is not just driven by that guidance. It's also driven by physically what we can deploy between the end of the '20s with a need to build transmission and actually deploy those physical resources.

And so a part of that is based on: How do we address the transmission aspects of it? So, yeah, I mean you could say to do more. I think physically we would not probably be able to do it in that same time frame.

We'd have to need more time.

But, you know, the natural gas forecasts that we looked at were long-term type forecasts, not just short term.

A (Witness Robinson) And from a transmission constraint perspective, if we're not successful in finding some solar in North Georgia, given the projects we're going to have to do in the southern and middle part of the state, it's going to be very difficult for us to reach that 2,300 that we have in the stipulated agreement today.

So, you know, that's why we said we would work with staff to develop a process to hopefully facilitate development of solar in North Georgia. It's not just a cost thing. It is a timing so we can build that transmission and hopefully get on the glide path of 2,300 by 2025.

MADAM CHAIR PRIDEMORE: Mr. Robinson, can we -- I know we've talked about this North Georgia Reliability Study and Transmission a lot, but I think what -- what was a real eye opener for me is we're not talking about Fannin, Union, Walker counties. We're talking -- we're talking about Atlanta because we know that's where the load is.

And so we're talking about getting transmission

resources and solar closer to where the load is; is that correct?

WITNESS ROBINSON: That's correct. And in the North Georgia area there is over 16,000 megawatts of load. But that's significant. That is more than half -- significantly more than half of the state.

MADAM CHAIR PRIDEMORE: Yeah.

BY MR. THOMASSON:

Q All right. We'll move on to the RFP -- your testimony in the RFP process. Starting on page 50 at the top of the page, you point out that Georgia Power's RFP process is laid out in the Commission rules; correct?

A (Witness Grubb) Yes.

Q And that process is used for -- that same RFP process from the rules is used for new capacity resources, for utility-scale solar and for DG solar?

A (Witness Mallard) That's correct.

Q Do you know if the rules -- if the Commission's rules specifically require that that entire process apply to DG solar procurement or is it just new capacity resources?

A (Witness Mallard) So I'm -- I'm not able to offer a legal opinion. But my understanding is that the company is procuring resources to meet a need approved in an integrated resource plan that the rules will apply no

matter the size of the resource, whether it be a DG or a utility-scale RFP.

Q Okay. But would you -- would you agree that the Commission has the authority as a policy decision to modify the DG RFP process and either to depart from what's in the Commission rules or, as an alternative, to maybe add on top of those -- the Commission rules something specific for, say, one DG's or procurement specifically?

MR. HEWITSON: Madam Chair, I think Mr. Thomasson is asking the panel to make a legal conclusion.

MADAM CHAIR PRIDEMORE: Sustained.

MR. THOMASSON: I will ask it a different way.

BY MR. THOMASSON:

Q Are there changes the company could make to add more process to the DG procurement that would be in addition to Commission rules and not contrary to Commission rules?

A (Witness Mallard) So I suppose that's possible. The way I see that is -- I think about it either as a procurement -- a competitive procurement, which this Commission has authorized going all the way back to 2012 and before where those -- you know, market competition really has produced really good value for our customers.

It started in the utility scale. We moved that over to distributed generation. To me, we've got one of the leading competitive markets for distributed generation in the country.

And so going -- following those rules mimicking that utility-scale process I think has served us really well in the DG market. Now, that's not to say the Commission couldn't approve a separate program, we'll call it, something more like our customer-connected program or our old REDI customer sited program where it's not necessarily a competitive bid program. And so the rules don't apply in the same way.

So there's -- there's other ways to procure renewable energy. But the way I see it is the competitive procurement produces the most benefits for customers. It's been working well and that's what we propose to continue to do in the DG market.

Q All right. I'm going to move on to monthly netting where y'all start on the bottom of page 54 and then through page 55. Ms. Kysor asked y'all some questions already --

A (Witness Mallard) Yes.

Q -- specifically about the analysis that y'all are performing on monthly netting. And that's -- that's ongoing and the company has no plans to file anything in

this proceeding obviously based --

A (Witness Mallard) No, not in this proceeding. The analysis is not done yet. Just as an update, we are approaching getting all 5,000 customers online. We filed -- we are just north of 4,200.

There's some projects out there that are not moving that we're going to clear out here really soon and move down the waiting list. So we should be to the 5,000 very soon.

But the analysis is ongoing and we are already deeply engaged in taking a look at those cost shifts, both from the energy pushback to the grid, but also the energy that's consumed on-site from the customer generator.

Q But the company doesn't have analytical support for those concerns in the record in this proceeding?

A (Witness Mallard) The company does have support for the amount of cost shift that's caused by the energy that's pushed back from the grid. So think about that excess that goes back to the grid.

Our estimate there is the 5,000 customer pilot is causing about a million and a half dollars of cost shift from those with solar to those without. But that's only a portion of the cost shift.

The amount that's consumed on-site, which is

the majority of the generation that the solar panels produce, that's a little bit harder. It's behind-the-meter. We have to do cost of service type analyses to understand the changes in costs and revenue. That does take a little bit longer. And, no, we won't have any of that analysis available here in --

Q And so that's not on record in this proceeding?

A (Witness Mallard) That's correct.

Q Okay. And to your point about the $1.5 million, moving on to page 56 --

A (Witness Mallard) Yes.

Q -- lines 8 through 10, you describe monthly netting as a requirement to purchase those kWh that are pushed to the grid at a rate closer to 12 cents per kWh.

A (Witness Mallard) That's right. That's an estimate of the -- of "R" rate, which is the -- the predominant rate for residential customers.

Q But the credits though we're talking about for the energy that's pushed back to the grid, those aren't actually purchases that the company is making?

A (Witness Mallard) By my way of thinking, they are. It's energy that's pushed back from the grid that the company is buying on behalf of all other customers.

Now, the method that we're purchasing is by a reduction in the retail bill for the customer -- customer generators who have solar at their home or business. But by my way of thinking, it is a purchase.

That energy is going to the grid and the company is procuring that energy on behalf of all customers through that reduction in retail rates for the customers with solar.

Q Is that --

COMMISSONER McDONALD: Mr. Mallard, in short term, when you're describing what you did, are you saying the savings that the consumer has is developed by what their normal rate would be and then they're buying solar at a cheaper rate if they use than it would be if they were buying it from -- from the -- from Georgia Power?

WITNESS MALLARD: Let me give you an example, if I can, Commissioner. A customer uses 1,000 kilowatt-hours a month. They have a solar -- rooftop solar that produces 400 kilowatt-hours a month. They consume 300 of those on-site. So their new bill is 700, but there's that last 100 that gets pushed back to the grid. The extra when they are overproducing.

Under the old -- the old monthly netting it would be paid -- that 100 would be paid at avoided cost at about 3 cents. Under the -- I'm sorry.

Under instantaneous netting.

Under monthly netting, we now take that 100 and actually we add those kilowatt-hours back. So we're buying them, if you will, at a retail rate that's about 12 cents.

So that's really what we're talking about is that excess energy that's pushed back to the grid worth about 3 cents as an avoided cost. When we do monthly netting, we end up purchasing it at a retail rate of about 12 cents.

COMMISSONER McDONALD: Plug me in again where that 100 kilowatts when you're saying they are using 1,000 kilowatts. They're producing 400 kilowatts. You credit them with 300 kilowatts.

WITNESS MALLARD: That's the instantaneous part of it. Think about a bright, sunny morning where their air conditioner hasn't turned on yet, but their solar panel is really producing.

And so they're producing more than they're using at that moment. And by the laws of physics, those kilowatt-hours, those electrons, are going out to the grid.

COMMISSONER McDONALD: Okay.

WITNESS MALLARD: In the afternoon, when the air conditioner is on, they're soaking it all up using it on-site.

COMMISSONER McDONALD: Thank you.

WITNESS MALLARD: Yes, sir.

BY MR. THOMASSON:

Q Getting back to the purchase question --

A (Witness Mallard) Yes.

Q I mean, the company is not actually making payments for this. It's not technically a purchase.

I understand the sort of conceptual point you're making about the cost that the company is incurring, but it's not a purchase.

A (Witness Mallard) You're right. It's a -- it's realized through lower -- lower cost recovery from the customer generator through the retail account.

Q Okay. So that would be when the company comes for cost recovery?

It would be based on that and they --

A (Witness Mallard) That's right.

Q -- won't actually characterize them on -- in a rate case as purchases.

You're not sending them 1099s for the netted amounts within a month?

A (Witness Mallard) No. Under the scheme -- under this scheme, we would not. I think as we -- we looked at some different options of how to implement monthly netting.

There was one that we considered where we would sort of keep those kilowatt-hours separate and then purchase them at an average retail rate.

If you would apply methodology like that, I think it would look like a purchase, but that is -- that's not what we're doing now. What we're doing now is just removing those kilowatt-hours from their bill so we're billing them less.

Q Have you -- are you aware if that's a standard practice in other states for the utilities to characterize it that way as a purchase and pull the -- that last type of mechanism you described?

Are you aware of other utilities that do it that way?

A (Witness Mallard) So I can't say that I can call any, but I certainly am really familiar with net metering, behind-the-meter solar policies. I've studied, gosh, half the states in the union in the last 12 months or so.

So, yeah, I think -- I think one way to characterize it is that energy that goes back to the grid, in effect, it is purchased on behalf of all other customers because the energy is then used. It flows down the lines and it serves other customers.

Q So then since you've studied other states, and we talked earlier about Florida as an example of a state where the policy is conceptually close to monthly netting --

A (Witness Mallard) Uh-huh.

Q -- that we've done on a pilot basis here, but with the monthly rollover --

A (Witness Mallard) Uh-huh.

Q Are you familiar with how they characterize and monitor as those payments in Florida?

A (Witness Mallard) I can't say I'm specifically aware of that, no, sir.

MR. THOMASSON: No more questions. That's it.

WITNESS MALLARD: Thank you.

WITNESS GRUBB: Thank you.

COMMISSIONER JOHNSON: Thank you, Mr. Thomasson.

Georgia Watch. Ms. Coyle.

MS. COYLE: No questions.

COMMISSIONER JOHNSON: Interstate Gas Supply.

MR. CARVER: No questions.

COMMISSIONER JOHNSON: Thank you.

Resource Supply Management.

(No response.)

COMMISSIONER JOHNSON: He's not here.

Restore Chattooga Gorge Coalition.

Come on up, Mr. Pendergrast.

MR. PENDERGRAST: Should I proceed in the absence of everyone?

COMMISSIONER JOHNSON: Actually, we have two out so you're going to have to hold just a moment.

Is Tim on the line?

VICE-CHAIRMAN ECHOLS: I'm here, Commissioner Johnson. So we've got a quorum.

COMMISSIONER JOHNSON: Okay. Thank you, Mr. Commissioner.

You can proceed.

MR. PENDERGRAST: All right. Craig Pendergrast for Restore Chattooga Gorge Coalition with my partner, Steven Jones.

CROSS-EXAMINATION

BY MR. PENDERGRAST:

Q Mr. Grubb, you are the panel member most knowledgeable about the company's hydroelectric modernization plans; is that right?

A (Witness Grubb) That's correct.

Q And so you are the panel member most knowledgable about the company's modernization plans for Plant Tugalo; is that right?

A (Witness Grubb) That's correct.

Q Okay. And when we talk about Plant Tugalo, we're talking about a number of different components consisting of the dam, the powerhouse and the lake; is that right?

A (Witness Grubb) Plus recreational areas and other aspects of the FERC license, that's correct.

Q Okay. And the dam which creates the lake is almost 100 years old; is that right?

A (Witness Grubb) That is correct.

Q Okay. And that dam blocks navigation on the Chattooga River; is that right?

A (Witness Grubb) Well, there is a lake there now. So, yes, it does form Lake Tugalo.

Q But you can't navigate past the dam, can you?

A (Witness Grubb) I don't believe so.

Q All right. And that lake inundates about 600 acres of land; right?

A (Witness Grubb) It creates about a 597, 600-acre lake, that's correct.

Q All right. And the Plant -- the powerhouse contains four generating units; is that right?

A (Witness Grubb) That's correct.

Q And those -- and the company's Tugalo modernization plan that is -- as it refers to it would involve the replacement of all four of those generating

units; is that right?

A (Witness Grubb) That's correct. As approved in the 2019 IRP. That was one of the plants to invest in.

Q All right. And that's four turbines and four generators; right?

A (Witness Grubb) That's correct.

Q Okay. And that also would replace the electrical operating system within the powerhouse you referred to as balance --

A (Witness Grubb) Yes. Balance the plants.

Q All right.

A (Witness Grace) Update the controls, update the oil pumps, those types of things.

Q Right. And that's projected to cost $115 million; is that right?

A (Witness Grubb) That's correct.

Q All right. And that does not include any improvements to or maintenance or -- of the dam for the lake components of Plant Tugalo; is that right?

A (Witness Grubb) That's correct. I mean, this is the IRP. And so what we've brought forward for Plant Tugalo aspects here are the generation units that are the supply side plan.

The lake maintenance, the investments needed in the dam to make sure it's a solid structure, which it is, those are costs that would be recovered through rate cases in other aspects. But, yeah, that is to invest in and maintain the units so that we can meet the operating license from FERC.

Q Okay. So the cost to repair the dam, to shore up the dam, maintain the dam in the future is not included within that $115 million; is that right?

A (Witness Grubb) No. That's correct.

And, again, we've got a very robust dam safety program that we have done what we need there. We've got annual inspections. And so those costs of maintaining the dam structure itself would be handled in other areas.

Again, from an IRP standpoint, we're looking at the cost to invest in and maintain those generating units per the FERC license that are a part of the supply side plan and the IRP.

Q But, again, that does not -- that 115 million doesn't cost any future costs -- that $115 million projection doesn't include any future costs to maintain, repair, this almost 100-year-old dam; is that right?

A (Witness Grubb) So the -- I don't think there's any repair on the dam. Again, we've got a program to make sure that the structure of the dam itself is in good order.

And, yes, that 115 is for the generation aspects of it, not the entire dam. That would be captured in rate cases in other areas of the company's costs recovered.

Q Okay. That 100-year-old dam won't last forever without repairs and other things like that; right?

COMMISSONER McDONALD: Is it -- is it suffice to state Safe Dams Act that was passed many years ago in regards to the inspections when the Tallulah Falls Dam broke?

WITNESS GRUBB: I'm not familiar with that, Commissioner. I do know that we've got a very robust dam safety program that meets the requirements and the standards from FERC and also --

COMMISSONER McDONALD: Isn't there a state Safe Dam Act?

WITNESS MITCHELL: Yes, Commissioner.

COMMISSONER McDONALD: Mr. Mitchell, aren't you --

WITNESS MITCHELL: Yes, sir. And this dam is regulated by that, as well.

COMMISSONER McDONALD: I just wanted to make sure that the -- that communications were that it's not just sitting there unnoticed.

WITNESS GRUBB: That's right.

BY MR. PENDERGRAST:

Q No. And my questions were directed to the 115 million projected costs does not include future costs to be compliant with Safe Dams Act or FERC Act. That it's a 100-year-old dam and if -- when it comes time to need repairs, that's extra money that the company will have -- would have to spend; right?

A (Witness Mitchell) I would just add, Commissioner, to your point, and to the question, the company has been maintaining the dam for nearly 100 years and will continue to comply with those regulations. As Mr. Grubb testified, those are ongoing activities and the Commission has approved those expenditures.

COMMISSONER McDONALD: Put that microphone up there.

WITNESS MITCHELL: I'm sorry. Is that better?

COMMISSONER McDONALD: There you go.

WITNESS MITCHELL: The Commission has previously approved those expenditures necessary to comply with the FERC requirements and state of Georgia Safe Dams program. And the company will continue to bring those and request those expenditures as required by law and regulation to the Commission for approval in future rate cases.

WITNESS GRUBB: That's right.

BY MR. PENDERGRAST:

Q 115 million is just straight out --

COMMISSIONER JOHNSON: Mr. Pendergrast --

MR. PENDERGRAST: Yes.

COMMISSIONER JOHNSON: I think -- I think we get it.

MR. PENDERGRAST: I understand. They just haven't answered my question, but you are right. The point has been made.

BY MR. PENDERGRAST:

Q And that $115 million cost doesn't include any cost to do any sediment removal from the lake; is that right?

A (Witness Grubb) No. The way -- my understanding is the sediment is not impacting the operation of the dam. So, you're right, the 115 million is, as we've talked about, the 2019 IRP.

We need to re- -- we need to invest in these hydro facilities to maintain these resources. They're carbon free. They're the fastest reacting ones we have on the system, in terms of dispatch. There's a lot of benefits to the hydro facilities.

And in the 2019 IRP, we brought forth that hydro investment plan and Tugalo was part of that. So it is to replace the generation turbines and those types of things to meet the requirements of the FERC license, which is that those plants need to be operable.

Q In the public version of the IRP filing by the company that started the IRP process in 2019, it did not identify Plant Tugalo as one of the, quote, several hydro generating plants that it proposed to modernize; is that right?

A (Witness Grubb) The 2019 -- that's correct. In that the 2019 IRP was really teeing up modernization or investment in the entire hydro fleet. We were looking forward to getting approval for a long 10-to-12-year plan to do all of the facilities.

Working with the staff on -- staff on stipulation, agreed to five facilities. And so the stipulation addressed and specifically named those five facilities. But no -- no facilities were specifically named in 2019 because it was for the entire fleet.

Q Well, it said several of them. It didn't say all of them; is that right?

A (Witness Grubb) I would have to go back and check. But, I mean, the information we provided in the back was all -- had a listing for all of them, in terms of projected budgets. Unless trade secret, they were listed.

Q But that -- so that was not visible to the public?

A (Witness Grubb) The -- I can't recall if the names were. I know the dollars weren't.

But to insinuate that Tugalo was not publicly known, it was known in the public. Now, do we have a headline that everyone knew about it?

But it was not trade secret redacted that it was going to be one of the five plants that was approved.

Q But in the filing that was made that -- was what Georgia Power wanted to do at the outset of the 2019 IRP process, Tugalo was not identified as one of the several plants that it wanted to modernize.

A (Witness Grubb) But we were -- we were teeing up, investing, and doing the entire hydro fleet. But then -- just as in this case, the stipulation is of record in the IRP.

So once the stipulation was reached between us and staff, and it was specifically noted, the five plants that were approved to move forward with investment, Tugalo was one of them.

Q And that stipulation, the ultimate order, didn't say what was going to be done to modernize Plant Tugalo, did it?

A (Witness Grubb) In terms of --

Q In terms of what specific -- you know, what was going to be done, what did modernization mean. That's

kind of a vague term.

A (Witness Grubb) Well -- so it was investment in the plan. I think the IRP in 2019 is pretty clear that what we were needing to do was invest in the generation facilities at the hydro facilities to meet the license. So I don't think it was a mystery that we were talking about investing in the generation aspects of our hydro facilities.

Q Okay. The company didn't inform the PSC in connection with the 2019 rate case about how much silt was in the lake, did it?

MR. HEWITSON: Madam Chair, I -- I would object on relevance. I don't know what the 2019 testimony has to do with the rebuttal testimony that's here before the Commission now or the stipulation.

MADAM CHAIR PRIDEMORE: Sustained.

BY MR. PENDERGRAST:

Q Just as was the case with the -- with future dam repairs, that $115 million cost estimate does not include anything in terms of the future cost of sediment removal to provide for navigation of the lake, does it?

MR. HEWITSON: Objection. Asked and answered.

MADAM CHAIR PRIDEMORE: Sustained.

BY MR. PENDERGRAST:

Q In 2019, there was no cost-benefit analysis

provided to the Commission for the Tugalo modernization, was there?

MR. HEWITSON: Objection. Relevance.

MADAM CHAIR PRIDEMORE: Sustained.

BY MR. PENDERGRAST:

Q The modernization of the Plant Tugalo per the company's filing in this case in response to STF-JKA-4-32 says that the -- this modernization program will serve to increase the nameplate capacity of each of the four generating units from 11.25 megawatts to 16.4 megawatts; is that right?

A (Witness Grubb) I don't -- do you have that data request with you? I don't --

Q I do.

A (Witness Grubb) Okay.

MADAM CHAIR PRIDEMORE: Would you care to ask to approach?

MR. PENDERGRAST: Oh, I'm sorry. My apologies. I was going to ask to approach the panel.

MADAM CHAIR PRIDEMORE: You may.

MR. PENDERGRAST: May I?

MADAM CHAIR PRIDEMORE: Just trying to help you out here, Mr. Pendergrast.

MR. PENDERGRAST: I appreciate it.

COMMISSIONER JOHNSON: I will pass it out.

WITNESS GRUBB: Is it just the one sheet?

WITNESS MALLARD: Can we have an extra copy or one more?

BY MR. PENDERGRAST:

Q All right. Mr. Grubb, I've handed you that document.

A (Witness Grubb) Yes. Thank you.

Q Does that refresh your recollection?

Does that reflect what the current nameplate capacity of the Tugalo units are and then what the new nameplate rating -- capacity rating will be?

A (Witness Grubb) Yes. That is the case. Of course, there's a footnote that says that the actual ratings won't be known until they're directly in service. But, yes, this is the main response that we filed.

Q That's the plan; correct?

A (Witness Grubb) That is the plan, in terms of -- yes, these units and turbines are very old. And in most cases, you're not just replacing them. They're old enough that you are getting an entirely new turbine.

And they're getting more efficient. And so, yes, there is expected -- at least nameplate rating capacity. We'll have to see what that does when it's actually in operation.

Q Okay. And so that would be an increase of

5.15 megawatts per unit; right?

A (Witness Grubb) Roughly, yes, sir.

Q Yeah. And 20.6 megawatts for the entire plant; is that right?

A (Witness Grubb) Subject to check, yes.

Q Right.

A (Witness Grubb) I trust your math.

Q And that's a -- by my math, that's 45.7 percent increase?

A (Witness Grubb) Again, if those megawatt ratings manifest themselves, yes, that's correct.

Q Okay. And the company has not requested a certificate of public convenience or necessity for that upgrade, has it?

A (Witness Grubb) No. Two points there. One, from a -- the standpoint of the capacity, you'll have to see if that's really what comes to fruition. And then, also, you have to look at what you actually plan for.

The other point is we did approve -- we did receive approval to invest in the units through the investment request in the 2019 IRP.

Q There was no cost-benefit or alternatives analysis done in connection with that as required by this Commission's regulations; correct?

MR. HEWITSON: That would be a legal

conclusion.

THE WITNESS: (Witness Grubb) That's correct.

MADAM CHAIR PRIDEMORE: Sustained.

Mr. Grubb, so I've got a question for you about this. Hydro power generation is how the state originally began providing electricity; correct?

WITNESS GRUBB: That's correct. It's the original and it's the original storage and renewable resource, as well.

MADAM CHAIR PRIDEMORE: Yeah. So it is -- it is considered a beneficial piece of the renewable portfolio of the company; correct?

WITNESS GRUBB: That's correct. We usually list it out separately, but it absolutely is part of it, yes.

MADAM CHAIR PRIDEMORE: Okay. And you're aware that this Commission and the staff and Georgia Power work very hard to have a diversified portfolio of generation means; right?

WITNESS GRUBB: Yes, ma'am.

MADAM CHAIR PRIDEMORE: Yeah. How important is hydro in that?

WITNESS GRUBB: It's very important. It's --

MADAM CHAIR PRIDEMORE: Okay.

WITNESS GRUBB: When you look -- there's 1,000 megawatts of it. It's renewable. It's emissions-free. It's carbon-free.

It's the most responsive resource we have on the system. Energy storage will be there with it, but hydro is immediately brought online. It does a lot of transmission support in the area. And so it's got a lot of benefits to it.

COMMISSONER McDONALD: Are you saying that every electron that comes from the sun can only be used one time, that every therm of gas that comes from natural gas can only be used one time, but the water is used six times in this?

WITNESS GRUBB: In that's system, yes, sir. It goes through six dams, that's correct.

BY MR. PENDERGRAST:

Q And the percentage of the Georgia Power grid that is, as you testified earlier, well over its capacity, including reserve capacity even after the decommissioning of Plant Wansley units -- that the percentage of the Plant Tugalo power is 0.2 percent or something like that of this Georgia Power system; right?

A (Witness Grubb) It's a small percentage. But, again, like we've mentioned, every megawatt matters. It's got those benefits that we just spoke about. That's 45 megawatts of benefits there. You've also got the lake and all of the other aspects of that FERC license project at Tugalo.

Q Okay. In your rebuttal testimony and earlier today in response to Commissioner Shaw's questions, you said that the lake -- Lake Tugalo comes up to receive the -- directly receive the tailwater, the discharge from the Tallulah Power Plant; is that right?

A (Witness Grubb) My understanding is that the presence of the Tugalo Lake is absolutely factored into the design and the operation of Tallulah Falls, that's correct.

Q I believe you testified that the lake comes up to where the water comes right out of the Tallulah powerhouse; right?

A (Witness Grubb) Well, I was speaking generally for hydro facilities that happens. I believe it's the fact with -- the case at Tugalo -- I mean, Tallulah, but I'm not a hundred percent sure. But it does flow into the Tugalo Lake.

Q Right. But in terms of generating electricity in the Tallulah powerhouse, it -- you don't need to have lake water to be directly receiving the flow exiting the turbines; is that right?

A (Witness Grubb) Sir, are you speaking about Tallulah or Tugalo?

Q Tugalo.

A (Witness Grubb) So Tugalo. So, Commissioners, in my discussions with our hydro services engineers, Tallulah Falls is designed to operate with the plant -- the lake that it has above it and the way that the Tugalo Dam and the Tugalo Lake is below it. If you no longer have that lake, then Tallulah Falls cannot operate in the condition it is today.

Q And can you explain why you would say that? Why did they say that?

Because mechanically I'm really not following.

A (Witness Grubb) So I -- I don't know exactly when -- I'll have to go -- the point of the matter is that these guys, our hydro service engineers, run this system every day. It's what they do. It's how they make their living.

And if Tugalo Dam is gone, then Tallulah Falls cannot operate as it is today. So I was -- I believe it was -- the Tugalo Lake is where the exit of the tailrace from Tallulah Falls goes to. And if that is no longer there, it's a different pressure situation on the units. So they've got to be -- they've got to be operated differently.

And so I base that on our guys in hydro service engineers that -- that run the system every day. And without question they state that if the Tugalo Dam is gone you cannot operate Tallulah Falls in the manner it is today.

MADAM CHAIR PRIDEMORE: Mr. Grubb, that impacts hundreds of thousands of Georgians and thousands of homes. They -- I have not heard from a single solitary one of them. I don't even think that they know that this gentleman here is up here with -- intervening about this issue. This is -- this is surprising.

WITNESS GRUBB: So, Commissioner, that's true. And, again, I mentioned it this morning, the North Georgia group is licensed as all six facilities because it operates that way.

And my understanding is that the FERC process, which where this is right now, FERC will take into account all the different viewpoints. It will take into the viewpoints of the benefits of having a lake. It will take in the benefits of having a non-developed lake for fisherman to be on. So they take into account all those things.

And then, also, before we filed the license amendment, we worked with and spoke with the state -- the agencies in South Carolina, Georgia and federal agencies before we filed our amendment to reinvest in the hydro facility. And they were all in favor of it.

So all of those parties, all of those viewpoints, including the Coalition's, are being heard at FERC as we speak.

BY MR. PENDERGRAST:

Q Well, let me -- let me go back to this supposed impact on the operation of the Tallulah facility. I -- if Lake Tugalo were gone -- so the Tallulah facility is the one that pipes the water, much -- most of the water around the rim of the gorge and then it drops real far down the edge of the gorge into the powerhouse; is that right?

A (Witness Grubb) That's right.

Q And then the water in the powerhouse spins the turbines; right?

A (Witness Grubb) Correct.

Q And spinning the turbine is how the electricity is generated as the water rushes through the turbines; is that right?

A (Witness Grubb) That's correct.

Q Okay. So how does the -- where the lake Tugalo Lake is impact the generation of that electricity as the water rushes through the turbine in the Tallulah powerhouse?

A (Witness Grubb) So, Commissioners, if you think about -- and I'm no hydro engineer, but I've spent a lot of time with them. But if you think about the way a hydro facility works, you've got the lake. And Tallulah's standpoint, you've going pipes coming down. But you have a pressure differential between the upper lake -- the upper reservoir and the lower reservoir.

And so as you run that water through the turbine, it's not blowing out into free air. It is blowing into another body of water, which is actually putting pressure back on.

So that pressure differential, the entire plant is designed to operate between those two pressure differentials. If you remove the lower reservoir, you have to redo the operations of the plant that's between those two reservoirs.

So Tugalo is not just a matter of removing Tugalo. You now have to figure out what that does to Tallulah. And then, also, even though it's a minimum run-of-river plant, we do have the benefit of that lake and that dam monitoring the water that then goes in through Yonah, which is the one below it.

But the majority of the impact is to Tallulah. But all six of them, if you change any of the reservoirs, the way they store, the way they flow, any of that, it impacts all the others in that system.

COMMISSONER McDONALD: I need a little clarification here. And either -- either can respond to it.

You're referring to FERC quite a bit about the dams.

WITNESS GRUBB: Yes, sir.

COMMISSONER McDONALD: The certification of the dams is with FERC for -- until 203- --

WITNESS GRUBB: '36.

COMMISSONER McDONALD: 2036.

WITNESS GRUBB: We will file in '31 for a relicense.

COMMISSONER McDONALD: Do I understand now that this Commission's authority would be only to certify that the turbines can be adjusted or removed or replaced or whatever, but we have no real authority over the dam itself?

WITNESS GRUBB: That is my understanding.

COMMISSONER McDONALD: Is that where I am with this?

And, I mean, we talked about the millions of dollars and we haven't said it will be prorated over the next 100 years, if that's the life expectancy of the generation. But I'm trying to focus down.

Do we really -- with FERC being in the picture, and it seems to be in the picture very strongly, do we have any authority over the dam?

It's just whether we want to upgrade the generation process or not upgrade the generation process.

MR. PENDERGRAST: I can -- I can respond to that, Commissioner.

COMMISSONER McDONALD: I would like you to respond.

MR. PENDERGRAST: So there is dual authority. This Commission would have to approve the decommissioning of this facility under its general rules that if the capacity of a unit is decreased more than 15 percent or increased more than 15 percent, that if they are adding or subtracting.

And so if you're subtracting --

COMMISSONER McDONALD: The capacity being that of generating capacity or lake and -- what kind of capacity?

MR. PENDERGRAST: Generating capacity.

COMMISSONER McDONALD: All right.

MR. PENDERGRAST: Because the dam and the powerhouse are connected because you're relying on -- you're having the water that comes through the

dam and then drops down --
COMMISSONER McDONALD: You've established all that, yes.
MR. PENDERGRAST: Then that's where the -- this Commission's authority is and to spend money on things. FERC then has authority that -- because it's a navigable river. If there's going to be an impairment to navigation, which a dam necessarily does, then FERC has to issue a license for that or not issue a license for that under its rules.
So that's my read of the dual -- the dual jurisdiction.
COMMISSONER McDONALD: With all due respect, don't you think you ought to be at FERC, rather than here?
MR. PENDERGRAST: We are at FERC, too.
COMMISSONER McDONALD: Okay.
MR. PENDERGRAST: So we think -- we think it's important for both bodies to understand the situation and to be ultimately weighing in. FERC's -- FERC's present decision won't be on whether or not to decommission the facility, the dam, at this time. That will come up in 2036 when this license to have this dam expires.
And there is -- and as Georgia Power has noted

in its filings to this Commission, there is absolutely a prospect that FERC would decline to renew the license based on all of the factors that it's supposed to consider. So that is -- that is a risk.

MADAM CHAIR PRIDEMORE: That's 14 years from now.

MR. PENDERGRAST: I'm sorry?

MADAM CHAIR PRIDEMORE: That's 14 years from now.

MR. PENDERGRAST: That's correct.

MADAM CHAIR PRIDEMORE: A lot can happen in 14 years.

MR. PENDERGRAST: Correct.

MADAM CHAIR PRIDEMORE: I mean, that's Georgia Power's job when they file with this Commission is to give us both sides of it. A lot of intervenors don't have to.

You just give -- you just give us your point of view and what you'd like to see happen. But it's Georgia Power's responsibility to give us both sides of each issue.

Just because something is cited in a previous case or a previous filing does not -- does not believe that that is the company's position or that it's this Commission's position. It's that that's their responsibility by law. They have to.

MR. PENDERGRAST: I do -- I do understand that, Commissioner. And it is a, you know, legal risk. And as they noted it, it's a risk that it may not be renewed.

Well, I do want to go back, if I may, to this Tallulah Plant/Tugalo one because I do want to have --

MADAM CHAIR PRIDEMORE: How many more questions do you have, Mr. Pendergrast?

MR. PENDERGRAST: I believe I can finish up in about 15 minutes, I believe. I hope.

Let's see how this goes. But I do have a good number more.

MADAM CHAIR PRIDEMORE: Okay.

MR. PENDERGRAST: All right.

MADAM CHAIR PRIDEMORE: Would you like to approach?

MR. PENDERGRAST: Yeah. May I approach? I'm sorry.

MADAM CHAIR PRIDEMORE: Yes, you may.

(The document referred to was marked for identification as RCG-K.)

BY MR. PENDERGRAST:

Q Mr. Grubb, I've shown you RCG Exhibit K. And that is an aerial photo from the Google Maps, Google Earth as of last night.

Does that look to you to be the Tallulah powerhouse as those long penstocks come down from the edge of Tallulah Gorge?

A (Witness Grubb) Yeah. It appears to be.

Q All right. And as you look to the -- to where the lower of the two powerhouse buildings goes, you can see the tailwater coming out of the powerhouse as it -- the water has gone through those turbines; is that right?

A (Witness Grubb) That's correct.

Q And that's not -- and then you go to the south as it turns and you can see the Tallulah River that has received those tailwaters flowing over rapids before it enters the lake; is that correct?

A (Witness Grubb) That's correct.

Q So Lake Tugalo does not back up to receive directly the waters as they have run through the turbines; correct?

A (Witness Grubb) Subject to check.

But, Commissioners, what I will say again is I do not operate this hydro facility, but I have talked with our hydro service engineers who have said without a doubt that the removal of Tugalo Lake -- now, whether

it's the lake that impacts back this flow into the tailrace here on Tallulah, I'm not sure. It's some complicated things and water and everything when you start talking about pressure differentials and flows.

But, without question, they have said that if you remove Tugalo Dam, it impacts how Tallulah Falls can operate. Now, I can't sit here and go through all the hydro dynamics and everything. That's not my job. But they have said without a doubt that it impacts Tallulah Falls.

COMMISSONER McDONALD: Can you find that out in the next 14 years?

WITNESS GRUBB: Yes, sir. Probably in the next few months for you.

COMMISSONER McDONALD: Thank you.

MADAM CHAIR PRIDEMORE: Mr. Pendergrast --

MR. PENDERGRAST: Yes, ma'am.

MADAM CHAIR PRIDEMORE: -- has your client -- your Washington D.C. client, has she met with representatives from Habersham or Rabun counties in Georgia or Oconee County in South Carolina about this?

MR. PENDERGRAST: I do not know.

BY MR. PENDERGRAST:

Q In connection with this 2022 IRP, the company has not engaged in a cost-benefit or alternatives analysis with respect to the proposed -- to the Plant Tugalo modernization; is that correct?

A (Witness Grubb) That's correct.

Q Thank you.

A (Witness Grubb) Not for Tugalo because, again, the Commission has approved in that 2019 IRP.

Q Yeah.

A (Witness Grubb) I can -- I can continue my statement.

So the Commission approved Tugalo in the 2019 IRP. And part of that investment plan is to file at FERC when we're going to do investment work and work on those turbines and the aerators. And that's what we filed at FERC and that's what is at FERC.

So we did not in the '22 IRP turn over any cost-benefit analysis for Tugalo or any of the other four that were approved in 2019. And in the stipulation we've agreed to work with staff to do that for hydro facilities going forward in the future IRPs.

MR. PENDERGRAST: Okay. As to Exhibit K, the Google Maps photo, I move to tender that into the record, please.

MADAM CHAIR PRIDEMORE: So move.

(RCG Exhibit K was admitted into evidence.)

BY MR. PENDERGRAST:

Q And you said earlier that this other -- after water comes out of Lake Burton and -- Lake Burton is the storage reservoir of this system; is that right?

A (Witness Grubb) The majority of it, that's correct.

Q Okay. So after it is released out of Lake Burton, that water then runs on a run-of-river basis through the Lake Seed, Lake Rabun, Lake Tallulah, the Tallulah powerhouse, Lake Tugalo and Lake Yonah into the Tugalo River; is that right?

A (Witness Grubb) That's correct. They are modified run-of-river, which means we have to pass minimum flows. But there are opportunities where we can go above that minimum flow and increase the generation. So they're modified run-of-river.

Q Right. But Tugalo wasn't designed to be a storage reservoir; correct?

A (Witness Grubb) Not -- not in the way that Burton was, that's correct.

Q No. And so how would removing Lake Tugalo impact power generation at Lake Burton, if at all?

A (Witness Grubb) So it -- again, it more impacts Yonah and Tallulah. And then you've got to figure -- so these plants are designed to run as a system.

So the levels and the minimum flows from Burton through Burton Dam, down the Nacoochee, has to be factored into how Nacoochee operates. Nacoochee operates in the matter that it does going down.

So it doesn't mean that Tugalo specifically impacts Burton in and of itself, but the fact that it impacts Tallulah and then Terrora and Nacoochee, you've got to make sure that you take all of that into account.

Q The way --

A (Witness Grubb) Because they all impact each other.

Q The way the system is, as you've testified.

How much you release from Lake Burton is what really influences what happens the rest of the way downstream; right?

A (Witness Grubb) Well -- but they all -- my understanding is that the license at FERC has flow rates and minimum flows for all six facilities in that project. So it's a -- it's not just Burton and Nacoochee. You've got to understand the whole system.

Q Yeah. It's fairly elementary. Water -- water flows downhill; right?

A (Witness Grubb) It does. But, again, pressure differentials, elevation changes, how you're handling the flows from dam one, to two, to three, to four impacts it.

They've all got to be handled together, which is why they're licensed as one big project.

MR. PENDERGRAST: All right. That's all I have. Thank you.

WITNESS GRUBB: All right. Thank you.

MADAM CHAIR PRIDEMORE: Sierra Club. I think we'll do a little time test here.

Sierra Club, about how long?

MR. FABISH: Probably not more than 20 minutes.

MADAM CHAIR PRIDEMORE: Okay. SACE, about how long?

MR. BAKER: I am combining this panel's specific questions on their rebuttal testimony and stipulation. And so this is going to be my longest. About 50 minutes.

MADAM CHAIR PRIDEMORE: About 50?

MR. BAKER: Fifty.

MADAM CHAIR PRIDEMORE: Five zero?

MR. BAKER: Yes.

MADAM CHAIR PRIDEMORE: Okay. Well, at that point then we're going to go ahead and take a recess and we're going to eat lunch. I will see y'all back in here at 1:00.

(A recess was held from 11:57 a.m. until 1:00 p.m.)

MADAM CHAIR PRIDEMORE: Okay. Let's call the meeting back to order. Before I let Sierra Club begin, I have a housekeeping matter for Ms. Kysor. I've checked general counsel, and, yes, your hearing request can be honored and it can be addressed in the briefs.

MS. KYSOR: Thank you.

MADAM CHAIR PRIDEMORE: All right. Go ahead, Zach.

MR. FABISH: Thank you.

Good afternoon, Commissioners. I have just a few questions on two different topics for the panel. I would, if it's all right with the Commission, then like to defer to my co-counsel to ask a couple more questions on a different topic, if that's okay?

MADAM CHAIR PRIDEMORE: You may.

MR. FABISH: Okay. Thank you.

CROSS-EXAMINATION

BY MR. FABISH:

Q I'm Zach Fabish for the Sierra Club. Good afternoon, panelists. Thank you for taking the time.

I was able to trim some questions because they had been asked already earlier today. So if I could, I'd like to start with page 14 of the main panel's testimony, Grubb, et al.

A (Witness Grubb) Page 14 of the rebuttal for the main panel?

Q Yes, the rebuttal. I'm sorry.

A (Witness Grubb) Just clarifying.

Q Important clarification question.

Page 14, looking at lines -- starting about line 25 down toward the edge of the page --

A (Witness Grubb) Yes.

Q -- I think you mentioned this earlier, but just to make sure I understand. What you're saying here with this statement that "In the scenarios with carbon pricing, which can be used to indicate a range of potential impacts of future environmental pressures on coal plants," the carbon price in the unit retirement study that can be thought of in some ways as a bit of a proxy for unknown potential future environmental compliance costs; is that correct?

A (Witness Grubb) That's correct.

Q Okay. And given that in the past decade or so there have been numerous significant environmental rules that have placed cost pressures on coal mines, things like Cross-State Air Pollution Rule, Mercury toxic standard, ethyl limitation guidelines, coal combustion residuals, regional aides, many of which are discussed in the environmental compliance strategy document in this IRP, do you think it's likely that there will be future environmental compliance costs in the next decade or so?

A (Witness Mitchell) We do, Commissioners. And as -- as Mr. Grubb testified today, and Mr. Weathers, that was a factor that's taken into account when we consider the unit retirement analyses and our recommendations for -- in this IRP, we've included, as required in the environmental compliance strategy, numerous environmental rule makings that have occurred and are pending currently, so we do consider current and future requirements related to those existing assets.

Q And so as regards Bowen Units 1 and 2, retiring those earlier rather than later would minimize some of those environmental -- potential environmental compliance risks; is that correct?

A (Witness Grubb) That's correct.

Q Could I ask you to take a look at page -- I think it's 16 of the same rebuttal testimony? And coincidentally enough, it's also the last couple of lines on that page, starting on line 26.

A (Witness Grubb) Okay.

Q And this is talking about Bowen Units 1 and 2.

"If the units continue operation beyond 2027, the company would need to increase capital spend for these units to ensure their long-term reliable operation."

I know you touched on this briefly a little bit earlier, but could you elaborate a little bit, like what are those costs?

A (Witness Grubb) Yes. Good clarification.

So when we -- when we're speaking around those capital spend items, we're not specifically talking about environmental controls for environmental rules. We're talking around boiler replace- -- Boiler 2 replacements, any kind of capital to maintain the plan going forward.

Q Okay. And again, if Bowen Units 1 and 2 are retired earlier rather than later, those expanded capital costs could be avoided; is that correct?

A (Witness Grubb) Yes. So as we filed in the unit retirement study, we have a projection of capital spend to get those plants towards a 2027 retirement date or continue to operate. So there's a difference in those -- those capital budgets based on exactly what we're talking about.

If we know there's a retirement date, we can budget that plan capitally towards that date as opposed to 10 or 15 more years, you've got to put some more capital in them. For the plant components, not an environmental rule specific capital control.

Q And then am I correct in understanding that both the 2016 IRP, the order resolving that IRP, and the

2019 IRP, the order resolving that, capital expenditure limits were placed on various coal units?

A (Witness Grubb) That's correct.

Q Okay. Including Bowen 1 and 2 in the last --

A (Witness Grubb) Out of '19, that's correct.

Q Yeah, okay. Thank you.

If a decision as to Bowen Unit 1 and 2 retirement is deferred, would it make sense to impose capital expenditure limits to protect ratepayers in the meantime?

A (Witness Grubb) So we would not agree with that if there's not an early retirement date or a known retirement date. So in the last IRPs, both '16 and '19, you mentioned there were pressure on those plants and we felt like the odds were pretty high that we might come to the next IRP and ask for retirement. So it was limited in those three years until we made that decision.

So right now, if you're going to extend the lives for several years, it would be hard to do that because you've got to continue to rely on the operator, so we would say no.

Q Okay. Thank you.

The next set of questions I have, Mr. Mitchell, I think, may -- may center on you a little bit, but also on the -- the proposed stipulation as a whole.

So I'm looking at your rebuttal testimony at page 6, towards the top there. Starting about line 2 to 5.

A (Witness Grubb) You said page 6 of rebuttal testimony?

Q Yes. Mr. Mitchell's rebuttal testimony.

A (Witness Grubb) Oh. Sorry.

A (Witness Mitchell) Tell me the lines again.

Q Lines -- it looks like about line 2 through line 5, that last sentence starting with the word "while."

Do you see that?

A (Witness Mitchell) I do.

Q So you said, "While the rate is the appropriate forum to discuss the recovery of the costs associated with environmental compliance, it is appropriate for the detailed review and approval of the ECS and related costs to be completed within the IRP proceedings"; right?

A (Witness Mitchell) That's right.

Q So there are three things there: There's recovery, which is for the rate case, and then there's review and approval of ECS costs.

Those are the three things being discussed in that paragraph?

A (Witness Mitchell) In the IRP, yes.

Q Yes, okay. Could I ask you to -- and the whole panel to take a look at the proposed stipulation paragraph -- in both paragraph 15 and 17, which I believe kind of discuss those same things: The recovery, the review, and the approval of environmental compliance strategy costs.

And I guess my question is, since paragraph 15 talks about -- it says, "The Commission is not approving any costs and it is not necessary for the Commission to approve a specific budget for CCR compliance in this IRP proceeding."

And paragraph 17 says, "The costs have been reviewed in this proceeding and are acknowledged."

Could I just ask a big-picture question: How -- just square the circle, what is the difference between the statement in the testimony and these paragraphs in terms of when approvals would be happening in this proceeding or in the future proceeding?

A (Witness Mitchell) Sure. So, Commissioners, the -- the testimony reflects the company's belief that in compliance with the Commission's rules, we've provided an environmental compliance strategy to comply with federal and state rules.

Also, as ordered by the Commission, we've supplied the -- the associated costs to go execute on

that strategy. The company believes that the Commission has to consider both of those. When approving the plan, you need to consider the costs associated with that.

The company agreed with staff in the stipulation in paragraph 15. And the focus of paragraph 15 is an agreement that the environmental compliance strategy as updated in this IRP is approved, acknowledging that the costs have been reviewed, but also acknowledging that costs are not being approved here, while the focus of No. 17 in the stipulation is acknowledging that the detailed costs that the company provided to explain what it would take to implement our compliance plan have been reviewed in detail by the Commission.

So that's -- that's effectively the agreement there. And acknowledging that the company will bring and request recovery of those costs associated with execution of the plan in the 2022 IRP.

Q Thank you. That's very helpful.

So drilling down a little bit on the approval term, under the stipulation, are the costs approved in this IRP, or do they get approved in a different IRP, or do they get approved in the rate case, given that the stipulation says they are not going to be approved here or don't need to be approved here?

A (Witness Mitchell) Well, that's the -- the company and staff have agreed in the stipulation that the -- the environmental compliance strategy plan is approved subject to the Commission's adoption of the stipulation and the associated acknowledgement that there are costs associated with implementation of that plan.

The recovery of those costs, the company would seek in the rate case as we have done following IRPs where the Commission has approved our environmental compliance strategy for many years.

Q Okay. Thank you. I appreciate the explanation.

Could I ask you to turn to, Mr. Mitchell, your testimony at page 10. And this is, I think, the second question on the page referring to a new position by EPA regarding coal combustion residuals; is that correct?

I'm sorry. I should have specified. Your rebuttal testimony, page 10.

A (Witness Mitchell) I'm sorry.

Q I only have one set of testimony in front of me here, so it's easier for me to keep track.

A (Witness Mitchell) Where again on page 10?

Q The answer starting line 19. That Q and A at the bottom of the page there. That's where you discuss which characterizes a new position on the 2015 CCR rule;

is that correct?

A (Witness Mitchell) That's correct.

Q Okay. And just to be clear, the performance standards for CCR entitlement closure in place, those are from the original 2015 regulation; is that right?

A (Witness Mitchell) The performances standards in the 2015 rule for closure in place are unchanged.

Q Okay. And specifically, that includes -- and you're familiar with those regulations?

A (Witness Mitchell) Yes.

Q I figured you were, but I thought I'd ask.

And that includes for closure in place a requirement that free liquids must be eliminated from the CCR before the cap is put in place; is that right?

A (Witness Mitchell) That's correct.

Q Okay. And I believe that you testified in an earlier proceeding that post-closure for at least some of your coal combustion residual impoundments that are going to be capped in place, the CCR materials would still be in contact with groundwater; is that correct?

A (Witness Mitchell) I did; that's correct.

MR. FABISH: I think those are all of my questions, so I'd like to yield just a moment or two to my colleague, if that's all right.

MADAM CHAIR PRIDEMORE: Go ahead.

MS. ARIZA: Good afternoon, Commissioners.
Good afternoon, panel.
Isabella Ariza with the Sierra Club.

CROSS-EXAMINATION

BY MS. ARIZA:

Q I just have a few questions for you. And my questions are directed to the panel of Mr. Grubb, Mr. Mallard, Mr. Robinson, and Mr. Weathers.
Generally speaking, isn't it true that electric vehicle sales are increasing?

A (Witness Grubb) I understand that. We don't have the load forecast expert up here with us, but I understand that they are.

Q Okay. And over the next 10, 20 years, is it likely that there will be a significant increase in the number of electric vehicles in Georgia?

A (Witness Grubb) I would assume so, but not my area of expertise, nor anyone else's on the panel.

Q Fair. If there were thousands more electric vehicles on the road in the near future, which is a possibility, will that mean that Georgia Power customers could have a pretty substantial need to charge their electric vehicles?

A (Witness Grubb) So we have some estimates in the load forecast. I can't speak to exactly what they are. But, yeah. If electric vehicle sales grow, we will have more load to support, but we feel like we've got the planning in place from a generation and a power load standpoint to support those.

Q Okay. So you agree with me that EV -- the potential growth of EV would require charging infrastructure?

A (Witness Grubb) I believe it would. Again, that's not any of our area of expertise in terms of charging infrastructure.

Q Okay. But would you have any objections to including planning for such infrastructure in future IRPs?

A (Witness Grubb) So from an IRP standpoint, we really are looking at load and generation and demand side resources to meet those needs. I would think infrastructure may fall more in a rate-case-type application since it's not an IRP resource as far as --

COMMISSIONER MCDONALD: Is it going to be Georgia Power's responsibility to provide charging stations? Or is it going to be a consumer that purchases an EV to add that to their home or wherever they're going to do? Or is it going to be one of the major players in the -- in the fossil fuel business to expand their program? And if so, how are they going to resell electricity to somebody that needs to charge their EV?

WITNESS GRUBB: Great questions, Commissioners, that I don't know the answer to. In terms of -- I know there's a lot of discussions on that. I know the company is involved in the EV space, but I just don't have any expertise there in terms of in my daily activities.

COMMISSIONER MCDONALD: Go back to my original question, the responsibility.

WITNESS GRUBB: So we obviously have the responsibility for supplying the energy and capacity to support those chargers, whoever's they are, if they're in our territory. But I know that we're working on chargers, but I can't speak to exactly who all has the rights and who's building those chargers out there.

I think that's a lot of active discussion at this time. I'm not sure if anybody else on the panel has anything to add, so...

WITNESS WEATHERS: Not really to the infrastructure; but as Mr. Grubb said, our load forecast does include some amount of electric vehicle growth. The next panel would be the best panel to ask that to; but from a planning

perspective, having the capacity on the system to be able to serve the charging loads is mostly what we are interested in from a resource planning perspective.

WITNESS ROBINSON: I'd like to speak -- we are looking at the needs to expand the system and provide, particularly when you have last-mile centers and large Amazon centers that come in and put a lot of demand on the system. We see a need to upgrade those feeders to provide that capability. But that'll be -- those are topics more appropriately discussed in the rate case.

BY MS. ARIZA:

Q   Thank you. And, Mr. Grubb and Mr. Robinson, do you plan on bringing that up in this rate case, in the 2022 rate case, some of these issues?

A   (Witness Grubb) I don't know. I'm not involved in the rate case development; but I would assume if we've got any programs related to that, it would be in there, but I'm not personally familiar with it.

A   (Witness Robinson) The rate case will be filed on Friday.

MS. ARIZA: Thank you. Those are all my questions.

A   (Witness Grubb) Thank you.

MADAM CHAIR PRIDEMORE: Thank you, Miss Ariza. Southern Alliance for Clean Energy and Southface Energy Institute. Bobby? Bryan? Katie?

MR. BAKER: Good afternoon, panel.

PANEL: Good afternoon.

CROSS-EXAMINATION

BY MR. BAKER:

Q I have got questions initially focusing on the stipulation itself.

A (Witness Grubb) Okay.

Q And then I'll shift over to your rebuttal testimony. So --

A (Witness Grubb) Okay.

Q So let's start off with some preliminary questions about the stipulation. Did any of you engage in the negotiations of the stipulation?

A (Witness Grubb) Not with the other parties. We obviously were consulted on topics and issues, but we were not actively in discussions with other parties.

Q Okay. Do you know who negotiated on behalf of Georgia Power and the advocacy staff, the stipulation?

A (Witness Grubb) No. It would be counsel.

Q Counsel?

A Or lawyers. Yes. So Troutman and --

Q Anybody here on this table?

A (Witness Grubb) There's a few of them. Yes.
Q Raise your hands.
A There are some.
Q Hands raised? Mr. Marzo did it all? Okay.
Anybody from staff, do you know?
A (Witness Grubb) I would have to let staff answer that. I'm assuming Mr. Thomas and others, that their counsel would be involved.
MADAM CHAIR PRIDEMORE: I'm interested, Mr. Baker. What does it matter?
MR. BAKER: Just preliminary. Wanted to make sure that the folks from the advocacy team were involved in -- seeing if they were involved in the negotiating, because they signed it.
MADAM CHAIR PRIDEMORE: Okay. All right. All right. I'll allow it. Okay. Just interested.
MR. BAKER: All right.
BY MR. BAKER:
Q Were any of the intervenors invited to participate in the negotiations with Georgia Power and the advocacy staff?
A (Witness Grubb) Again, I can't speak to all the conversations, but I think it's been pretty common knowledge that the company is willing to speak with intervenors and work towards resolution in cases as we've

often done.

Q But you're not aware anybody was actually invited to participate in the --

A (Witness Grubb) I can't speak to what discussions were had. I didn't personally have them.

Q All right.

Let's turn to the specifics of the stipulation. Starting first with paragraph 6 of the stipulation.

The PPA for Plant Dahlberg Units 1, 3, and 5 doesn't start until 2028. Why is it necessary to approve the PPA now rather than waiting until the 2025 IRP?

A (Witness Grubb) You're asking about that specific PPA?

Q Yes, sir.

A (Witness Grubb) So that specific PPA has been executed and is here for approval in this IRP. If it's not approved here, then that PPA is no longer an option. So we can't wait until 2025. We executed that PPA as part of the capacity RFP to meet the needs in this IRP filing.

So if we defer that decision, then that contract is really null and void. So it's actually not a wait and make that decision. It is, it would be a decertification or a not approval of it. So it -- we've looked again at that '25 to '28 range, so that was a resource that came on in '28, met the needs of the IRP, and that's why we're seeking certification.

Q The staff testified that the PPAs would need to be revisited if commissioners decide to keep Bowen Units 1 and 2 open beyond 2027. Does the stipulation anticipate this option?

A (Witness Grubb) So I can't speak for staff, but the stipulation states that all six PPAs are being recommended by the stipulating parties for approval by the Commission. The Bowen 1 and 2 is a separate paragraph and a separate decision.

And so I can't speak directly for staff, but the stipulation is to approve all six PPAs, not conditional on the Bowen paragraph. They are separate paragraphs.

Q But hypothetically, if the Commission makes a decision not to retire Bowen Units 1 and 2, that's 1,400 megawatts. Won't that have an impact on the need for all six natural gas PPAs?

A (Witness Grubb) So it would have an impact that we spoke some about this morning, in '29 and '30. '28 and beyond. So it would there. But, again, Commissioners, we see a lot of value in those six PPAs. They're great -- they're great responses from the market. We have really good capacity pricing, really good firm transportation value.

Any of the PPAs that are not approved here increases the amount of megawatts that we will have to procure in the '30s in a period when we're -- I think it's very highly likely that we will pay more, either for those assets, for other assets in the market, or possibly have to have new construction at those assets.

So it increases the needs for '28 and beyond but not up through that point. But again, we see value there; and again, not to speak directly for staff and their testimony, but both of our parties and the other stipulating parties agreed to the certification of all six.

Q Okay. If -- if, hypothetically, in a hypothetical situation, if the Commission were to decide not to retire Bowen 1 and 2 as the company is recommending, and all six natural gas PPAs are approved in this, would the actual PPAs be used during the next few years? Is there actually a need for them to actually turn on and generate electrons during that time?

A (Witness Grubb) Absolutely. I mean, if you look at it now, Commissioners, we are -- we currently have more megawatts than our target reserve margin now, and we will use those assets to serve load. That fleet is available for economic dispatch, so as we add those six PPAs, they absolutely will generate when they are the most economic resource to do so.

A (Witness Weathers) And as we discussed with Commissioner McDonald this morning, currently, even with short-term natural gas prices being elevated, combined cycles are still economic to operate. They're still more economic than many of our coal units, because coal prices also are elevated.

There's issues in the coal market with the mining, with the delivery of coal. All of those are causing increases in prices. So absolutely, these power purchase agreements will operate and serve customers. In fact, the one that you're asking in particular about with the Dahlberg Units, Mr. Baker -- I mean, the timing of that coming in very well aligns with the company's capacity need. So it will not only be needed for energy purposes but also for capacity purposes.

Q Well, let me refer you back to Witness Goggin who raised the prospect of converting Plant Bowen Units 1 and 2 to synchronous condensers.

What is the company's reaction to that proposition?

A (Witness Robinson) Actually, going back to my testimony in the -- in April, I actually brought that up. The -- the prospect of converting 1 or 2 or both, preferably 1, because it's on the 230 KB system, to a synchronous condenser. That doesn't give you the capacity. It allows you to produce and absorb bars which supports voltage and helps move megawatts across the system. But we are interested in looking at that conversion, and we are actively talking about it internally.

A (Witness Grubb) And, Commissioners, when we -- when we talked about the North Georgia reliability resiliency plan, those are the types of things that we'll be looking at as we look at transmission and generation, is exactly what Mr. Robinson just spoke to. It would be one of the items we would -- we would continue to study.

Q So that's an option that would be actively studied if the Bowen units were kept?

A (Witness Robinson) I am personally actively pushing it.

Q Do you think it's going to save ratepayers money if those units are -- one or two of those units are converted to synchronous condensers?

A (Witness Robinson) That would be part of the evaluation. There's a cost associated with that. It would become a -- a transmission asset would have to be operated and maintained.

I mean, you take the boiler off, you leave the term and generator or just the generator there and you use the exciter basically to move the position of the unit to either absorb or produce bars. It's not free. So there's no fuel cost, but there's a cost to operate that. That would have to be evaluated along the process.

Q Is there any other unit in the system today that is operated as a synchronous condenser?

A (Witness Robinson) Several of our hydro facilities are operated as synchronous condensers. They have the ability to do that as well. Some of the newer combined cycle units -- I'm not sure if McDonough has this capability, but newer combined cycles have the ability to uncouple and run as a synchronous condenser.

Q Five of the six PPAs represent affiliate transactions within the Southern Company that will require subsequent approval by FERC.

What happens if FERC rejects any of those affiliate transactions?

A (Witness Grubb) So we would have to -- again, I don't know what the odds of that are; but if that were to happen, they don't take effect until '25 or one of them until '28, so we would have to relook at our capacity needs and factor that into our next solicitations.

I don't -- depending on which ones, I don't think it would drive us to an immediate need, because

they don't start until '25. But we would just have to look our end over and then reflect that into our normal planning in terms of looking at our next capacity need.

Q Do you know on average how long it takes for FERC to make that kind of evaluation or review?

A (Witness Grubb) I don't.

Q Did the staff and Georgia Power consider including additional consumer protection mechanisms to the six natural gas PPAs?

A (Witness Grubb) In terms of --

A (Witness Weathers) Do you have any examples of that?

Q Yes, I'll give you an example. Did you consider including an upper limit on fuel cost recovery for the PPAs and in the event that natural gas prices increase dramatically or fuel supplies are disrupted?

A (Witness Grubb) No. The RFP was conducted with the Commission approved PPAs, and no such conditions were in there.

Again, one benefit of gas resources are they're dispatchable, all right, so you're absolutely able to take into account where they are in the economic dispatch stack.

So, no, the -- the -- there were no such things like that in the proformas that were approved as part of

the RFP and then executed with those counterparties.

Q Is there a level or a cost prohibitive level for natural gas that would make it uneconomical to run those units?

A (Witness Weathers) I -- I think likely not. I mean, what we've seen is that with the challenges that the coal industry is facing these days that -- that coal deliveries are becoming constrained and the ability to get coal to plants on an as-needed basis is more difficult than it was in the past. So it requires longer term contracts. It requires higher priced contracts.

So the ability of the system to dynamically switch from gas to coal on a daily basis is just more limiting than it used to be.

In addition, as I mentioned, as natural gas prices have been higher in recent months, coal prices didn't stay the same. They're higher as well. And so we expect, even if natural gas prices were to have some spikes within the term of the contracts, like they're doing now -- again, these are several years away when we expect prices to come back down, but there will be a volatility. And even if they were to have some short-term spikes, we do expect that natural gas to continue to be economic and used widely across the system to serve customers.

Q All right.

A (Witness Weathers) The company has the ability to hedge gas, which is a positive. So we can reduce some of the risks through financial hedges. But we do expect natural gas to be economic across all of our planning scenarios, even our high gas scenarios.

Q By 2025 is what your projection is?

A (Witness Weathers) By 2025 and well beyond that into the future as well.

Q Do you agree the Allegheny standard FERC applies and its affiliate abuse analysis is designed to assure the company does not choose to enter a high cost transaction with an affiliate when less costly options are available from nonaffiliated suppliers?

A (Witness Grubb) I agree 100 percent and agree that the Commission's RFP rules implement that Allegheny principle, our RFP process with independent evaluator absolutely takes that principle into account, and the IE monitors that entire RFP. And so the affiliate PPAs were the best result from that capacity RFP, and it was handled under the RFP rules from this Commission to make sure that the affiliate treatment was -- was handled per FERC principles and requirements.

Q Did the independent evaluator issue a legal opinion as to the appropriateness?

A (Witness Grubb) He has filed a report in this IRP for staff conducting that entire capacity RFP under the Commission's rules and those principles of affiliate transactions.

Q But wouldn't that be more a legal issue rather than a general issue for the independent evaluator?

MR. HEWITSON: If Mr. Baker now thinks this is a legal issue, he shouldn't have asked the panel. So I think now that he's asked the question, they can answer it.

MADAM CHAIR PRIDEMORE: Sustained. I don't -- they're not attorneys, Mr. Baker.

MR. BAKER: No, no, no. I'm asking if --

MADAM CHAIR PRIDEMORE: You're asking for a legal opinion, though.

MR. BAKER: No, I'm not. I'm asking if the independent evaluator is issuing a legal opinion basically saying that the company complies with the --

MADAM CHAIR PRIDEMORE: But if they're not attorneys, how will they recognize a legal opinion?

MR. BAKER: Because they would have seen -- they indicated that they've seen a report.

MR. HEWITSON: Let me put it this way. The independent evaluator appeared in this proceeding

and sponsored testimony. If Mr. Baker had questions regarding the nature of that report, he could have asked the independent evaluator. Asking this panel in rebuttal doesn't seem appropriate.

MADAM CHAIR PRIDEMORE: Sustained.

BY MR. BAKER:

Q In your opinion, could a Commission order setting an upper limit on recovery of fuel cost for these PPAs adequately protect ratepayers from the risk of natural gas fuel price increases and volatility?

A (Witness Grubb) I don't know that the Commission has done that before. I mean, the Commission has lots of authority to do those types of things.

But again, the -- as Mr. Weathers noted, we don't expect the natural gas prices to stay up for a long time. That is the nature of a generation resource. You make it on the best information at the time, and we can dispatch based on those economics.

So I -- I don't believe the Commission -- I wouldn't recommend the Commission do it. I don't think we've done it in the past. But, again, the Commission can -- can do as they note.

But, again, we see those natural gas PPAs from 2025 to '35 or even into '38 being the most beneficial resources for customers that allows us to retire the coal units that we're recommending for retirement.

Q Thank you.

Turning to paragraph 19 now, dealing with the CARES program tariff design negotiations.

A (Witness Grubb) This is in the stipulation; correct?

Q Yes, sir.

A Number 19?

Q We're still in the stipulation --

A (Witness Grubb) Just making sure.

Q -- paragraph 19 of the stipulation.

A (Witness Grubb) Okay.

Q How did the company and staff identify which intervening parties to include in the negotiations on the program and tariff design details?

A (Witness Mallard) So I can't speak to specifically how those parties were identified. But what I can tell you is those intervening parties represent the customers who are likely participants in these programs.

This really, to me, just memorializes what Georgia Power always does in our -- in our program design, and that is to seek feedback from the types of customers that the programs are designed for and that they will participate in.

So I'm not specifically aware of how they were chosen, but I can tell you those intervenors do represent customers who we feel like are target participants in the program.

Q Will any other parties other than those listed be able to participate?

A (Witness Mallard) I can only speak to what's in the stipulation, and it calls for those particular intervening parties to be involved in those -- in those negotiations.

Q Will there be geographic limitations, such as a North Georgia limitation, imposed on either of the 1,050-megawatt renewable RFPs?

A (Witness Mallard) No. As part of the stipulation, there will be no geographic restriction on the part of the state or actually the entire country from which bids can be received.

A (Witness Robinson) But as we mentioned in the stipulation and the testimony, we are interested in working with staff to develop a process for facilitating renewable development in North Georgia. We feel that there's several reasons to do that. Number one, provide us the time to build the transmission to move back south. And then secondly is for geographic diversity.

As happened last week, we had very sunny days here in Atlanta. We had storms in South Georgia. We've got to protect against that event happening in the future.

Q All right. Turning to paragraph 29 of the stipulation. Paragraph 29 acknowledges there are methodological differences that still need to be worked out between staff and the company after this IRP and approved by the Commission by June 30th, 2023.

Will any parties to this IRP other than the staff and company be invited or allowed to participate in those conversations?

A (Witness Grubb) So we discussed this some this morning, I believe. And, again, for the purposes of the stipulation, it would not. But we've -- we've often been open to conversations with other parties and the interest in the renewable -- the renewable cost benefit or the renewable integration study. And then also testimony filed in the IRPs is an opportunity to have your position stated, too.

So always open to discussions, but in terms of the specific meetings with staff, it would just be us and staff.

Q Does any of the language in the stipulation imply that staff endorses the methodology Estrapa used in the renewable integration study, particularly the arbitrary definition of flexibility violations that is not correlated to the relevant NERC standard?

A (Witness Grubb) So I'll -- I'll disagree with arbitrary there. I mean, what we looked at in the renewable integration study were measures that indicate you could have reliability considerations. And I'll let Mr. Weathers speak to that more.

And also I can't speak for staff, that they agree with everything. I mean, they filed testimony, and the stipulation notes that there are some sections in that study that we're going to meet with them on.

So we will work with staff as the two parties on those methodologies, and then we'll let Mr. Weathers speak a little more to the -- to the NERC reliability standard.

A (Witness Weathers) Yeah. I agree with Mr. Grubb, and I can elaborate if you have questions. But I would also disagree, as Mr. Grubb did, that the -- in modeling that was done in SERVM is contrary -- it's arbitrary and contrary to the NERC standard. So the modeling we did in SERVM was to model the system dispatch on a 5-minute basis.

So it is an approximation for real-time dispatch. We don't have the model that can dispatch units on a 6-second basis like we do in real-time operations. But we approximated it using a 5-minute basis, and if we -- and the model planned for the system to be able to balance load generation every 5 minutes. That's what NERC requires for us. That's when what our operators do.

Now, certainly, there are NERC metrics that they have different time periods, but it doesn't mean that with any 5-minute -- within any 5-minute basis, our system operators can let the system go and choose not to take action and be pulling in energy from the grid.

So if that happens, we have to pay that back in kind. That costs our customers money. So our practice in real-time operations is to balance load generation. There are certain metrics we have that measure that. And that's what we -- that's in our modeling for the renewable integration study. Those are the exact things that we tried to model. We did them on a 5-minute basis. We thought that was a reasonable appropriate approximation.

Q Do you think the modeling will be modified in the future to have a shorter time period that it's based on? Rather than 5 minutes, maybe, you know, 3 minutes, 2 minutes, in the future?

A (Witness Weathers) We don't have, necessarily, plans to do that. But I think the modeling -- we'll continue to look at it and evolve it and look at the

benefits of doing that. I'm not sure how that helps the situation. But we will look at it.

But we do think that the 5-minute basis is a very good approximation of real time. So want to distinguish between hourly integrated modeling and at 5 minutes, really have to have the flexibility of generators to dispatch.

And that was what was identified. On an hourly basis, you may have enough capacity on the system, but if that capacity is not flexible enough to move in a 5-minute or lesser duration, then you're not going to be able to keep up with the rapid changes that solar ramping and solar intermittency introduce on the system. So that's the basis of that modeling. That's the basis of the integration cost component of the renewable cost benefit framework.

Q Thank you.

Will Georgia Power and the Commission staff engage with members of the demand side -- demand side DSM working group on the substantive details related to competitive analysis of DSM at such times that stakeholders' input can be considered while the company is developing its modeling approach?

A (Witness Grubb) So that was relating to DSM?

Q Yes, sir.

A (Witness Grubb) That's best answered by Panel 2. I think you were asking around modeling of demand-side management?

Q All right.

A Yeah. That would be Panel 2.

Q Okay. I'll ask them that question.

A (Witness Grubb) They'll be happy I teed it up for them.

Q Okay. Well, you know, they already know it's coming their way, so they'll have a good answer, I'm sure.

A (Witness Grubb) I'll bet they're working on it right now.

Q Okay.

All right. Now, turning to your prefiled rebuttal testimony. Done with the stipulation-specific questions, but there may be some references to stipulation, but --

A (Witness Grubb) Okay.

Q -- getting to your specific prefiled testimony. Beginning -- I'm going to refer you to page 16, and you make the case for why Plant Bowen Units 1 and 2 should be retired and decertified. And you say that the -- "The economic analysis conducted as a part of the unit retirement study in the 2022 IRP indicates that continued

operation of Plant Bowen Units 1 and 2 is uneconomical and not in the best interests of customers."

Do you still stand by that testimony?

A (Witness Grubb) So we've noted that this morning. That is what our studies revealed. Staff's analysis showed a little bit different. Showed it's a close call. And we both agreed that in that situation it's a Commission decision of Bowen. But, yes, our economics still indicate that's the case. But it is -- it is a consideration for the staff -- for the Commission to take into account.

COMMISSIONER MCDONALD: I go back again one time. When was this decision made?

WITNESS GRUBB: So when we filed -- so we would have used fuel prices and planning inputs the end of last calendar year, so we filed in January.

COMMISSIONER MCDONALD: Thank you.

WITNESS GRUBB: Yes, sir.

BY MR. BAKER:

Q And you also indicated that, "If the units continue operation beyond 2027, there's going to have to be additional capital spends."

Wouldn't that make the units even more uneconomic based on your current analysis?

A (Witness Grubb) So that statement is based on what we would have had in the unit retirement studies. So when we -- when we look at the numbers we provide in the unit retirement study about some budget savings that we could see on the capital side, that was based on a 2027 retirement.

The numbers we're saying that we would most likely have to spend if we continue to keep those units would have been similar numbers that are in the 30-year study. So it's a continue to operate budget, and that's on a capital from reinvesting in the plant to allow for 30 years of running versus kind of a glide-path budget that we would say. So those numbers were in the unit retirement study.

Q If the record includes only two findings, the staff's concluding it's a "close call," and Georgia Power's that favors retirement at the end of 2027, what evidence is there in the record to contradict those analyses and justify a policy decision to keep Plant Bowen Units 1 and 2 past 2027?

A (Witness Grubb) So not to speak for commissioners; they can do that themselves. But the commissioners obviously have things that they consider in their decisions that may not be captured in economic analysis from the company or from staff. And so, again, a lot of impacts from these types of decisions, and we recognize that for the Commission.

And so not to speak directly for staff, but we both agreed that the Commission can make that decision and factor in what the commissioners themselves feel like they need to factor in to that decision.

Q All right. Thank you.

At page 19 of your prefiled rebuttal testimony, you state, "Long-term forecast of natural gas prices which encompass the period in which the energy is delivered to the company from the 2022 through 2028 capacity RFP, the PPAs indicate that recent natural gas prices may be a short-term phenomenon."

NextEra announced last week that Florida Power & Light will install 90,000 megawatts of solar, 50,000 megawatts of storage, and produce green hydrogen as fuel for repowering 16,000 megawatts of existing fossil gas plants. NextEra seems to be using entirely different forecast for natural gas prices than Georgia Power.

Is it possible NextEra's natural gas price forecast is correct, and you may be wrong?

A (Witness Weathers) Mr. Baker, I did see the article. I did see the announcement from NextEra. I didn't see any -- I don't recall any reference to their natural gas price forecast.

Do you have information on what price forecast they used?

Q No, I don't. But obviously, if they're turning towards renewables and away from natural gas, which is their prime generation fuel, that might indicate that they have some concerns about the pricing.

A (Witness Weathers) Well, I don't know if they do or don't, but I also saw them connecting that to a net-zero strategy, or I think they called it a real-zero strategy that they have. So I think there's a policy implications to their strategy there.

Our natural gas forecast -- our long-term natural gas price forecasts, we adopt the annual energy outlook that the U.S. Government's Environment- -- excuse me -- Energy Administration -- Energy Information Administration uses.

And so the one -- for the budget '22 IRP, we use one that's -- the AEO that was produced in 2021. Well, they recently produced the 2022 update. The 2022 version of the AEO back in March. The long-term natural gas price forecasts are still about the same as they were in their 2021 version.

So the next time we do an annual planning update, which will be this fall, will pick up the new gas price forecasts, but they haven't changed. They're essentially unchanged from where they were from last year's forecasts. So we do continue to have a lot of confidence in our natural gas, the range of natural gas forecasts that we're using for planning purposes.

MADAM CHAIR PRIDEMORE: Mr. Baker, NextEra has gas PPAs in their strategic plan as well, so I think you probably just read the article with the assumption that they were not as bullish on natural gas as they are. But they have a diversified approach, just like Georgia does.

MR. BAKER: Thank you, Madam Chairman.

BY MR. BAKER:

Q Panel, what remedies are included in the PPA terms if natural gas fuel supplies are disrupted during the contract term?

A (Witness Weathers) Well, so -- and not in terms of remedy. But these plants do have firm natural gas transportation, which means that the owners have secured in some of these cases, the Southern Company Services on behalf of the affiliate, has secured the capacity for natural gas on the pipelines to be delivered to us. So it's like having a reservation, and so they had the reservation. We can deliver that natural gas.

And so disruptions would not be the normal course of business when you have firm gas transportation.

So that gives a lot of assurances to customers that the gas can be delivered to the plants for generation purposes when it's needed.

Q Is the company supportive of a mechanism that would limit the fuel costs that can be recovered under the PPAs in the event that natural gas prices increase dramatically during the contract term if so ordered by the Commission?

A (Witness Grubb) No, we are not in favor of that. Obviously, the Commission can do as they need, but we've never had those in the past and were able to dispatch the system, the diverse system, based on what's happening in the fuel markets. Not just gas.

Q Okay. The company believes and it is not appropriate to request that Alabama Power Company and Mississippi Power Company share the cost of the Tall Wind and integrated hydrogen microgrid project because they primarily benefit Georgia Power and the state of Georgia.

While the projects will be located in Georgia, and the minimal generation may be used in Georgia, isn't the real value of these research projects the operational and technical data developed and gathered, not some meager amount of generation that will be produced?

A (Witness Grubb) No. I would -- I would disagree with that. I mean, it's not just the megawatt hours, but the benefit to Georgia and our customers for those two pilots. So if you're thinking about the Tall Wind, we see that as a resource that we want to learn about because it could benefit Georgia Power customers in the future. Very complimentary to solar.

So it's not just the learning of the construction of the tower or the generation from this pilot. We see that resource potentially having a lot of potential to serve Georgia Power customers. And the same thing on the hydrogen microgrid. A lot of use cases that we can study that could benefit Georgia Power customers down the -- down the road.

Sure, there's always learnings across the system, but we see hydrogen and a potential role for hydrogen and getting some experience in hydrogen and wind being resources that can benefit Georgia customers down the road.

COMMISSIONER MCDONALD: How long is your PPA contract with Oklahoma and New Mexico on wind?

WITNESS MALLARD: Those are 20-year PPAs.

COMMISSIONER MCDONALD: And we're in what year of it?

WITNESS MALLARD: Seven or eight, subject to check.

COMMISSIONER MCDONALD: What -- what makes the difference when that PPA was signed by the company as far as the wind is concerned and knowing at that time that we don't have the sustained winds, that we now come to a place where we think maybe there are sustained wind --

WITNESS MALLARD: That's right. That's right because --

COMMISSIONER MCDONALD: Has the climate changed that much?

WITNESS MALLARD: No. It's the location of where the -- where the turbines are. And so think about that wind is imported from Oklahoma, which is really the wind belt, if you will. The wind resource out in the midwest is really good.

And so at traditional hub heights, those wind resources are able to produce wind at a price that's economic for customers. Even wheeled all the way from Oklahoma to Georgia. What we're going to test here is new technology that allows those hub heights to get up even higher.

So even though our wind resource is not quite as good here in Georgia as what they have in the Midwest, you get up high enough, 140, 150 meters, and use some new technology that allows the wind turbines to cut in at a lower speed, the projections, the studies that we're seeing indicate that it has got a real good chance to be economic for customers here in Georgia. Not necessarily from another part of the country and wheeled in.

COMMISSIONER MCDONALD: When you're looking at pilot projects with microgrid and hydrogen, aren't there programs that you're already participating in at Georgia Tech and other institutions in those studies?

WITNESS GRUBB: So on the microgrid we are. I think we're looking at six or seven different technologies at the Georgia Tech microgrid. None of those are hydrogen. So what we are looking at is when we look forward towards, you know, technology advancement, what role hydrogen may play, this is just a chance for us to leverage a lot of actual outside funding and get a 60 plus million dollar project for a cost to customers for about 10 percent of that.

It gives us a chance to get some experience with the electrolysis of hydrogen, which is the production of it. Also being able to look at how it can charge vehicles.

So it's a very vehicle-based pilot project but gets us experience with hydrogen, which could eventually be a long duration storage option for us that allows us to further integrate renewables. And so that's really what we're looking at on the hydrogen side is getting some experience but really leveraging that funding that we've got from outside parties.

COMMISSIONER MCDONALD: Wouldn't it behoove the Southern Company to do that under their umbrella as a nonregulated entity of the Southern Company, because the study that would come forth, as Commissioner Baker kind of indicated, you know, it's going to have -- that technology is going to affect all the -- all the utilities under the Southern Company umbrella at some point in time.

WITNESS GRUBB: Well, I think -- I think a few -- a few points there. One is we're looking at gaining a lot of knowledge of how it can work with zero emission vehicles, which Georgia Power has a focus on that. So it will benefit us on what we might can do on either electric vehicles charged from hydrogen or hydrogen vehicles. So that's one part of it.

The other part of it, even though it's a small part of this pilot, there is a fuel cell here, there's the electrolysis of hydrogen. So we think further down the road on storage and renewables, there's some benefit that hydrogen can develop as a long-term duration for storage.

And as Georgia Power on the system, we've got a lot more renewables than any of the other operating companies, and so we're a lot -- we're very focused on what those long duration storage options may be. And again, this is a chance for us to dip our toe in the hydrogen world.

COMMISSIONER MCDONALD: You can't steal some of that information from other of the hydrogen projects that have gone forth in the state of California and other places like that? Can't you steal that information rather than produce it yourself?

WITNESS MALLARD: I'm not -- I'm not familiar with those exact projects.

COMMISSIONER MCDONALD: We stole a lot of solar stuff from them, I can tell you that, back in the late --

MADAM CHAIR PRIDEMORE: I'd like to be clear that the commissioner is not recommending that we steal anything from any other state. I just want to be clear about that.

WITNESS GRUBB: Pennies learned, steel learned. And I think, again, gaining the experience of electrolysis here, you know, as we look forward to having continued renewables on the system, there are going to be hours where we might have to curtail that solar.

So any things that we can look at that allow us to use that solar energy, whether it's charging storage or using it as electrolysis of hydrogen. Even though this is a small pilot, we see that as a technology that we need to focus on that could potentially help the customers.

COMMISSIONER MCDONALD: For a matter of the record, I'd like to remove the word "steal" and put in "absconded."

MADAM CHAIR PRIDEMORE: Thank you, Commissioner.

MR. BAKER: Uncompensated appropriation.

MADAM CHAIR PRIDEMORE: I would like to remind, Mr. Baker, though, that the discussion of rates is for later on this year.

BY MR. BAKER:

Q But wouldn't you agree that the experience from the -- and the data and the information gathered from these pilot projects is very valuable and it's very transferable?

A (Witness Mallard) It is; but for the Tall Wind

demo, for example, understanding how that wind resource works, particularly here in Georgia, understanding how it interacts with our particular generation mix here in Georgia. We are a leader in solar. We're going to be the first to need this complimentary resource. We also get to design the project just exactly how we want it to test all the things that we want, so we can maximize the learnings to make sense for the resource here in Georgia.

So, yes, a lot of the learnings are transferable, but it's -- it's really appropriate for this project to be a Georgia Power project so that we can maximize that value for our customers.

MADAM CHAIR PRIDEMORE: Isn't a big portion of this, though, the fact that Georgia has the Atlantic coast and the other operating companies do not?

WITNESS MALLARD: Not specifically for this onshore wind resource. But it does go to the point, Madam Chair, that our wind resource is different. It's different in South Georgia as Alabama as Mississippi. And so we're looking at testing this wind resource sort of land based in -- in South Georgia. We haven't identified the location yet.

But the wind resource is different here, and that's -- we do want to test the wind resource, we want to test how the towers go into the ground, the

different geology here. So all of those things are important for us to learn how it works best in Georgia.

BY MR. BAKER:

Q   If the Georgia Power ratepayers are going to pay for this, for these pilot projects, will any information or data gathered or developed from these projects be shared with Alabama Power, Mississippi Power, or any other organization, now or in the future?

A   (Witness Grubb) So I don't know about the data. But I think when you look at Southern Company R&D, there's projects that other operating companies pay full cost for that we -- that we share information from as well.

Again, I think Mr. Mallard's hit on the -- the main driver for these pilot projects is for Georgia Power customers and what we see as technology options to test and gain experience with for Georgia Power customers.

But there's -- there's learnings, Southern Company affiliates across the operating companies, I mean, that's just one of the benefits of having a company.

A   (Witness Mallard) Beyond as well, first, we have learnings that will be shared not just across our affiliates but across the industry as well.

As Commissioner McDonald alluded to, sharing knowledge and information across jurisdictions from utility to utility is wholly appropriate and it's a way for us to move the ball forward as it relates to -- to virgin technologies.

Q I think that's great. I think you ought to share it. I thank your friends in California who share how they've merged, you know, generation and storage. I'm just -- my concern is having Georgia Power ratepayers pay for it all.

Let's move on here. At page 37, you state: "Outside stakeholders such as developers and Commission staff regularly attend the quarterly Southeast Regional Transmission Planning meetings.

"The stakeholders' input on transmission plans through the quarterly meetings, information on how to participate in the meetings is posted publicly on the company's open access same time information system, or OASIS, website and through the Southeast Regional Transmission Planning website."

To your knowledge, have either the PSC staff or Georgia Power Company ever submitted transmission study requests for Southeast Regional Transmission Planning planners to consider transmission needs being driven by public policy requirements such as the EPA's coal combustion residuals and effluent limitation guidelines, which are now driving coal plant retirements requested in this IRP?

A (Witness Robinson) Well, I think the stakeholder processes that are referred to here are for outside of the planning world. We are in this -- at Southern Company Services, we are the transmission planners. We are planning the system.

The regional planning stakeholder group that exists is for stakeholders to input requests, concerns, through the SERTP process. We participate in SERTP as planners on a quarterly basis. The stakeholders, who are outside stakeholders, transmission owners, developers that participate in SERTP through the quarterly process.

Q Are you aware of the study request process?

A (Witness Robinson) Generally aware, yes.

Q Generally?

A (Witness Robinson) Yes.

Q Are you aware that no study requests were submitted to the Southeast Regional Transmission Planning from 2018 to 2021?

A (Witness Robinson) I'm aware of that.

Q Okay. Was it a mistake not to submit the study request to SERTP process?

A (Witness Robinson) Again, Southern Company nor

Georgia Power would be submitting any request. We are the SERTP. We are the planners. The stakeholder group is for outside entities to make those requests. And my understanding is since 2010 there have been no requests made of stakeholders through the process.

But it is not Georgia Power or Southern Company Services' responsibility or the mechanism is there for us to request. We are the planners.

Q Okay. So you can't ask yourself?

A (Witness Robinson) Correct.

Q Are you aware the SERTP regional transmission plan does not currently provide estimates of the cost of transmission projects proposed and ultimately included in the plan?

A (Witness Robinson) It's been a while since I've been at a meeting. Subject to check, those costs are not included.

Q Are you aware the SERTP process restricts public access to essential planning information that is often open to the public and other transmission planning regions?

A (Witness Robinson) It is protected for several reasons, but mainly because of CEII protection.

Q Are you aware that on March 24, 2022, FERC issued an order pursuant to Section 206 of the Federal

Power Act instituting an investigation into whether Southern Company Services and Georgia Power's formula rate protocols are unjust, unreasonable, unduly discriminatory, or preferential or otherwise unlawful?

A (Witness Robinson) I am not specifically aware.

Q Anybody on the panel?

A (Witness Mallard) No.

A (Witness Grubb) No, sir.

Q What is your understanding of FERC's concern regarding the Georgia Power Company's transmission planning processes and rates as described in the FERC order?

A (Witness Robinson) I don't know how we can answer that. We just said we're not aware.

Q Could you explain, what is the primary reason the stipulation excludes the collaborative transmission study process proposed by Staff Witness Chiles?

A (Witness Robinson) The company does not believe that a collaborative -- such a collaborative process would be helpful. We have a very robust planning process here in Georgia and the Southeast, particularly here in Georgia, with the transmission system and our partners' participants in that process, GPC representing the EMCs. VA representing the municipalities.

That's evidenced by the performance of our system over the years from a reliability perspective as well as attracting economic development to this state. There is already, as we just talked about, a stakeholder process in the SERTP process that has gotten very little engagement.

Also, EIPC, which is the Eastern Interconnection Planning Collaborative, has a stakeholder process as well for providing stakeholder input into the planning process. So we do -- we do not feel it would be helpful. We feel it would actually slow down the planning process.

And the other issue is, 42 percent of the transmission owners in the state of Georgia are not party to this IRP.

Q All right. Thank you.

On page 44 of your rebuttal testimony, you state, "No other party conducted a renewable integration study or production cost simulation that identifies the reliability needs of the system in this case."

Which party do you contend should have performed such a study?

A (Witness Robinson) What's the reference again?

Q Page 44, line 12.

MADAM CHAIR PRIDEMORE: Line 12.

A (Witness Robinson) yes. Okay.

A (Witness Weathers) I don't think there's any contention about who should or shouldn't have done it, Mr. Baker. I think there was -- I think -- but it's also important to realize -- I mean, there were some criticisms about -- about these various studies, but just -- just a reminder that the company did a robust analysis.

The renewable integration study was a very detailed study of our system and how our system operates and is expected to integrate future additions of solar generation on our system.

That doesn't come without a cost. So the purpose was to identify that cost, identify appropriate ways to mitigate that cost, including either relying on the system as it is or adding battery storage which actually is a more efficient way to address those costs.

So the company did a robust analysis. The company is the only party in this IRP that did that analysis, so I think it's just -- it's just to give weight to the work and to the analysis that we did as being very informative to this proceeding.

BY MR. BAKER:

Q Thank you. Do the intervening parties have an obligation to correct the flaws in the company's modeling, or is it sufficient to identify the analysis --

the analysis contains flaws?

A (Witness Grubb) Well, I wouldn't call them flaws. There are different ways to model many different aspects, and so again, I think our point here is, this -- this proceeding is absolutely available for others to opine and evaluate our studies and our models.

But our point is that we've done a robust analysis, as Mr. Weathers said. No one else ran models to base that critique upon. So it's a -- it's again -- it's the -- it's the point that we did a thorough analysis.

Sure, anybody can -- that's what these hearings are for and what this proceeding is for, so people to -- to render judgment on those. But again, it's bolstered if their arguments are also backed up by their own analysis. We're just pointing that out.

Q But to conduct an analysis, similar to what the company did, the thoroughness and the comprehensiveness, isn't that an expensive and protracted process?

A (Witness Grubb) It is on our part, in terms of the amount of effort we put into it. Again, that's our -- that's our responsibility, and that's what we do. Again, we're just noting that, you know, critiques of our study were based on observing what we did but not running their own analysis. That's the point of that part of the testimony.

Q At page 50, regarding the process of developing RFPs, you say, "The decision not to adopt a developer's suggestion is made only after the suggestion has been fully vetted with the IE and the Commission staff, who either agree with the company's position to reject the developer's suggestion or note their disagreement at the time the RFP is submitted to the Commission for approval."

That seems to imply that if the Commission staff is silent on a topic, the company interprets that silence as agreement with the company's position to reject the suggestion.

Is that a correct interpretation?

A (Witness Mallard) I don't think so, and that's -- that's not really the way the process works, Mr. Baker. As part of the evaluation of the IRP, the company works very closely with the designated members of Commission staff and the independent evaluator.

When questions come in like this, they are thoroughly reviewed by each of those groups. Then a follow-up discussion, particularly when there is disagreement or when questions are complicated.

So to insinuate that there is some sort of silence indicates that, you know, staff just let something go, that's -- in my experience, that's not the way it happens. Each party is completely engaged in answering all of the questions.

Q Thank you. When SACE suggested addressing the eligibility gap in the capacity RFP, did the PSC staff explicitly agree with the company's position, or were they silent on it, or did they note their disagreement?

A (Witness Grubb) You said the capacity RFP?

Q Yes, sir.

A (Witness Grubb) And which provision of that?

Q Regarding position on the eligibility gap.

A (Witness Grubb) In terms of size of facility?

Q Yes, sir.

A (Witness Grubb) Yes. So I can't remember. That was two years or so ago, and I don't want to speak to staff. But, again, our position on 100 megawatts as the minimum size there, unless they were combined facilities, was really around the fact that we knew we were looking at coal retirements in the several thousand megawatt range. And you really want a system that's got some size to those facilities and also, you know, the number of bids.

So I can't recall the discussion with staff. I know we did discuss it. But the fact that we ended up moving forward with that 100-megawatt minimum size, had they disagreed with it, we would have -- we would still be discussing it, I guess. But -- so we eventually did move to a point of approval.

Q Thank you.

A (Witness Grubb) Um-hum.

Q Before any further expansion of the monthly netting program is considered, all 5,000 systems must be installed and the company must collect at least one year of data from all 5,000 customers participating to complete its analysis of the program impacts.

I believe you mentioned earlier, there was testimony, that right now there is approximately 4,200 customers that are installed?

A (Witness Grubb) That's right.

Q When will all 5,000 customers be installed?

A (Witness Mallard) So it's impossible to predict. We are down to the point now where there is a couple hundred more that are coming on line pretty quickly, but there is some projects that are not moving forward right now and we have to go project by project and find out if that project is still viable or not. If it's not, move them out and go to the next person on the waiting list.

So we are doing that just as quickly as we can. I would expect that we would have that done within the next couple of months.

That said, we are certainly not waiting until we get all 5,000 on line to start the analysis. The analysis is ongoing. We continue to evaluate those cost shifts, again both from the energy pushback from the grid and also from the energy that's consumed on site.

MADAM CHAIR PRIDEMORE: And, Mr. Mallard, you have failed to mention in this that a big component of it is that these are exterior companies that are doing the installations. You are waiting on other people within this supply chain to be able to get these stored.

So there is no supposition that the company is sitting on its hands, not doing anything and you only have 42 in the program. There is -- there is firm parties that you are waiting on, that they have to do their work before you can ever move forward and do yours. Correct?

WITNESS MALLARD: Thank you so much. Absolutely. Thank you for clarifying. There is a number of reasons why these projects are delayed. Some of them, completely legitimate: Supply chain issues. Getting, you know, proper approvals from the right authorities to do the installations. There is a lot of reasons.

But, no, we are actively working these projects just as quickly as we can. We continue to see a really high volume of projects. We are still way over 400 projects a month, even though monthly netting has been full for a year or so. So the market continues to respond here in Georgia. There is a really active rooftop solar market right now in Georgia.

COMMISSIONER MCDONALD: Do you have a number on the waiting list?

WITNESS MALLARD: I don't have that, but I can get it to you, Commissioner. But there is really -- there's not really a waiting list now. We've got a few hundred on the waiting list that we'll go through and convert them over to monthly netting.

COMMISSIONER MCDONALD: You mentioned a waiting list a minute ago.

WITNESS MALLARD: I did. But now customers are just signing up for instantaneous netting. Customers understand that they are not going to get retail monthly netting. And the market continues to grow. So what that tells me is it's possible to grow the rooftop solar market here in Georgia without monthly netting.

BY MR. BAKER:

Q But are you going to need -- at what point -- how many customers do you need to have so that you can get your year's worth of data to complete your evaluation? Is there a magic -- is 5,000 the magic number? What about 4,000? You have got 4,200. Isn't that a sufficient sample to give you an accurate assessment of what the impact is going to be and not wait until you have 5,000?

Q (Witness Mallard) Sure. So you can get a statistically valid sample -- and I'm not the right person to comment on what that would look like. But with less than 5,000 customers, absolutely.

That said, even with the 4,200, we would still need 12 months' worth of data. Just a few months' worth of data is not going to tell the whole story. So we need a subset of customers. We need 12 months of data. And as I mentioned, once we have 12 months of data and more, we are already starting that analysis and that's underway.

Q Well, wasn't your testimony earlier that you based your conclusion that there was cost shifting going on on basically a small group or a handful of customers? I mean, it doesn't sound like it was 4,200 folks.

A (Witness Mallard) That's right.

Q So, I mean, we are talking literally a dozen folks that you are basing this on, or what was the sample size that you based that conclusion on that there was cost shifting?

A (Witness Mallard) So those are two different things, so let's don't get those confused. What we are talking about is anecdotal evidence that shows that costs are shifted when a customer consumes solar on site. On an energy-only rate there, we absolutely lose more revenue than we save cost. That customer gets -- doesn't pay their fair share for use of the grid when the sun is not shining. So that absolutely happens.

But what we do need to get a really accurate estimate of the total impact of the 5,000 customer monthly netting pilot is a significant number of those customers that we have a year of data. And then obviously the most accurate will be once we do have a full year of data for all 5,000 of the exact customers.

What we are seeing is the size of these systems is growing because of monthly netting. What used to be an average residential system size of 3 or 4 kilowatts is now up to 7 kW or more. And so the program is changing. And so for those reasons, that we would want to get all 5,000 customers' data to get the overall full impact of the program.

A (Witness Robinson) And to expand on

Mr. Wilson's discussion on cost shift, regardless of size of customer, behind the meter solar, when that sun is not shining in the late evening hours, a thunderstorm comes over, that customer has got to be served reliably. And there is infrastructure associated with that service.

There is transformers, wires, poles, a substation, transmission lines connecting the generation of those megawatts that that consumer consumes during that period of time.

And when they are not paying for that, that cost is socialized to the other customers. And that's the issue.

Q And I hear you. But you're also describing it as anecdotal evidence in a very limited sample, is what you're basing that conclusion on.

MADAM CHAIR PRIDEMORE: As a commissioner, I disagree. That's a policy call. That's the whole structure of monthly netting. Monthly netting is exactly as Mr. Robinson just described. It's when that customer is not paying their fair share, then the cost to serve that customer and to offload energy from that customer are then socialized across the rest of the rate base, driving upward pressure on rates.

MR. BAKER: I'm not disagreeing with you on the

policy issue. I'm just saying, what did they base their -- this -- their conclusion on that there was cost shifting going on. And they said it's anecdotal evidence based on a very limited sample.

Now they're saying we need 5,000 customers who are installed, and we need one year's data from all 5,000.

MADAM CHAIR PRIDEMORE: Well, Mr. Baker, you and I must be listening to a different panel because I just heard this panel say that they don't have to get to all 5,000.

MR. BAKER: Well, I just heard -- let me get the clari- --

BY MR. BAKER:

Q Mr. Mallard, I heard you say all 5,000 just your last answer. Can't you start -- can't you start collecting -- don't you have a year's worth of data from 3,000 or 4,000 --

A (Witness Mallard) Absolutely.

Q You've got 3,000 customers --

A (Witness Mallard) And we're analyzing that now, Mr. Baker.

Q Okay. So could we get a -- is it possible to get a final report based on the 3,000 customers that you have a year's worth of date within, you know, the next

few months or so?

A (Witness Mallard) I mean, we're -- we're constantly doing that evaluation. We'll share that information with staff and commissioners as it's appropriate.

But back to the 5,000 customers. To get the full impact of the 5,000 customer monthly netting pilot will require all 5,000 customers to be online.

But to Chair Pridemore's point, we absolutely can identify cost shifts in a smaller sample size, and we have done that. Beyond that, Georgia Power's not the only utility that's done monthly netting. There's studies from lots of other states that show that that cost shift does exist when customers on energy-only rates install customer behind the meter generations.

A (Witness Robinson) And as a power delivery expert, I only need one customer to determine that there's a cost shift.

Q Not to belabor the point, but if --

MADAM CHAIR PRIDEMORE: But you're doing it anyway.

BY MR. BAKER:

Q No, no. 5,000, is that the miracle number? What if it's -- we've heard testimony that there are other installers that are in the process and this

Commission is trying to make a decision whether to continue this program because there's obviously demand for it out there. I mean, but if -- if you get -- are you going to wait -- if you hypothetically only have 4,999 customers installed and you're going to wait for that -- that magic five-thousandth customer before you get the full year's worth of --

A (Witness Mallard) Absolutely not. And if my testimony has led you to believe that, then I'm sorry that I misled you.

MR. HEWITSON: And just for the record, can I remind Mr. Baker that the 5,000 number was something that was directed by the Commission. And what Mr. Mallard, I believe, is trying to say is, if you're going to get the full impact of the pilot of 5,000 monthly net metering, then you've got to have all 5,000.

But what he's also saying is they can provide analysis and -- once they have customers signed on for an entire year. And as Mr. Robinson just said, he doesn't need all that, he can tell you right now about a cost shift because those customers that are on monthly net metering are not covering all their costs. I think that's been asked and answered several times now.

MADAM CHAIR PRIDEMORE: You are correct, Mr. Hewitson. Sustained.

COMMISSIONER MCDONALD: Except for one thing.

MADAM CHAIR PRIDEMORE: No, there's no exception to that.

COMMISSIONER MCDONALD: You said this was the policy of the Commission.

MR. HEWITSON: I said it was directed by -- the number was directed by the Commission.

MADAM CHAIR PRIDEMORE: Yes, it was.

COMMISSIONER MCDONALD: By the Commission, not all of them.

MADAM CHAIR PRIDEMORE: But it was still a -- it was a majority vote of the Commission, Commissioner.

COMMISSIONER MCDONALD: I understand.

MADAM CHAIR PRIDEMORE: The Commission instructed Georgia Power to do the program as a pilot with the cap.

COMMISSIONER MCDONALD: You made your point, and I made mine. Thank you.

MR. BAKER: Thank you, Commissioners.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Baker. You have a good day.

MR. BAKER: Thank you, panel. You have been very helpful.

MADAM CHAIR PRIDEMORE: Southern Renewable Energy Association.

If you go down this road, Mr. Mahan, you and I are going to have a challenge.

MR. MAHAN: Which road is that, ma'am?

MADAM CHAIR PRIDEMORE: Says the intervenor who has not been paying attention evidently.

COMMISSIONER SHAW: The road most traveled.

MR. MAHAN: I will not be talking about cost shifts or anything that Mr. Baker just --

MADAM CHAIR PRIDEMORE: Especially considering this isn't a rate case, but --

MR. MAHAN: Oh.

MADAM CHAIR PRIDEMORE: -- belabor my point.

MR. MAHAN: Gotcha. Yes, ma'am. No, I will not be doing that.

Good afternoon, panel.

PANEL: Good afternoon.

MR. MAHAN: Good afternoon, Commission.

CROSS-EXAMINATION

BY MR. MAHAN:

Q I'm Simon Mahan with the Southern Renewable Energy Association.

Just a few clarifying questions to begin off.

If the IRP and stipulation are approved by the Commission, is the Commission also approving the ten-year transmission plan?

A (Witness Grubb) Yes. I believe that's one of the items in there, yes.

Q Okay.

A (Witness Robinson) That is explicitly in?

A (Witness Grubb) That is correct.

Q I just wanted to check. Thank you.

Will the Southeastern Energy Exchange -- you're familiar with the Southeastern Energy Exchange Market?

A (Witness Grubb) SEEM?

Q Yeah, SEEM.

A (Witness Grubb) Yes.

A (Witness Weathers) Yes.

Q Will that be included in the 2025 integrated resource plan?

A (Witness Grubb) So when you say "included," I mean --

Q Modeled?

A (Witness Grubb) So I don't believe so. I'll let Mr. Weathers speak to that. We've filed a letter here. I'll let Mr. Weathers speak to that.

A (Witness Weathers) Yes. I mean, primarily that the resource plan is a -- is a capacity plan, and so the

SEEM market won't provide any new capacity for the company.

So that -- that is an energy-only product that's exchanged on a 15-minute basis. But to the extent in the future there's energy transactions that occur from that that we're able to predict on an occurring basis, we can model those in our -- in our pool modeling.

But from a capacity standpoint, it won't affect the capacity needs or capacity of the plant at all.

Q And so because it doesn't provide capacity, you can't say that the Southeastern Energy Exchange Market will improve reliability; correct?

A (Witness Grubb) In terms of capacity planning reliability, it may not. It is going to allow for --

Q Energy exchanges?

A (Witness Grubb) -- non-firm transmission of exchange, so there could be some benefits from not having to curtail some units. But, yeah, from a reliability standpoint, we're still going to plan to our specific utilities and to our specific pools.

A (Witness Weathers) Right. Yeah, we expect the benefits to be economic.

A (Witness Grubb) Yeah.

Q Sure. And will the Southeastern Energy Exchange Market cause the transmission system to be upgraded?

A (Witness Grubb) No.

A (Witness Robinson) I agree.

Q Let's move on to Stipulation No. 8 regarding the selected supporting information section of the Technical Appendix Volume I.

A (Witness Grubb) Okay. Item 8, transmission projects listed there.

Q That's right. That's the -- can we please call it the transmission retirement projects page --

A (Witness Grubb) Sure, absolutely.

Q -- because it's a mouthful?

A (Witness Grubb) I like that. Let's go with that.

Q And on that document, it contains -- does that document contain all of the transmission upgrades necessary to retire Wansley 1 and 2, Bowen 1 and 2, and Scherer 1 through 4?

A (Witness Robinson) Repeat that again. Wansley 1 through --

Q Wansley 1 and 2, Bowen 1 and 3, and Scherer 1 through 4.

A (Witness Robinson) That's -- 1 through 3 -- correct. The Scherer 4 is already decommissioned.

Q Okay. So that -- that assessment, the

transmission retirement project page, it found one transmission project associated with retiring Bowen Units 1 and 2. The LaGrange to north -- and forgive me, I'm not --

A (Witness Grubb) Opelika.

Q -- from -- I'm not from Alabama, so -- Opelika.

A (Witness Grubb) Right.

Q Appreciate it.

A (Witness Grubb) There's enough Auburn people up here to make sure you say it right.

Q Well, forgive me for that.

A (Witness Grubb) We all have our cross to bear.

Q That's the one line associated with Bowen 1 and 2 retirement; correct?

A (Witness Robinson) Directly, correct.

A (Witness Grubb) So it's important, Mr. Robinson, directly. So we sequenced Wansley 1 and 2 and Bowen 1 and 2. So that's additional for Bowen. The others support the retirement of Bowen.

A (Witness Robinson) Right. So you can't just take Bowen 1 and 2 out of this study, have it stand up by itself, be that project only supports that decision.

Q Okay. So the other projects ahead of that that have Wansley 1 and 2 next to it, those projects are needed regardless because of the Wansley 1 and 2 retirements?

A (Witness Robinson) Correct.

Q Okay.

MADAM CHAIR PRIDEMORE: Mr. Robinson, will you clarify, though, your previous answer? It's Scherer 3 only, not Scherer 1 through 3; correct?

WITNESS GRUBB: It's all three.

WITNESS ROBINSON: It was Scherer 1 through 3.

MADAM CHAIR PRIDEMORE: It is all three.

WITNESS GRUBB: We're not seeking retirement of 1 and 2 --

MADAM CHAIR PRIDEMORE: Right.

WITNESS GRUBB: -- but we are identifying the transmission projects to allow for the retirement of those.

MADAM CHAIR PRIDEMORE: Okay.

WITNESS ROBINSON: Right. Because it was voluntary, that decision could change. We need to have the transmission projects in place for that compliance date.

MADAM CHAIR PRIDEMORE: Okay.

BY MR. MAHAN:

Q Now, that -- the LaGrange to North Opeloka --

A (Witness Grubb) Opelika.

Q Opelika.

A (Witness Grubb) You like it. Just remember you really like it.

Q I like it. It's hard for me to like Alabama, sir.

That project crosses the Alabama state line; right?

A (Witness Robinson) That is correct.

Q Does the Alabama Public Service Commission need to approve that line?

A (Witness Robinson) Not explicitly.

Q Why not?

A (Witness Robinson) Because there is a mechanism at FERC where Alabama can charge Georgia Power for that --

COMMISSIONER MCDONALD: I can't hear you.

WITNESS ROBINSON: I'm sorry. There is a mechanism that's found at FERC where Alabama, if they don't see a need for that line, can charge Georgia Power through an affiliate transaction, so it's a transmission facility allocation cost tariff.

BY MR. MAHAN:

Q Okay. Now, that project isn't in North Georgia, though; right?

A (Witness Robinson) No, it is not. It is middle Georgia, as we would call it.

Q Closer to Columbus?

A (Witness Robinson) Correct.

Q It's actually closer to Stewart County than it is to Plant Bowen, isn't it?

A (Witness Grubb) I don't know. Stewart County is way down there with --

A (Witness Robinson) I don't know. I would have to look at a map.

A (Witness Grubb) I don't know.

Q Maybe?

A (Witness Robinson) Maybe. Subject to check.

Q That's fine. If the Commission delays the decommissioning of Bowen 1 and 2 to 2035, just to be sure, the company is still going to go ahead with that transmission project?

A (Witness Robinson) That's the plan; correct.

Q Okay. Now, on this list, still on the transmission retirement projects list, not all of the projects are owned by Georgia Power Company. How --

A (Witness Robinson) Yes, that is correct.

Q How is cost allocation determined between non-Georgia Power Company facility owners and Georgia Power? Is that through the FERC mechanism that you described?

A (Witness Robinson) No. That is through the

integrated transmission system here in Georgia.
Q So is it on a project-by-project basis then?
A (Witness Robinson) No. It's based on a parity calculation that's done on an annual basis.
Q And is that calculation reviewed and approved by the Georgia Public Service Commission?
A (Witness Robinson) It is not.
Q Now, backing up just a little bit, Mr. Robinson --
A (Witness Robinson) But I would say the Commission is -- I would say the Commission is aware of the ITS and how we have the cost generally.
Q I believe, Mr. Robinson, you mentioned earlier the 6 gigawatts of solar by 2035. And generally, it's in the integrated resource plan.
How does that figure play into the transmission planning process?
A (Witness Robinson) Can you repeat your question?
Q Yeah. The 6 gigawatts of renewable energy by 2035, how does that number and that date play into transmission planning?
A (Witness Robinson) So if you look in the 10-year plan that's filed with the IRP, you won't find those megawatts. So those megawatts are 2,300 megawatts

that Mr. Wilson is anticipating in this IRP as well as additional up to 6,000 megawatts by 2035.

And what we're working with the ITS participants on is assuming that 6,000 megawatts, assuming that the EMCs and municipalities also have renewable goals, their customers have renewable goals, the potential retirement of Bowen 3 and 4 by that date, that is strategic road map re-using the developed transmission to facilitate the retirement of Bowen 3 and 4 and the continued development of solar up to that 6,000 megawatt number.

Q Okay. So that 6,000 megawatt number is just as important today for transmission planning as the RFP numbers that we've been talking about?

A (Witness Robinson) Well, the purpose of beginning that strategic process to identify that transmission that we will bring forward in future IRPs, that number is important for us to put a bogey out there so that we can plan beyond the 10-year horizon because, typically, that's all we've done, and we've come in three-year increments with the IRP.

We see a need to be more strategic looking beyond that period of time towards that 2035 date incorporating all of that into what we call the North Georgia Reliability and Resilience Action Plan.

Q Okay. And so you will definitively then be looking past 10 years, specifically to 2035; is that correct?

A (Witness Robinson) We will -- yes. We are using that as a planning horizon for us to develop transmission as we move forward to meet not only these needs that you talk about in this chart that we just talked about but also the potential retirement of 3 and 4 and additional renewables.

Q And so if that 6,000 or 6 gigawatt by 2035 number, if it was larger and sooner, that would change the transmission solutions that y'all are going to come out with; is that right?

A (Witness Robinson) Not necessarily. Because there is a timing aspect of transmission. It could drive other projects, but you can't just take that 6,000 and say the EMCs is now 3,000. SO we're talking 9,000 by 2035. You can't take that 9,000 and just say you're going to do it in five years and get the transmission to make that happen.

Q Sure. Let's move on to Stipulation No. 9. Requiring the company to file an annual transmission update report. In that stipulation -- I will let y'all take a moment here.

Do you take that stipulation to mean that all the transmission projects in the 10-year transmission plan, or is it just the 15 transmission projects identified in the transmission retirement project list?

A (Witness Robinson) Yes. It is only the projects associated with the selected supporting information contained in Volume 1, which is the table that we just referred to.

Q And so after the last transmission project on that list gets done, either canceled or built, you will no longer do an annual transmission update to the Commission?

A (Witness Robinson) Under this requirement, that's correct.

Q Okay. Stipulation No. 9 also requires that the company identify alternative solutions and the associated costs and benefits of the alternatives.

Do you have a list of all the types of alternatives for transmission that you plan to investigate?

A (Witness Robinson) There is a list in Volume 3 of alternatives that we anticipate and that we evaluate.

Q I forgot. Does that list include battery storage as a transmission alternative?

A (Witness Robinson) Let me get out Volume 3 and check.

A (Witness Grubb) That's a big volume, so it's a lot of stuff in there.

Q 401 pages.

A (Witness Grubb) There you go.

Q If you're having trouble finding it --

A (Witness Robinson) Yeah, I'm having trouble finding it.

But we did answer a data request where we expounded on that, and we did list battery storage as one of those alternatives.

Q Okay. Yeah. And so I was going to give you an out here saying that batteries could be a transmission alternative.

A (Witness Robinson) Okay. And we did evaluate battery storage in the -- between the 2019 IRP and 2019 rate case as ordered by the Commission, and I believe Mr. Chiles had referred to that and said that we did not provide that, but we did provide that.

We did a study in between those two proceedings and provided that information to staff and Mr. Chiles on the meeting that we had on September 10th of 2019.

Q Yeah. I recall that part in your testimony where it said you evaluated battery storage, but you rejected it because it wouldn't solve TPL 0001; is that right?

A (Witness Robinson) Well, it was -- the run time was an issue. So you've got to have batteries for the length of the contingency you're anticipating. So if it's 500 KB line, 500 KB line can be out for days.

And so you would need to solve that overloaded strength for that period of time. And I believe we looked at -- subject to check -- it was a four-hour battery for an $80 million transmission project. The cost of such battery to resolve that was in the one-and-a-half billion range.

Q Right. Okay.

So in that one situation, batteries weren't a good solution?

A (Witness Robinson) Correct.

Q Regarding the benefits of the transmission alternative, so we're still regarding the Stipulation No. 9 where you're supposed to look at all the costs and the benefits of the transmission alternatives.

Do you have a list of all the types of benefits, transmission benefits to be considered?

A (Witness Robinson) There are benefits that are listed in Volume 3 as well.

Q Is that on page 23 of Appendix A?

A (Witness Robinson) A little hard to do when you are sitting in the chair. Which reference again?

Q I believe it's page 23 of Volume III, Appendix A.

A (Witness Robinson) That's correct.

Q And that's it. Those are all the benefits that you've got?

A (Witness Robinson) No. There are -- there could be other benefits as well, but these are the main benefits we looked at as it relates to alternative projects.

Q All right. Regarding the -- the benefits and how you calculate the benefits, what's the time horizon that you calculate those benefits over? Is it 20 years? 40 years?

A (Witness Robinson) It depends on the life of the project. But if we were to do a revenue requirement evaluation that's listed in here, we would -- typically a traditional transmission solution would be evaluated at a time around 40 years. Battery system would be less, because a battery system does not have a 40-year life. So we would look at the life of a system, and do that calculation as it relates to net present value.

Q Okay. So you don't have a set time horizon for the benefits; it's based on whatever specific technology you're selecting?

A (Witness Robinson) Based on the life of the asset we're choosing; correct.

Q Okay. What if the company finds an alternative better than the projects listed in the transmission retirement projects list? How are those alternatives proposed and approved by this Commission?

A (Witness Robinson) Ultimately it would be through the rate case, ASR process, through the IRP process. But there is another approval process that those projects go through, and that's the integrated transmission system -- the planning process we have there. There are several working groups that go through an approval process and review. Those projects are well vetted, and ultimately a decision is made to put those into parity, and accept those into parity in the ITS.

Q The ITS outcomes aren't necessarily given back to the Commission for their review and approval?

A (Witness Robinson) They are through the ten-year plan.

Q And how often does the ten-year plan get approved by the Commission?

A (Witness Robinson) Every three years.

Q Okay.

MADAM CHAIR PRIDEMORE: I can already tell you -- this is going to be a lot easier. He has a renewable in his name, but this is all transmission. So if you want to go ahead and switch places with Wilson so you can get your books out, it might be easier on you, Mr. Robinson.

WITNESS ROBINSON: Yes, I agree with that. Thank you.

MADAM CHAIR PRIDEMORE: He has "renewable" in his name, but there's nothing about his questions that have anything to do with solar or renewable energy. This is 100 percent transmission.

MR. MAHAN: Which the renewable assets need.

MADAM CHAIR PRIDEMORE: Everything is transmission, Mr. Mahan.

MR. MAHAN: I agree.

MADAM CHAIR PRIDEMORE: I would be interested to know, who -- I would be interested to know the members of your association.

MR. MAHAN: I'd be happy to give those to you afterwards.

MADAM CHAIR PRIDEMORE: Great. Thank you.

MR. MAHAN: I don't even keep track of them that closely.

BY MR. MAHAN:

Q You mentioned on page 37 of your rebuttal that the company doesn't need additional Commission or

stakeholder oversight because you participate in SERTP?
A (Witness Robinson) Can you -- what are you referencing?
Q Page 37 of your rebuttal testimony. You say that "The company doesn't need additional Commission or stakeholder oversight because you participate in SERTP."
Who is in charge of SERTP?
A (Witness Robinson) The SERTP is governed by the 12 companies and 10 planning entities that participate in that process.
Q Does SERTP have a planning horizon further than ten years out?
A (Witness Robinson) Not at the moment.
Q So how are you going to be able to take a longer than ten-year planning horizon with the North Georgia reliability projects and insert them into SERTP if SERTP can't even accept them?
A (Witness Robinson) Well, I think there's ways you can talk beyond the horizon. I think the current NOPR that's out there that FERC let a couple weeks ago, it proposes to address that horizon issue.
Q How so?
A (Witness Robinson) They propose a 20-year horizon.
Q So you would -- you're recommending following

the FERC NOPR and doing a 20-year planning horizon for transmission?

A (Witness Robinson) I did not say that. I said the NOPR that has been let, it suggests a 20-year planning horizon.

But as far as SERTP, if we saw benefits beyond ten years, and there are projects that show benefits beyond ten years, we would definitely discuss those in that forum.

Q And you're familiar with the SERTP economic planning studies process?

A (Witness Robinson) Not intimately.

Q Okay. If you go to SERTP and you were to ask to study a 6 gigawatts -- a 6 gigawatt number of solar in South Georgia, do you know if SERTP is able to study that exact scenario?

A (Witness Robinson) That exact scenario is very difficult to study. There's a tremendous amount of assumptions that have to be made to study that amount of megawatts in South Georgia, as we're going through those studies right now with our ITS participants.

Q So you probably wouldn't be able to do that through SERTP?

A (Witness Robinson) Use the same planning principles. I think you have to make some assumptions on location of solar, where it's going to be in South Georgia. A lot of it right now is in Southwest Georgia, but I think you've got to make an assumption of where those megawatts are going to be so you can plan for the future.

Q You had mentioned earlier that SERTP allows for stakeholder participation. Are you aware that SERTP limits the economic planning studies to just five studies across the entire region?

A (Witness Robinson) I'm not aware, but since none of those have been brought, I'm not sure that's an issue.

Q And did you know that just because a stakeholder requests a study to be done, that doesn't mean SERTP has to conduct that study?

A (Witness Robinson) That's correct. They can propose a study, but they don't have to take that study up.

Q And did you know then in 2014 in the SERTP stakeholder process, the Southern Environmental Law Center requested studying evaluating Southern Company's coal retirements but that study was rejected by SERTP?

A (Witness Robinson) I'm not aware.

Q You see on page 41 on the top of your testimony, at the very top, that you're opposed to assessing an economic congestion of the transmission system in the locational value study.

Why can't you perform an economic congestion component?

A (Witness Robinson) We don't have models to do it.

Q Which models do you need to do it?

A (Witness Robinson) Security constraint dispatch for one, and the models that you develop in an RTO. We're not in an RTO. We do not have those models.

MADAM CHAIR PRIDEMORE: Speak in for me, Mr. Robinson. Thank you.

BY MR. MAHAN:

Q Have you considered asking those other regions to conduct the a study for you?

A (Witness Robinson) Which other regions?

Q The RTO regions.

A (Witness Robinson) No. We have no interest in that.

A (Witness Weathers) And, Mr. Mahan, as Mr. Robinson said, we're not an RTO, and we don't plan our system in order to have economic congestion on our system, so we -- we plan our system to not have that.

So we have -- we operate our system and plan it so that we -- that the generation can be delivered from the generation source to the customers without constraints. And so the suggestion here about locational value study by including economic congestion implies no low pricing. That's an RTO-type construct. That's just not the way our market operates.

A (Witness Robinson) Right. It anticipates us having an RTO. We are not an RTO. We don't design and plan our system that way.

MADAM CHAIR PRIDEMORE: When have you ever heard the word "congestion" used in a positive framework anyway? It's congestion.

WITNESS GRUBB: Only if you made money off of it, I would believe.

MADAM CHAIR PRIDEMORE: Well, there's plenty of people at RTOs that do, yes.

BY MR. MAHAN:

Q And so is it then your testimony that there is no congestion on the Georgia Power transmission system?

A (Witness Robinson) We -- we plan our system to be reliable to address constraints that are studied in our planning process, and we have a reliable system. That's what is in this ten-year plan. We do a lot on a real-time basis to manage restraints on -- or constraints on our system on a real-time basis because of outages and changes on the system, but we plan our system to be reliable through the NERC planning process.

Q So, yes, there is no congestion problem anywhere in the Georgia transmission planning system?

A (Witness Robinson) We do not feel that there is any type of congestion. This system is very reliable.

Q But again, you've not studied it?

A (Witness Robinson) We're not an RTO.

Q Stipulation 10, please. "The company will work with the Commission staff to develop a process that facilitates the development of renewable resources in North Georgia."

Why isn't Georgia an attractive place for renewables to develop?

A (Witness Robinson) Why is it not?

Q Yes.

A (Witness Robinson) I would argue that it is.

A (Witness Mallard) Yeah, I would say that Georgia's an incredibly attractive place for renewables to develop. Top five last year.

Q All right. Don't you think it would be helpful to collaborate with renewable developers to figure out why they're not focused in on -- why they're not as bullish about North Georgia as you guys are?

A (Witness Mallard) So absolutely feedback from the market is critical to developing our RFPs in ways that the market can be successful in their response to us, and so we do that. We've talked about that a little bit already. We've got a lot of before, during, and after opportunities to communicate to the marketplace.

So what we have heard from the marketplace is what is relatively evident just by looking at the topography and geography of Georgia, and that is flatter land in South Georgia, there's a better solar resource. And so North Georgia, you're going to have to maybe work a little bit harder to find suitable sites.

Not to say that there's not going to be suitable sites, but they may be a little bit more difficult to identify and develop.

Q And so you understand --

COMMISSIONER MCDONALD: Developers are going to have to work harder, not North George. I mean --

WITNESS MALLARD: The developers will have to -- they're the ones that are out -- right now -- my assumption, Commissioner, is that once we file this request for -- for North Georgia, that significant amounts of solar developers are seeking sites in North Georgia since that time.

WITNESS ROBINSON: And we understand that there are cost issues associated. This is not a cost issue. This is a timing issue. This is a timing

issue for us to get the transmission built so that we can continue to develop in South Georgia. That's where -- we see benefits to that as well.

And there are also, as I mentioned before, regional benefits to having renewables in North Georgia. Particularly around geographic diversity, and that's been evidenced over the last week where we've had sunny days up here and rainy days down south.

BY MR. MAHAN:

Q But isn't it more likely that projects in the northern part of the state are going to be smaller than 100 megawatts?

A (Witness Robinson) I can't say that. I know that where we've defined there are -- there are plenty of areas where there are large tracts of land, but I can't say that. I'm not a developer.

Q And so wouldn't it be helpful to get a developer's opinion about that?

A (Witness Grubb) So, again, we do absolutely depend on feedback from the development community, and that happens through our normal processes, both formal and informal communications, but all of which comply with the Commission's rules.

Q Let's move on to Stipulation No. 18 regarding

the next all-source capacity RFP for 2029 to 2031.

Is that RFP dependent on retiring Bowen 1 and 2?

A (Witness Grubb) It is not. The years may shift. We've got a lot of PPAs that roll out in 2030, about 2,000 megawatts' worth. So we would expect a need in '30 even if Bowen 1 or 2 or both are extended.

Q When do you anticipate this new all-source capacity RFP to come out?

A (Witness Grubb) So we'll work with staff on that. The first thing we'll do is we'll look at our updated -- well, first, is what comes out of this IRP. We'll update those resource decisions. Then we'll get a load forecast update this fall. And we'll then look at our needs chart and work with staff on when that need is and, obviously, the timing, also, is driven by which resources you want to allow time for.

Q Okay.

A (Witness Grubb) So I think staff's testimony pointed at around seven years, which is normal, if you want to allow for a new gas construction bid. So we'll work through all that with staff once we update our numbers this fall.

Q And how big will the RFP be?

A (Witness Grubb) So it'll depend, again, on what

the Commission's decision is there. But it could be anywhere from 500 to 1,500 megawatts. Just depends on what happens. We've got a lot of economic development customers looking at the state. If we land some of those as Georgia Power customers, that'll go into the load forecast.

So it'll -- it just depends on three or four different moving factors.

Q Yeah. So y'all are requesting that the Commission approve an RFP that may come out at some point for an unknown amount of megawatts?

A (Witness Grubb) Yeah. So typically, I think even back to the 2019 IRP, we just asked for a request to have an RFP. Those details will be worked through in the RFP process. So we would -- again, we would look over what the needs are and then when that RFP needs to go out and then work through the normal RFP procedure with the Commission and staff.

Q Okay. Stipulation 19. And I think I heard this panel mention earlier that any renewable project anywhere in the country could submit a bid into the renewable RFP. Did I hear that right?

A (Witness Mallard) That's right.

A (Witness Grubb) Which has always been the case; correct?

A (Witness Mallard) That's always been the case. There's a project in interconnect to Georgia Power to the ITS to the Southern Company Balancing Authority or anywhere in the United States and have the power wheeled to our balancing authority.

Q Okay. If a renewable energy project were to enter into the generation interconnection queue today, how long would it take for them to get their first study results back?

A (Witness Robinson) As far as system impact study?

Q Yes.

A (Witness Robinson) About 12 months.

Q So June --

A (Witness Robinson) 8 to 12 months.

Q June 2023. When's the 2023 renewable RFP supposed to come out?

A (Witness Mallard) So as it's scheduled right now, the RFP will come out sometime in 2023. Probably second to third quarter. Again, with CODs required by the end of '26 or the end of '27.

Q And if you issued a statewide RFP, Northern Projects, Northern Renewable Energy Projects could still bid into that RFP, though; right?

A (Witness Mallard) Yes. All projects would be --

A (Witness Grubb) We would hope they would.

Q Stipulation 29, page -- it's a big one. It's on page 8 of the stipulation, and it's towards the bottom of that stipulation.

A (Witness Grubb) So it's on page 8, bottom half of 29?

Q Yes.

A (Witness Grubb) Okay.

Q So both Stipulation 29 and Stipulation 30 both refer to adopting an effective load carrying capacity or an ELCC methodology.

Do you see those?

A (Witness Grubb) That's correct.

A (Witness Robinson) Yes.

Q Is it -- is the effective load carrying capacity that y'all are going to use, is it for all seasons, or is it just for the summer season?

A (Witness Weathers) No, It's for all seasons. I mean, you're evaluating it both for the winter and the summer seasons.

Q And the fall and the spring?

A (Witness Weathers) Yes. Yes. Generally, that -- it's captured in there. We're doing an annual study, and so we can separate the time periods, but it is -- it is -- it covers the entire annual period.

Q That's right. And is it for all resources or just renewable energy resources?

A (Witness Weathers) Well, it's for -- so the company has -- has always had an approach to produce capacity equivalency for energy limited or variable energy resources. So ener- -- you know, such as renewable resources, such as hydrogeneration, such as demand-side resources. So it would be applied across all resources.

Q Including any potential gas units?

A (Witness Weathers) Well, gas units are -- do have 100 percent, so they're -- they're dispatchable units. They don't have the -- they don't have the energy limited or variable energy aspects that renewable energy resources have.

Q So you assume gas units are 100 operational in your IRP models?

A (Witness Weathers) Well, so they had -- the capacity contribution is at 100 percent level. We do assume that they will have outages, and so that's taken into account in the model. But from just in terms of stating the capacity of the unit, we do assume that the 100 percent capacity level.

Q Okay. And so that's for all existing units as well?

A (Witness Grubb) If they -- if they don't have limitations, as Mr. Weathers mentioned. So example of a hydro facility may have a limited pool or something like that across 8 hours. So again, I think the point on the 100 percent reliability on the gas units is not that they are 100 percent always available.

It's just when you run those reliability models with a little bit of availability, they can meet more reliability needs than others. So you compare it. You kind of set that as unity and base everything off of that.

Q Okay. Stipulation 35. This -- this will be the last bit of questions I've got, regarding that Tall Wind demonstration project.

The turbines you describe in the work papers are only 4 megawatts. Are you aware that there are onshore wind turbines potentially in the 6 to 8 megawatt range now?

A (Witness Mallard) Generally aware, yes.

Q And are you aware that a larger wind generator can increase energy output?

A (Witness Mallard) Yes. Absolutely. The 3 to 4 megawatts that we teed up here in the Tall Wind demonstration project, that's based on overall project design, interacting with the new spiral well tower technology, and so that's really what the basis was for the project budget and the initial evaluation of the project.

Q Okay. And if Georgia Power were to select a generator larger than 4 megawatts, would the company need to come back to the Commission for approval?

A (Witness Mallard) Yes, absolutely. Now, the company will come back to the Commission for approval anyway of the overall project costs once we have identified the site, the EPC, have the final cost benefit done. But absolutely, if that range of megawatts were to change, that would need to be approved by the Commission as well.

MR. MAHAN: All right. That's it. I appreciate it.

WITNESS ROBINSON: Thank you.

WITNESS MALLARD: Thank you.

WITNESS GRUBB: Thank you.

MADAM CHAIR PRIDEMORE: Redirect?

MR. HEWITSON: Thank you, Madam Chair. Just a few questions.

REDIRECT EXAMINATION

BY MR. HEWITSON:

Q Mr. Grubb, you were asked some questions about the hydroelectric facilities just in general. And do investments in hydro facilities generally improve the efficiency of the hydro unit itself?

A (Witness Grubb) Yes, they do.

Q Okay. And do these efficiency improvements generally decrease future O&M expenses to those hydro facilities?

A (Witness Grubb) Yes, they do.

Q Are you aware of any structural issues with the dams themselves in the North Georgia hydro projects?

A (Witness Grubb) No, I do not. My understanding is they are all studied under our Dam Safety Program and are all very structurally sound and were recommended to be able to last for years to come.

A (Witness Mitchell) I would add, Commissioner McDonald, you asked a question about the Dam Safety Program and regulation in Georgia. While we do maintain a robust dam safety program at numerous facilities under the Georgia Safe Dams Program, hydroelectric facilities regulated by FERC are exempted from that.

However, FERC has their own set of dam safety requirements, in fact, more stringent, that we adhere to, and we do share that information with the state of Georgia Safe Dams Program.

COMMISSIONER MCDONALD: The Georgia soil and water conservation people, they have always been very involved in the dam safety side, if I understand it correctly.

WITNESS MITCHELL: Yes, sir, that's right.

BY MR. HEWITSON:

Q Well, since you have the microphone, Mr. Mitchell, Mr. Fabish asked you about ash ponds being closed in place that have CCR and contact with groundwater. So my question to you is, do the closure plans take that into consideration and address that issue?

A (Witness Mitchell) Yes, they do. And, Commissioners, we testified at length in the direct hearing about the work that the company has done to ensure that we are complying with the performance standards. What Mr. Fabish asked me about was one of several of those performance standards for a closure-in-place ash pond.

We talked at length about the plans that we've put together and submitted to Georgia EPD; and, in fact, staff through one data request asked us about some information. We submitted some of that information to the Commission in this IRP, in total of 15,000 pages.

That represents just a fraction of what we have

submitted to Georgia EPD to illustrate the robust engineering designs and compliance plans that we have put together to comply with exactly the performance standards that was asked about earlier.

Q And those plans are specific to each and every site, in fact, each and every ash pond; right?

A (Witness Mitchell) Very site specific; and in fact, even in the new interpretations that EPA announced in January, and in several publications thereafter, where EPA addresses performance standards.

They acknowledge that site specificity is important in determining compliance. And, also, the engineering measures that each site and each ash pond has incorporated into its design is very important in determining compliance for the federal and, here in Georgia, the state CCR rule.

MR. HEWITSON: Thank you, gentlemen. That's all I have for you this afternoon.

Madam Chair, I would ask that all of Georgia Power's exhibits in the IRP be moved into evidence. I believe that's 1 through 20.

MADAM CHAIR PRIDEMORE: So moved.

(GPC Ex. 1 - 20 were admitted into evidence.)

MADAM CHAIR PRIDEMORE: Thank you very much, gentlemen. You are excused. We're going to take a

10-minute break. We will come back at 3:05 for the

(A recess was taken.)

MADAM CHAIR PRIDEMORE: All right. Ms. Pryor, swear in your witnesses, please.

MS. PRYOR: Thank you.

Good afternoon, Commissioners. Allison Pryor for Georgia Power Company. At this time I'd like to call Georgia Power Company's next panel of witnesses on rebuttal: Mr. Valle, Mr. Phillips, Mr. Smith and Mr. Evans.

Gentlemen, please raise your right hand.

Thereupon,

FRANCISCO VALLE,
ANDY PHILLIPS,
JEFFREY K. SMITH,
LEE EVANS,

having been duly sworn, testified as follows:

MS. PRYOR: Each of you have previously testified in this proceeding; correct?

THE PANEL: Yes.

DIRECT EXAMINATION

BY MS. PRYOR:

Q Mr. Valle, would you once again please state your full name, your employer, and your title for the record.

A (Witness Valle) Francisco Valle, director of market planning for Georgia Power, and my responsibilities are load forecasting and economic analysis.

Q And Mr. Phillips?

A (Witness Phillips) Andy Phillips, I manage the profitability and economic analysis chain for Georgia Power Company, and I'm located at 241 Ralph McGill Boulevard, Atlanta, Georgia.

Q And Mr. Smith?

A (Witness Smith) Jeffrey K. Smith, Georgia Power energy efficiency strategy manager.

Q Mr. Evans?

A (Witness Evans) Lee Evans, director of demand planning and analysis where I support the operating companies with planning and economic analysis.

Q Thank you.

Mr. Valle, on June 8 of this year, did you prefile or caused to be prefiled 34 pages of rebuttal testimony in question-and-answer format in this docket?

A (Witness Valle) Yes.

Q Are there any corrections you need to make to your prefiled testimony?

A (Witness Valle) No corrections.

Q If I were to ask you the same questions today under oath, would your answers be the same as are set forth in your prefiled testimony?

A (Witness Valle) Yes.

Q Thank you.

Mr. Valle, on June 8th of this year, did you prefile or cause to be prefiled 34 pages of rebuttal testimony in question-and-answer format in this docket?

A (Witness Valle) Yes.

Q Are there any corrections you need to make to your prefiled testimony?

A (Witness Valle) No corrections.

Q If I were to ask you the same questions today under oath, would your answers be the same as are set forth in your prefiled testimony?

A (Witness Valle) Yes.

MS. PRYOR: The court reporter has been provided a copy of the prefiled rebuttal testimony. I now ask the rebuttal testimony of this panel be copied into the record as if given here today.

MADAM CHAIR PRIDEMORE: Yes, so moved.

(Whereupon, the prefiled direct testimonies of Mr. Valle, Mr. Phillips, Mr. Smith, Mr. Evans follows:)

STATE OF GEORGIA

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:

Georgia Power Company's	**)**	**Docket No. 44160**
2022 Integrated Resource Plan	**)**	

Georgia Power Company's	**)**	
2022 Application for the Certification,	**)**	**Docket No. 44161**
Decertification and Amended	**)**	
Demand-Side Management Plan	**)**	

REBUTTAL TESTIMONY OF
FRANCISCO VALLE, ANDY PHILLIPS, JEFF SMITH,
AND LEE EVANS

June 8, 2022

REBUTTAL TESTIMONY OF
FRANCISCO VALLE, ANDY PHILLIPS, JEFF SMITH,
AND LEE EVANS

IN SUPPORT OF GEORGIA POWER COMPANY'S

2022 INTEGRATED RESOURCE PLAN

GPSC DOCKET NO. 44160

AND

APPLICATION FOR THE CERTIFICATION, DECERTIFICATION AND AMENDED DEMAND-SIDE MANAGEMENT PLAN

GPSC DOCKET NO. 44161

I. INTRODUCTION

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

A. My name is Francisco Valle. I am the Director of Market Planning for Georgia Power Company ("Georgia Power" or the "Company"). My business address is 241 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308.

A. My name is Andy Phillips. I am the Profitability and Economic Analysis Manager for Georgia Power. My business address is 241 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308.

A. My name is Jeff Smith. I am the Manager of Energy Efficiency Strategy for Georgia Power. My business address is 241 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308.

A. My name is Lee Evans. I am the Director of Demand Planning & Analysis for Southern Company Services, Inc. ("SCS"). My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

Q. DID YOU PREVIOUSLY PRESENT DIRECT TESTIMONY ON BEHALF OF GEORGIA POWER IN THESE PROCEEDINGS?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of our testimony is to respond to the testimony of the Georgia Public Service Commission ("Commission") Public Interest Advocacy Staff ("Staff") and various intervenors filed in Docket Nos. 44160 and 44161. Due to the number of Parties filing testimony in this case and the limited time available to file rebuttal, our testimony focuses on several key issues without attempting to address every issue raised in Staff or intervenor testimony. However, the fact that the Company may not respond to a particular position of Staff or an intervenor should not be construed as acceptance of such position.

Q. PLEASE SUMMARIZE THE TESTIMONY OF THE PANEL.

A. The Company's Budget 2022 Load and Energy Forecast ("Budget 2022") appropriately provides a twenty-year forecast of energy sales and peak demand to meet the planning needs of Georgia Power. Although Staff and several intervenors offer suggestions for potential changes in the next IRP, no party proposes any changes to the Company's Budget 2022 Forecast. As approved in the 2019 IRP, the Company continues to support the use of an all-years weather normal definition, which provides a more stable weather definition than using a 20-year rolling average, while still capturing warming trends in the weather. In addition, Georgia Power does not support continuing to update the residential saturation survey because it is an expensive undertaking. Instead, the Company supports the use of the Energy Information Administration's ("EIA") end use data for the South

Atlantic, as it is developed with a larger data set based on regional data that is updated regularly and is both publicly available and free to access.

The Company's proposed DSM plan is in the best interests of customers because it appropriately maximizes economic efficiency and minimizes upward pressure on rates in accordance with the Commission's current DSM policy. As in prior IRPs, Georgia Power integrates DSM into its resource planning process and treats energy efficiency as a priority resource. Before the development of the supply-side plan, the first step in the Company's planning process is to reduce the peak demand and energy forecast by the amount of the DSM programs. Contrary to Staff and intervenor testimony recommending increased savings targets, it is appropriate to use savings targets consistent with those approved in the 2019 IRP for the 2023-2025 cycle given that increased savings targets require higher budgets and increase upward pressure on customer rates. For example, in year three of the program cycle, when the Advocacy Case reaches its proposed long-term savings targets, the Advocacy Case increases the cost of the DSM programs by 350% relative to year three of the Company's Proposed Case.

All parties agree that an additional sum for the Company's DSM programs is appropriate. However, to appropriately incentivize the Company to offer DSM programs, the additional sum must be a non-zero amount. The Company's proposed additional sum methodology would provide an adequate incentive for implementing residential and commercial DSM programs based on and consistent with the amount of kWh savings achieved. Compared to the current methodology, the Company's proposed additional sum methodology is simpler, more stable, better aligns the additional sum with the energy savings achieved from the customer classes eligible to participate, and creates an opportunity for the Company to earn an additional sum similar in value to that intended when the Company began offering DSM in 2010.

Finally, the Commission should approve the DER Customer Program as proposed by Georgia Power. The DER Customer Program leverages distributed energy resources ("DER") to strengthen grid reliability for all customers, creates a more flexible and diverse resource mix, promotes cleaner DER resources, and increases resilience for Georgia Power's participating customers. The DER Customer Program will provide demand response value and corresponding System resilience and reliability benefits for all customers, and support commercial and industrial customers with enhanced resiliency needs.

II. LOAD AND ENERGY FORECASTS

Q. HOW DOES THE COMPANY CURRENTLY DEFINE WEATHER IN ITS LOAD FORECAST?

A. The Company currently defines weather in its load forecast, also referred to as "normal weather," as a 41-year average of Heating Degree Hours ("HDH") and Cooling Degree Hours ("CDH") on a monthly basis between 1980 and 2021. HDH represents temperatures below a certain threshold mainly in winter and CDH represents temperatures above a certain threshold mainly in summer. As new data years become available, the Company plans to add to the total number of years used to calculate the normal weather to be used in consecutive forecasts.

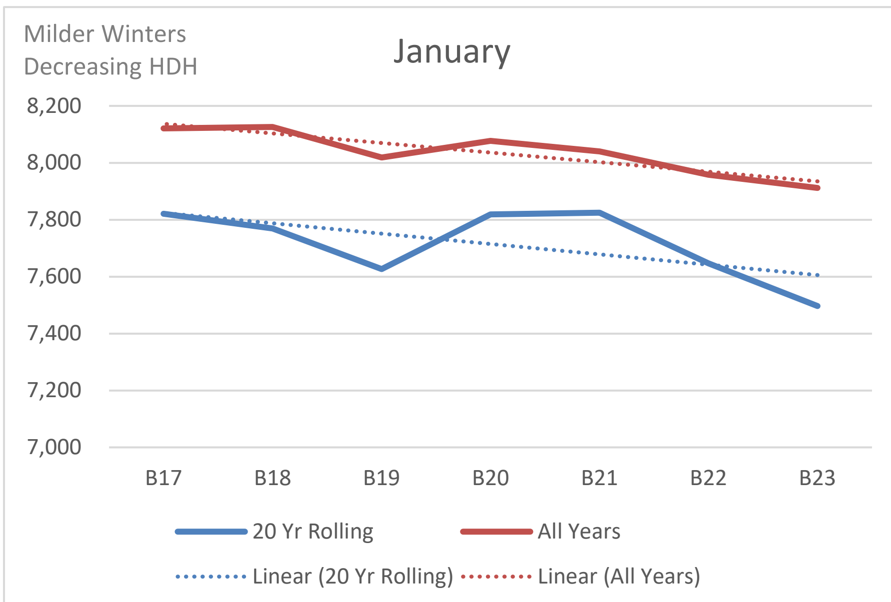
Q. WHY DOES STAFF WITNESS THOMAS ARGUE THAT THE COMPANY SHOULD USE A ROLLING 20-YEAR AVERAGE FOR WEATHER IN THE FORECAST?

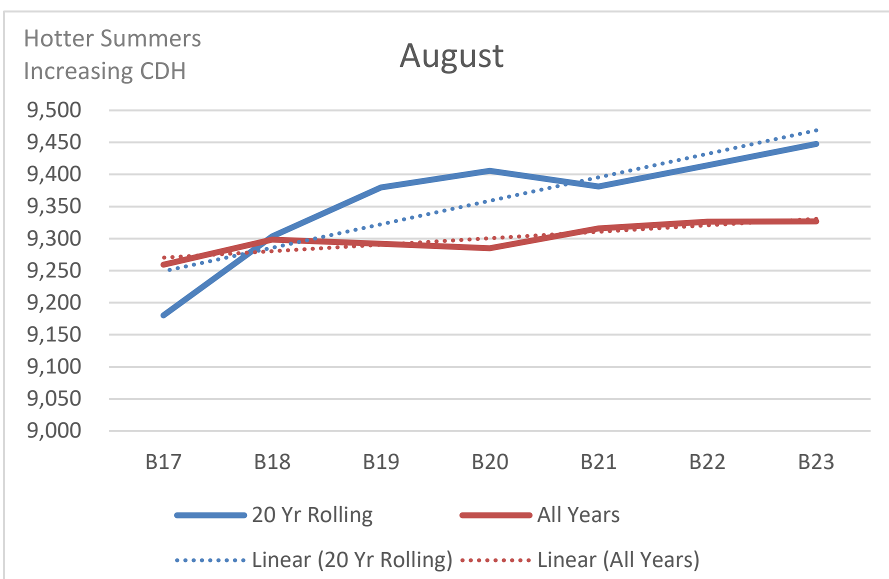
A. Staff Witness Thomas argues that a 20-year average would better capture warming trends in temperatures because the average would represent the most recent 20 years. (Tr. 693.)

Q. DOES AN ALL-WEATHER AVERAGE STILL CAPTURE WEATHER TRENDS?

A. Yes. The definition the Company used shows the same trends over time as the 20-year average; however, the magnitude of the trend is less pronounced when compared to a 20-year average.

FIGURE 1: 20-YEAR VS. ALL YEARS TRENDS



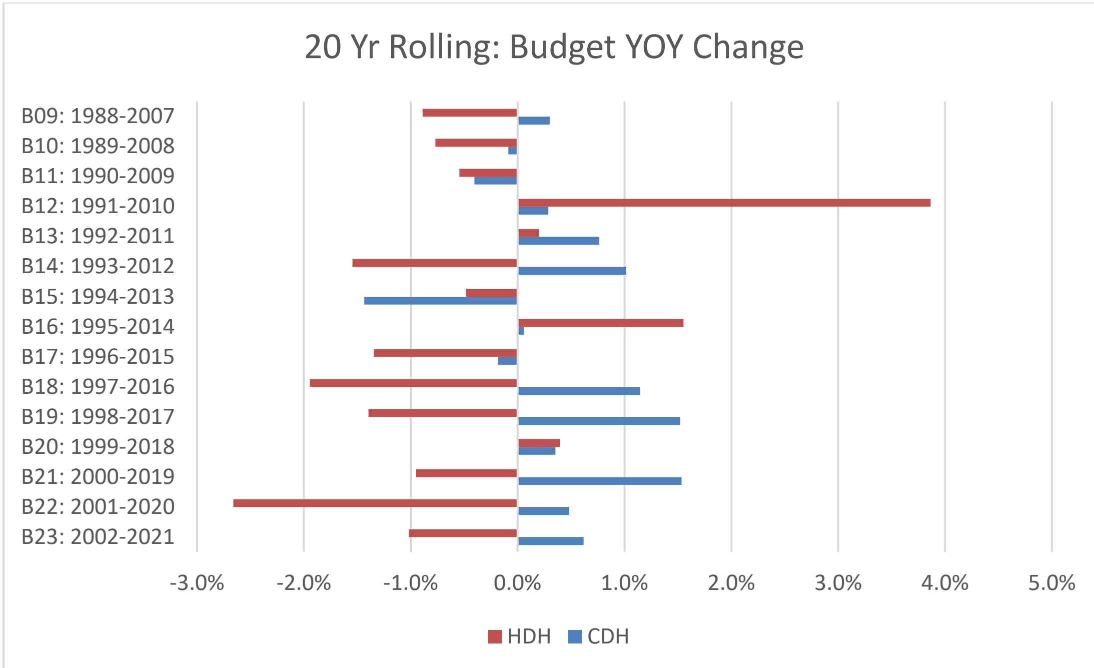


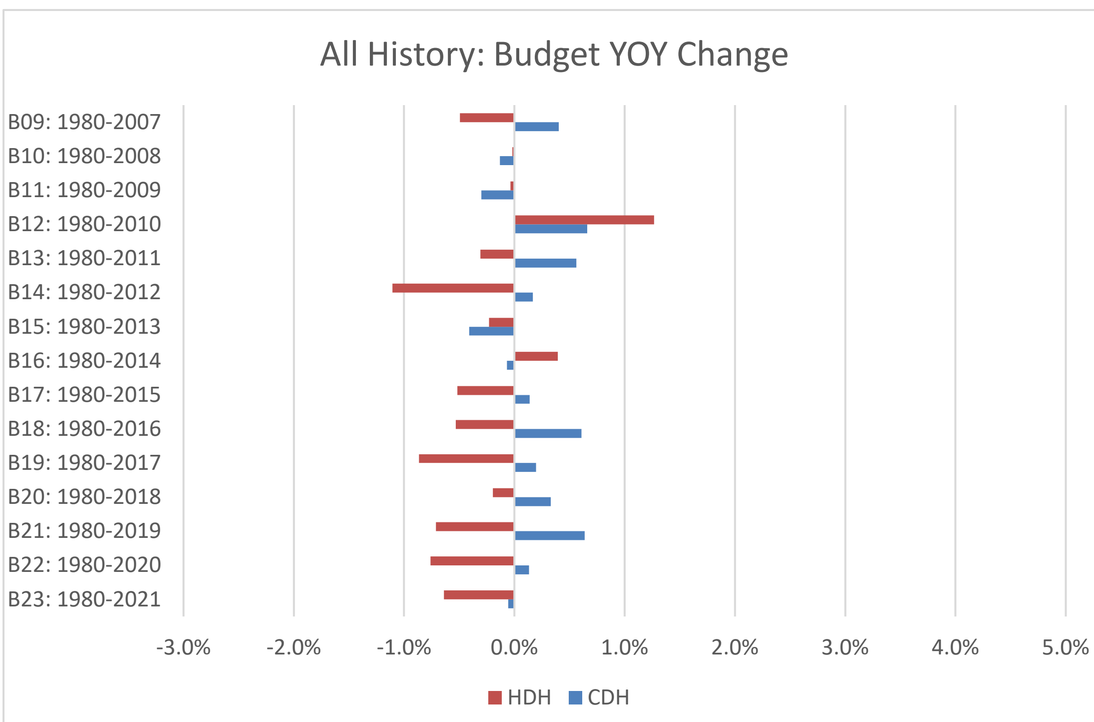
January's chart shows decreasing HDH from forecast to forecast where the dotted trend line for both cases is downward sloping. August's chart shows CDH for the same budgets, with the trend lines increasing. In both charts, the trends have the same signs, but the trend that uses all history is more muted compared to the 20-year definition. It should be noted, however, that the Company's methodology (depicted as red lines) is smoother, indicating more stability from year to year. The more subtle trend is a reasonable trade-off when considering the reduction in the annual swings from updating the weather normal definition each year.

Q. IS A 20-YEAR WEATHER NORMAL DEFINITION MORE VOLATILE THAN AN ALL-YEAR WEATHER NORMAL DEFINITION?

A. Yes. As shown in Figure 2 below, the 20-year weather normal definition is far more volatile than using all available history. From Budget 2009 ("B09") through Budget 2023 ("B23"), under the Company's methodology the percentage change in CDH from one year to the next is less than +/- 1%, while HDH is less than +/- 1% in all but two years. Using the 20-year normal definition, the same annual percent change in CDH is at or above +/- 1% five times, while HDH is at or greater than +/- 1% in half of the cases (eight times out of the sixteen budgets examined), including two years where the changes were -2.7% and almost +4%.

FIGURE 2: 20-YEAR VS. ALL HISTORY BUDGET YEAR OF YEAR CHANGE





Q. WHY IS IT IS BETTER TO USE AN ALL-WEATHER AVERAGE AS OPPOSED TO A 20-YEAR AVERAGE TO DEFINE WEATHER NORMAL?

A. Electricity usage in Georgia is highly weather sensitive. Therefore, the level of forecasted load is highly dependent on the weather assumed in the forecast. Using all the available weather history provides a more stable weather definition than using a 20-year rolling average, while still capturing the warming trends. For planning purposes, the weather volatility of a single year should be reflected in variances from normal weather but should not materially impact the definition of normal weather. The volatility introduced by a 20-year window would significantly impact the load forecast, making it highly susceptible to year-to-year swings introduced by simply adding the most recent year of history and dropping the oldest year. The 20-year definition would also impact the accuracy of the forecast and would make it less effective for IRP planning purposes and for identifying true underlying trends from other drivers.

Q. WHAT IS YOUR RESPONSE TO STAFF'S RECOMMENDATION TO UPDATE THE RESIDENTIAL SATURATION SURVEY EVERY THREE YEARS?

A. Georgia Power does not support continuing to update the residential saturation survey because it is an expensive undertaking. For reference, the cost to conduct the last residential saturation survey in 2016, which solicited feedback from customers via mail-in response, was $236,430. Rather, Georgia Power supports the use of the EIA's customer end use data, which is updated every one to four years depending on the data in question. The EIA information is publicly available and free of charge, which reduces costs for our customers. Further, the Company believes that using EIA's South Atlantic regional data provides good information on the saturation of end uses as it is based on a large data sample that was designed to meet precision requirements on energy consumption for all 50 states and

Washington D.C., all data undergoes a series of quality control checks to identify and resolve data inconsistencies, and results are analyzed to ensure that estimates are not statistically or practically different from the target population.[1]

III. DEMAND SIDE STRATEGY

Compliance with the Commission's DSM Policy and EISA

Q. DID THE COMPANY COMPLY WITH EACH OF THE FIVE MAJOR COMPONENTS STAFF IDENTIFIED AS PART OF THE COMMISSION'S CURRENT DSM POLICIES APPROVED IN THE 2010 IRP?

A. Yes. The Company treats cost effective energy efficiency as a priority resource, in compliance with the 2007 Federal Energy Independence and Security Act ("EISA"). The Company followed and developed its proposed DSM plan according to the DSM Program Planning Approach (formerly known as the Nine-Step DSM Planning Process). The Company actively participated in the DSM Working Group ("DSMWG") and was receptive to feedback from its members. The Company prepared and filed with the Commission a new energy efficiency potential study one year prior to the filing of the IRP. Finally, the Company used the Total Resource Cost ("TRC") test, Rate Impact Measure ("RIM") test, Societal Cost test, Program Administrator Cost ("PAC") test, and Participants test to evaluate its proposed DSM plan as required by Commission Rule 515-3-4-.04(4)(a)(2).

Q. DOES THE EISA STANDARD REGARDING ENERGY EFFICIENCY REQUIRE ANY SPECIFIC ACTION ON THE PART OF THE COMMISSION OR THE COMPANY?

A. No. Staff's testimony asserts that the Company failed to comply with EISA Standard 16 because the Company did not allow demand side resources to compete directly with supply-side resources in the Aurora model that was used to develop

[1] U.S. Energy Information Administration, 2020 RECS Technical Documentation Brief.

the Company's resource expansion plan in this IRP. (Tr. 769-70.) However, EISA Standard 16 only requires electric utilities to "(A) integrate energy efficiency resources into utility, State and regional plans; and (B) adopt policies establishing cost-effective energy efficiency as a priority resource."[2] EISA Standard 16 does not impose any specific obligation on the Company or the Commission to adopt a particular DSM policy, does not prescribe a specific way to evaluate DSM in related to supply-side resources, and does not specify or limit how an electric utility is to implement Standard 16.

EISA Standard 16 does not define or provide guidance on what it means to treat energy efficiency as a priority resource or on how to integrate energy efficiency into utility plans. There is no EISA requirement, or any other requirement, that energy efficiency resources be modeled alongside supply-side resources within the same model. As such, we disagree that the Company did not comply with EISA Standard 16. As confirmed at the Staff hearings on May 25, 2022, the Company's DSM portfolio was developed in a manner consistent with previous IRPs, which were approved by the Commission, and Staff's argument in this case, which is no different than what has been raised in prior IRPs, is simply its interpretation of EISA Standard 16.

Q. HOW DOES GEORGIA POWER INTEGRATE ENERGY EFFICIENCY INTO ITS INTEGRATED RESOURCE PLAN?

A. Before development of the supply-side plan, the first step in the Company's planning process is to reduce the peak demand and energy forecast by the impact of the Company's DSM programs. Consistent with the IRP statute, the Company's plan identifies and considers any present and projected reductions in the demand for energy that may result from approved energy efficiency programs. Thus,

[2] Energy Independence and Security Act, Pub. L. No. 110-140, 121 Stat. 1666 (2007) (codified in Public Utilities Regulatory Policy Act of 1978, 16 U.S.C. § 2621(d)(16)).

Georgia Power integrates DSM into its resource planning process by accounting for it first and modeling it as a load reduction.

Q. DO YOU AGREE WITH STAFF'S RECOMMENDATIONS TO MODIFY THE DSM PROGRAM PLANNING APPROACH TO INCLUDE AN ADDITIONAL SCENARIO WHERE DSM IS MODELED ALONGSIDE SUPPLY-SIDE RESOURCES?

A. No. The Company's current approach to DSM planning and modeling is comprehensive, follows industry standard best practices, and is consistent with prior IRPs where the Company's proposed plan was approved by the Commission. The Company determines an appropriate portfolio of DSM measures and programs to benefit its customers through a process that includes: (1) utilizing standard utility cost-effectiveness screening tools; (2) incorporating input from a variety of stakeholders; and (3) leveraging lessons learned through program delivery and program evaluation to create the proposed DSM portfolio. The Company's methodology already evaluates DSM on a level playing field with supply-side resources by utilizing the same underlying system assumptions in their evaluation, and the impacts of DSM are integrated in the system planning process as reductions in future capacity needs through the load forecast. As demonstrated through the Company's processes, DSM is given priority and reduces the Company's energy and demand forecast before supply-side alternatives are considered. The Company does not recommend modifying the DSM Program Planning Approach at this time.

Q. IS THE COMPANY'S DSM PLAN DEFICIENT OR INCOMPLETE FOR NOT MODELING DSM IN AURORA ALONGSIDE SUPPLY-SIDE RESOURCES?

A. No. As previously discussed, the Company is not required to model DSM resources alongside supply-side resources in Aurora. The Company's DSM White Paper satisfied the Commission's 2019 IRP Order, which directed the Company to evaluate whether DSM could be modeled against supply-side resources. The mere fact that the White Paper determined that it was possible to model DSM in the supply-side system does not mean that the Company supports doing so, that it was required to do so in this case, or that it is the best way to evaluate DSM going forward. The Company's existing approach is integrated and applies the same reference case, fuel prices, generation costs, and load forecast to both DSM and supply-side resources. Modeling DSM in the supply-side system requires additional steps that are not currently required and actually produces less accurate results than the existing approach. In addition, the supply-side modeling is not a replacement of the current methodology, it does not have the capability to calculate avoided transmission and distribution costs, or the upward impact on rates which has been a guiding principle of developing the DSM portfolio since the 2004 IRP.

Q. IS THE COMPANY'S PROPOSED DSM PORTFOLIO CONSISTENT WITH THE PRIOR DSM PLANS APPROVED BY THE COMMISSION?

A. Yes. The Company's proposed DSM portfolio is consistent with prior DSM plans approved by the Commission in design methodology and savings targets.

Q. HAS THE COMMISSION REVIEWED AND APPROVED THE COMPANY'S DSM PORTFOLIO DEVELOPED USING THE CURRENT PROCESS AND METHODOLOGIES IN THE PAST IRPS?

A. Yes. This Commission has reviewed and approved the Company's DSM portfolio based on the same development process and methodologies in each of the 2007, 2010, 2013, 2016, and 2019 IRPs.

Savings Targets and Budgets

Q. PLEASE RESPOND TO INTERVENOR REQUESTS TO INCREASE THE SAVINGS TARGETS FOR THE COMPANY'S PROPOSED CASE.

A. Several intervenors recommend the Company do more energy efficiency and DSM programs than the Company's proposed DSM portfolio. They proposed that the

Company set a savings target greater than 1% of the Company's retail sales or adopt the DSMWG's Advocacy Case. Not only is the 1% savings target arbitrary, as it does not consider any economic metrics, but such increased savings targets would require significantly higher budgets and increase upward rate pressure on customers regardless of whether they participate in Georgia Power's DSM programs. For example, in year three of the program cycle when the Advocacy Case reaches its proposed long-term savings targets, the Advocacy Case increases the cost of the DSM programs by 350% relative to year three of the Company's Proposed Case. The Advocacy Case also brings with it an annual average net present value of approximately $543 million of upward rate pressure to customers, which is almost two times the amount of rate pressure resulting from the Company's Proposed Case. This consideration is important for customers as a whole because most of the Company's customers do not participate in Georgia Power's energy efficiency programs. As a result, rates would increase for the vast majority of commercial and residential customers who do not participate in the Company's programs and who will not see offsetting reductions in energy usage.

Q. HAS STAFF RECOMMENDED ANY CHANGES TO THE COMPANY'S PROPOSED SAVINGS TARGETS?

A. Yes. Staff recommended that the Company's Home Energy Improvement Program ("HEIP") be expanded to include the proposed Manufactured Homes Program, without the whole home replacement measures, as outlined in the DSMWG Advocacy Case. With this addition, the energy savings targets for HEIP increase by 3 GWh per year and the demand savings increase by an average of 0.55 MW per year. In total, Staff's modification to the Company's Proposed DSM Plan increases the portfolio savings for all programs to 433 GWH per year for a total of 1,300 GWh for the 2023-2025 program cycle, compared to the Company's 431 GWh per year and 1,293 GWh through 2025.

Q. DOES THE COMPANY AGREE WITH STAFF'S PROPOSED RECOMMENDATIONS?

A. No. The savings target increase from Staff's recommendation is driven by the addition of the manufactured homes program, which is estimated to cost approximately $1.5 million. The Company does not believe that the additional 7 GWh of savings is worth the additional $1.5 million in costs. Furthermore, customers who live in manufactured homes are currently eligible to participate in the HEIP program, and the Company sees no reason to stand up a duplicate program with the same level of savings that could be attained from this customer group within the Company's proposed savings targets and budgets.

Q. WHY DID THE COMPANY PROPOSE TO USE DSM SAVINGS TARGETS CONSISTENT WITH WHAT WAS APPROVED IN THE 2019 IRP?

A. The Commission's 2019 IRP Order approved savings targets that were 15% higher than what the Company proposed in 2019. Due to the impacts of COVID-19, the Company did not meet its projected energy savings targets in either 2020 or 2021. As such, the Company believes the current DSM savings targets remain appropriate as Georgia Power's implementation of programs will return to normal from the disruptions caused by the pandemic. In addition, the economics of the Company's current and proposed DSM programs continue to worsen with the decline in avoided costs. With these lower avoided costs, the value of each kWh saved as a result of DSM participation has declined. It has become increasingly challenging for the Company to maintain the balance of maximizing economic efficiency while minimizing upward pressure on rates in accordance with Commission policy, particularly in the residential sector.

As stated in our direct testimony, the Company's recommendation to continue to offer DSM programs at this time is based on the desire to minimize market disruption, to continue meeting customers' expectations, and to maintain working relationships with vendors performing qualified program improvements. Even so, in light of worsening economics and additional upward pressure on rates, the Company's balanced proposal, as opposed to a more aggressive approach, is appropriate for this IRP.

Q. PLEASE RESPOND TO THE COMPARISONS MADE BY SACE OF THE COMPANY'S HISTORIC AND PROJECTED ENERGY SAVINGS TO THOSE OF OTHER STATES.

A. Comparisons with other states imply that each state has adopted a similar policy with respect to DSM, which is not the case. In reality, each state must reach its own unique determination regarding the policies that will guide customer-subsidized DSM implementation. For example, these policies will be impacted by numerous considerations such as the energy-intensity of customers in each state, the cost of electricity, capacity needs, regulatory structure, and other state-level initiatives like state energy efficiency and renewable energy portfolio standards and regional greenhouse gas initiatives.

Q. PLEASE RESPOND TO STAFF'S PROPOSED BUDGET MODIFICATIONS.

A. Staff recommends reducing the non-incentive budget for the Residential Behavioral Program and the Commercial Prescriptive Program by approximately $1.5 million and $6 million for the 2023-2025 program cycle, respectively. In addition, Staff has proposed to increase the HEIP budget by approximately $1.5 million to incorporate the addition of the Manufactured Homes program, without increasing the contracting or program administration costs. Staff's concerns over the Company's proposed non-incentive budgets for the 2020-2022 cycle are unwarranted. Staff faults the Company for budgeting more than it historically spent in the current cycle without accounting for the impact of COVID-19 on the Company's reduced spending. However, the DSM rider is trued up annually so that if the Company collects more than it spends, those funds are returned to customers almost immediately. Further, the Company does not support the addition of the

Manufactured Homes program within the HEIP or as a standalone program since the target market can already participate in the HEIP as currently structured.

Staff anticipates that non-incentive budgets should decline over time based on other utilities achieving economies of scale and more efficient deliveries as they gain experience. However, it is inappropriate to assume that non-incentive budgets will necessarily decline as a program reaches years seven to nine of implementation. Staff's position fails to consider that as a program matures, some of the customers that are easiest to reach or most willing to participate have already participated such that increasing participation among harder to reach customers can be more expensive and more time consuming. An arbitrary and blanket cap on non-incentive budgets ignores differences among DSM programs, such as substantial changes in similarly named programs or time in the market (e.g., the refrigerator recycling program began in 2007 whereas midstream HVAC started in 2017), that may require additional time, money, and effort to achieve the same level of savings previously achieved.

Evaluation of DSM Economics

Q. WHY DOES THE COMPANY CONTINUE TO UTILIZE THE RIM TEST?

A. The Company continues to utilize the RIM test because it is the only test that takes into consideration the impact of DSM programs on non-participants. The RIM test calculates the impact on customer rates due to changes in utility revenues and operating costs caused by the DSM program. The RIM test is the only one of the standard cost-effectiveness tests that reflects the revenue shift, as well as the other costs and benefits associated with the DSM programs, effectively showing the shifting of cost-recovery from DSM program participants to non-participants. Moreover, the Company is required to use the RIM test per the Commission's own IRP rules, and Commission DSM policy requires the Company to maximize economic efficiency while minimizing upward pressure on rates.

Q. WHY IS IT CRITICAL TO CONSIDER THE RATE IMPACT OF DSM MEASURES ON NON-PARTICIPANTS?

A. The Company strives to meet the electricity needs of all customers in an affordable manner and is, therefore, concerned with upward rate pressure. All things being equal, the rates and bills of non-participants will increase because of the Company's DSM programs. Consistent with Commission policy related to minimizing upward pressure on rates, it is appropriate for the Company to consider rate impacts when evaluating proposed DSM programs.

Q. WHY DOESN'T THE COMPANY USE THE RIM TEST FOR SUPPLY-SIDE RESOURCES?

A. With supply-side options, no revenue shift exists. All customers receive the collective benefit of the supply-side resource, and all customers pay a portion of the respective costs based on their usage. There is no need to identify participants and non-participants as all customers are served by supply-side resources. Also, supply-side resources do not directly change or reduce customer usage upon their deployment.

In contrast to most supply options, DSM programs cause a direct shift in revenues due to the programs reducing customer usage among participants. If reduced revenues from DSM programs exceed the electric production cost avoided by these programs, then non-participating customers' bills will increase to account for that difference. The RIM test is the only test that reflects this revenue shift to non-participants that results from DSM programs along with the other costs and benefits associated with the respective programs. Further, unlike supply-side options, the costs of DSM programs are not spread evenly across all customers since not all customers participate. Therefore, it is appropriate and in keeping with standard energy efficiency practices to use the RIM test for demand side resources only.

Q. IS THE COMPANY AWARE OF ANY UTILITY THAT USES THE RIM METHODOLOGY FOR EVALUATING SUPPLY-SIDE RESOURCES?

A. No. The Company is not aware of any utility that uses RIM to evaluate supply-side resources.

Q. SHOULD THE COMPANY IMPLEMENT MEASURES THAT PASS THE PAC TEST REGARDLESS OF RIM TEST RESULTS AS SUGGESTED BY SACE AND GIPL/PSE?

A. No. As required by the DSM Program Planning Approach and the Commission's IRP Rules, the Company applies the TRC test to determine whether a DSM measure or program should be included in the Company's DSM portfolio. While the PAC test is informative, it ignores the cost shift that occurs between participating and non-participating customers in energy efficiency programs. Implementing measures that pass the PAC test but fail RIM would only reduce energy costs for participating customers while increasing rates for non-participating customers.

Q. GIPL WITNESS DR. COX SUGGESTED THAT "OVER TIME," ADOPTION OF DSM PROGRAMS WITH FAILING RIM VALUES COULD REDUCE BILLS FOR NON-PARTICIPATING CUSTOMERS. IS THIS ASSERTION TRUE?

A. No, this statement is not true. A failing RIM test indicates that the bill savings of participating customers will exceed the avoided electricity cost realized by the utility. Because of this fact, it would be mathematically impossible for non-participants to save on their bills over time by adopting DSM programs with failing RIM values.

Q. WHY IS TRC A MORE APPROPRIATE TEST UPON WHICH TO BASE DECISIONS THAN THE PAC TEST?

A. The TRC test provides a more robust view of benefits for participating customers by recognizing the full incremental cost of a measure, as well as non-electric energy benefits realized by the participating customer. In the same way that replacing a gas-powered automobile with an electric vehicle would consider gas savings in addition to higher electricity bills, the TRC test considers all the costs and benefits of energy efficiency measures. As mentioned previously, although the Company considers the PAC test, RIM test, Societal Test, and Participants test, the results of any one of these tests individually is not determinative of whether it is appropriate to include or exclude a DSM measure or program. Moreover, the Commission's IRP Rules require that each DSM program pass the TRC test in order to be included in the Company's DSM portfolio.

DSM Programs/Tools

Q. DOES THE COMPANY SUPPORT GIPL, PSE, AND SACE'S REQUEST TO ADOPT THE ADVOCACY CASE?

A. No. The cost and upward rate pressure the Advocacy Case places on customers does not justify the potential achieved savings it proposes. In addition, all the additional programs included in the Advocacy Case over and above what is included in the Company's Proposed Case either do not make sense for customers, are contrary to current Commission policy, or are duplicative of efforts the Company has already undertaken with regards to making its system more efficient.

Q. WHAT IS THE COMPANY'S OBJECTION TO THE MANUFACTURED HOMES PROGRAM INCLUDED IN THE ADVOCACY CASE?

A. The target market of the existing home aspect of the manufactured home program is already served and able to participate in the Company's HEIP as currently structured without duplicative administrative and marketing costs. The Company does not believe the additional costs required to stand up another program will result in the savings projected by SACE. In the replacement aspect of their program, there is no guarantee that the incentives provided to manufacturers will lower the customer's purchase price of the energy efficient manufactured home or the energy that it uses. In addition, the replacement component of this program is not feasible to be implemented in Georgia Power's service territory since there is no guarantee that the upgraded manufactured home will remain within the Company's service territory or even in Georgia.

Q. DOES THE COMPANY AGREE WITH SEVERAL INTERVENORS THAT MORE OF ITS PROGRAM SAVINGS SHOULD BE GEARED TOWARDS INCOME-QUALIFIED CUSTOMERS?

A. No, the Company believes the program plans it put forth in this IRP are a proper balance for all customers in the residential and commercial classes. Although the Company's request includes a dedicated increased savings target for Income-Qualified ("IQ") customers by over 300%, approximately 30% of the overall portfolio of residential DSM program savings are targeted toward IQ customers. The remaining 70% is targeted towards all residential customers, which may include additional IQ customers. Being that all residential customers pay into the DSM tariff, Georgia Power believes that it is important for all residential customers to have the opportunity to participate in the Company's DSM programs. From a commercial perspective, all proposed kWh savings are open and available to the general commercial class. While there is opportunity, and the Company will make efforts to reach marginalized businesses, those supporting IQ communities and historically under-performing businesses, the Company feels it is important to make these programs available to all commercial customers who contribute to the DSM tariff.

Q. DOES THE COMPANY AGREE WITH THE COMMISSION THAT STANDARD LED BULBS ARE NEARING MARKET TRANSFORMATION?

A. Yes, the Company does agree, which is why its proposed Residential Lighting program is putting significant focus on specialty lighting that has much lower market penetration than standard lighting types. The Company is also proposing to ramp down savings year-over-year in its DSM Application. This plan is to further account for the nearing of market transformation with this program.

Q. WHY DOES THE COMPANY PROPOSE TO DISCONTINUE USE OF THE AUTOMATED BENCHMARKING TOOL ("ABT")?

A. As was the case in 2019, neither the Company nor the third-party that evaluated the tool has seen evidence that the ABT provides value to the majority of Georgia Power's commercial customers. While all commercial customers paid for the development of the tool, more than 50% of the time this tool has benefited only five users. In addition, there are no proven customer savings from participants who have used the tool and there is no evidence that the tool has led to increased participation in the Company's DSM programs. The tool was developed out of the stipulated settlement in the 2016 IRP and is not a certified or planned DSM program. The Company does not believe the limited value gained from the tool merits its continued operation.

Q. PLEASE RESPOND TO STAFF AND THE LOCAL COALITION OF GOVERNMENTS' WITNESS SEYDEL'S RECOMMENDATIONS TO CONTINUE USING THE ABT.

A. Despite agreeing with the Company that there are few direct savings attributable to the tool, Staff argues that the ABT should be continued for the 2023-2025 program cycle because it offers building owners the ability to access their aggregated whole building usage data without significant barriers or costs. (Tr. 789.) Instead, Staff appears to support socializing the access cost of the tool across the entire commercial customer class. The Company's recommendation to discontinue providing this tool would not significantly impact current users and interested customers as they have access to similar software tools in the marketplace. The website EnergyStar.gov includes links to 91 software companies, consultants, and other non-utility providers that offer a similar service. Each customer using the tool would simply have to pay for their use rather than having their access subsidized by the rest of the customer class.

Witness Seydel, on behalf of the Coalition for Local Governments, advocates that the ABT be continued as a core DSM program rather than a subscription-based offering. He asserts that several governments in the coalition have or are developing building performance standards that will use the tool to drive real reductions in building energy use. (Tr. 1185.) However, Witness Seydel could offer no support for this claim or evidence to suggest that real energy savings would be realized.

Furthermore, Witness Seydel alluded to the fact that the cities of Atlanta and Savannah have not seen energy savings from their use of ABT as a result of lower building occupancy and the impacts of COVID-19 over the last two years. (Tr. 1221-22.) It should be noted that the majority of both cities' use of ABT occurred in 2018, well ahead of the COVID-19 impacted years of 2020 and 2021.

Q. DOES THE COMPANY AGREE WITH WITNESS COX THAT THE COMPANY'S PROPOSED DSM PLAN IS A DISPATCHABLE RESOURCE?

A. No, this is not an accurate statement as it pertains to the Company's proposed DSM plan in this IRP. Witness Cox stated that demand response ("DR") is a component of DSM, and therefore, implies that DSM is a dispatchable resource. (Tr. 1411-12.) While DR is a dispatchable resource, extrapolating this characteristic to the entire DSM plan grossly misrepresents the fact that the vast majority of the DSM plan submitted by the Company in this IRP is targeted energy savings, not DR.

Q. DOES THE COMPANY AGREE WITH SACE AND SOUTHFACE WITNESS BROWN THAT THE WATER HEATER DR PILOT SHOULD BE EXPANDED?

A. No, the Company does not support expanding the water heater DR pilot at this time. Pilots should be completed and properly evaluated before any decision is made to expand or certify them. The point of pilots is to determine if a technology works in a cost-effective manner and to inform formal program design at lower risk of increasing DSM-related costs for customers.

Certified Cost of DSM Programs and Additional Sum

Q. WHAT DSM COSTS ARE THE COMPANY ASKING THE COMMISSION TO APPROVE?

A. As in previous IRPs, the Company is requesting Commission approval of the costs for all approved and certified DSM programs, pilots, and other DSM activities. In addition, the Company requests the continued collection of an additional sum amount. The budgets and costs for the Company's DSM programs are set forth in Appendix C to the DSM Application, and the additional sum amounts are set forth in Appendix F to the DSM Application.

Q. PLEASE DESCRIBE THE COMPANY'S REQUEST FOR AN ADDITIONAL SUM.

A. As stated in the DSM Application, the Company requests an additional sum equal to four cents for every kWh saved using verified gross energy savings values applied to all certified DSM programs in the residential and commercial DSM portfolios. Moreover, the Company proposes a tiered scale approach to encourage achievement of certified energy savings goals while ensuring cost-effective program implementation. Under this approach, if the reported energy savings grow higher than 120% of certified energy savings goal by class, or as a portfolio during any year within the IRP cycle, the additional sum on the reported savings beyond 120% will be collected at five cents per kWh saved. Any authorized additional sum will be specific to the corresponding customer class and will be collected through the Residential and Commercial DSM tariffs.

Q. WHY DOES THE COMPANY WANT TO CHANGE THE ADDITIONAL SUM METHODOLOGY?

A. The proposed additional sum methodology is simpler than the existing methodology and likely to be more stable. The proposed change in methodology also better aligns the additional sum with the energy savings achieved from the customer classes eligible to participate in the Company's residential and commercial DSM programs. Furthermore, under the current methodology, the Company is projected to receive zero additional sum on four residential programs and very little to no additional sum from a fifth residential program. The additional sum must be a non-zero number to appropriately incentivize DSM offerings. Finally, the Company's proposed approach will also help streamline the reporting process and provide additional clarity around the annual DSM tariff true-up process.

Q. DOES STAFF AGREE THAT THE COMPANY SHOULD RECEIVE AN ADDITIONAL SUM FOR IMPLEMENTING DSM PROGRAMS?

A. Yes. In Staff's testimony, Staff indicated that additional Sum was essential in providing the Company a clear financial interest in the success of energy efficiency and demand response programs. (Tr. 801.) Staff acknowledges that the additional Sum incentive plays a key role in the Company's decision-making and planning processes relating to the IRP. *Id*.

Q. WOULD THE COMPANY'S PROPOSED ADDITIONAL SUM METHODOLOGY PROVIDE AN INCENTIVE TO IMPLEMENT DSM PROGRAMS FOR THE RESIDENTIAL CLASS?

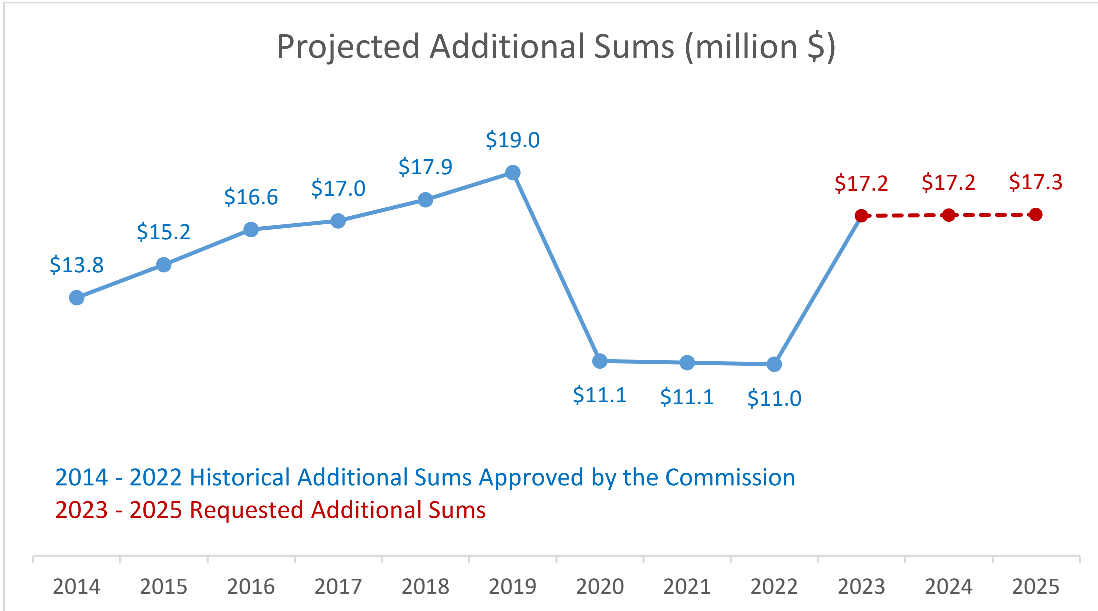
A. Yes. The Company's proposed Additional Sum methodology would provide an

Additional Sum for implementing residential and commercial DSM programs based on and consistent with the amount of kWh savings achieved.

Q. DOES STAFF EXHIBIT BCS-15 ACCURATELY REFLECT AND COMPARE THE COMPANY'S ADDITIONAL SUM UNDER THE CURRENT AND PROPOSED METHODOLOGIES?

A. No. Staff's estimated historical average (i) ignores the impact of COVID-19 on the Company's DSM programs and (ii) understates the average additional sum to make the comparison against the Company's current request seem out of proportion. Staff Exhibit BSC-15 compares the actual additional sum collected by the Company to the projected additional sums the Company could earn in the 2023-2025 program cycle under the existing and proposed additional sum methodologies. This comparison is incorrect. A more accurate comparison would be to compare the projected additional sums historically approved by the Commission for the years 2017 through 2021 as shown in Figure 3 below. Moreover, by using actual additional sums earned from calendar years 2020 and 2021 in the calculation of the average additional sum, Staff's estimate of additional sum is biased and disproportionately lower than it would be if the full slate of data on the Company's actual additional sums provided in response to data request STF-GDS-1-23 was considered.

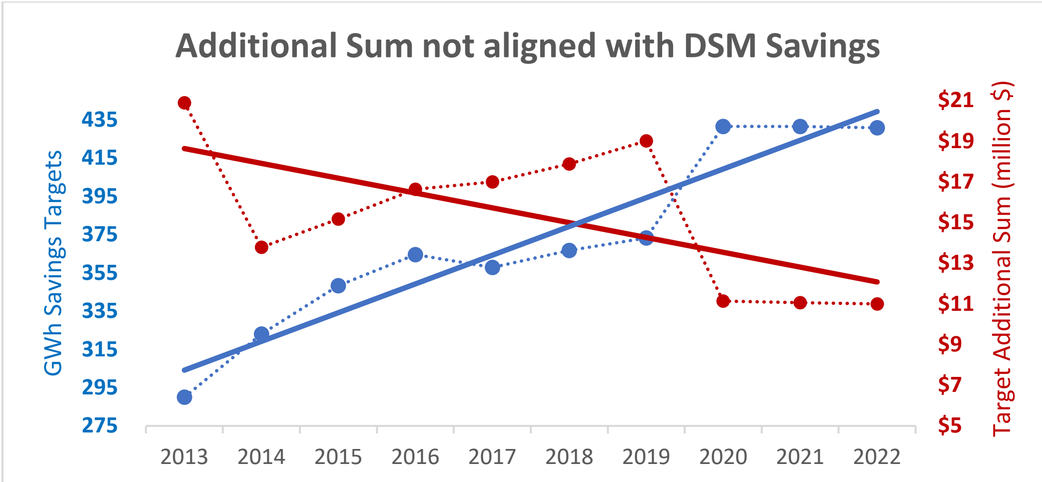
FIGURE 3: PROJECTED ADDITIONAL SUMS



Q. HOW DOES THE COMPANY'S ADDITIONAL SUM COMPARE WITH ENERGY SAVINGS?

A. Since 2013, the Company's energy savings in GWh have steadily increased year after year. Contrary to this trend, in the same period, the Company's projected additional sum has decreased. As shown in Figure 4 below, the trend in the Company's additional sum is not currently aligned with the DSM savings it has achieved (declining compensation for higher savings delivered). This is one of the main drivers of the Company's request to modify the additional sum methodology.

FIGURE 4: TARGET ADDITIONAL SUM NOT ALIGNED WITH DSM SAVINGS



Note: The dotted lines in Figure 4 represent historical Commission-approved energy savings and additional sum targets. The solid lines represent linear trend lines of this data.

Q. WHY IS THE COMPANY'S PROPOSED ADDITIONAL SUM REASONABLE?

A. The Company's proposed additional sum eliminates the fact that most of the requested residential class of programs are projected to have a $0 additional sum associated with them under current methodology. Under Staff's proposed methodology, four of the seven residential programs would have a $0 additional sum each year and a fifth program would average less than $20,000 a year. This result would be in direct contrast to Staff's testimony that an Additional Sum was essential in providing the Company a clear financial interest in the success of DSM programs. (Tr. 801.)

Q. DOES THE COMPANY'S PROPOSED ADDITIONAL SUM MEET THE FOUR PRINCIPLES IDENTIFIED BY STAFF IN ITS TESTIMONY?

A. Yes. In fact, the Company believes that its proposed additional sum methodology better meets the four principles for DSM incentive mechanisms outlined in the November 2007 National Action Plan for Energy Efficiency Report titled

"Aligning Utility Investments with Investment in Energy Efficiency," than the current methodology. The Company's proposed methodology:

(1) Strikes an appropriate balance of risks and rewards between utilities and customers;

(2) Promotes stabilization of customer bills and rates;

(3) Stabilizes utility revenues; and

(4) Improves administrative simplicity and management of regulatory costs.

Q. DOES THE COMPANY AGREE WITH STAFF'S CONCERN THAT GEORGIA POWER'S PROPOSED ADDITIONAL SUM WILL INCENTIVIZE THE COMPANY TO IMPLEMENT ENERGY EFFICIENCY MEASURES THAT HAVE A SHORT USEFUL LIFE?

A. No. Staff provides no evidence to support this concern. The Company does not build its DSM programs based on the useful lives of the measures in its programs or the additional sum it will earn from the program. Among other things, the Company builds its DSM programs based on measure potential, historical measure and program performance, and input from Staff and members of the DSMWG. If the Commission or Staff is worried about what measures the Company is incentivized to include in its programs, they can modify or reject programs that insufficiently balance measures with short and long lives.

Q. ARE STAFF'S COMPARISONS OF THE COMPANY'S ADDITIONAL SUM PROPOSAL TO OTHER STATES RELEVANT TO GEORGIA POWER'S REQUEST?

A. No. Staff compares the Company's proposed additional sum methodology to Connecticut, Michigan, and Ohio to suggest that other states achieve greater energy savings with less incentive. However, the Commission should not give this comparison any weight since each of these three states is in a jurisdiction where energy efficiency savings and targets have been mandated by statute or other regulation pursuant to an energy efficiency standard. This is a significant difference in the starting point from which each utility is working and for which an incentive may apply. As such, the comparisons offered by Staff are inapposite.

Q. DOES THE COMPANY HAVE CONCERN WITH STAFF'S ASSUMPTION THAT ADDITIONAL SUM, UNDER THE CURRENT METHODOLOGY, COULD RETURN TO LEVELS THAT IT WAS ORIGINALLY INTENDED TO BE?

A. Yes. Based on long-term trends in declining avoided costs over the last several IRP cycles, as well as the Company's projection that avoided costs will continue to decline or stay at lower levels, Staff's claims that additional sum could increase with their proposed methodology is highly unlikely over the next three-year cycle. (Tr. 884.) In addition, Staff provided no analysis to support this assertion.

Q. WAS STAFF'S CONTENTION THAT ACTUAL RESIDENTIAL ADDITIONAL SUM MAY BE NON-ZERO COMPARED TO WHAT WAS PROJECTED DURING THE PLANNING PROCESS CORRECT?

A. No, Witness Cooper's statement is not supported by the Company's historical data. (Tr. 877.) The chart below shows that, over the last two program cycles, the majority of programs earned an additional sum of $0 year-over-year despite projected additional sums estimating much larger incentives.

	Program	2017	2018	2019	2020	2021
Additional Sum	Lighting	$ 1,375,348	$ 987,005	$ 1,671,228	$ 1,346,381	$ 1,331,230
	Behavioral	$ -	$ -	$ 45,537	$ -	$ -
	Refrigerator Recycling	$ -	$ -	$ -	$ -	$ -
	New Homes	$ -	$ -	$ -	N/A	N/A
	HEEAP				$ 211,143	$ 250,434
	Home Energy Improvement	$ 2,379,443	$ 1,740,914	$ 434,914	$ 95,229	$ 110,749
	Tstat DR				$ -	$ -
	Power Credit	$ -	$ -	$ -	N/A	N/A
	Res HVAC	$ -	$ -	$ -	N/A	N/A
	RES TOTAL	**$ 3,754,791**	**$ 2,727,919**	**$ 2,151,679**	**$ 1,652,753**	**$ 1,692,412**

Q. HOW DOES THE COMPANY RESPOND TO INTERVENOR REQUESTS TO RESTRICT GEORGIA POWER'S DSM ADDITIONAL SUM UNLESS THE DSM PROGRAM LEADS TO IMPROVED ENERGY SAVINGS?

A. SACE and the Commercial Group advocated for restrictions on the Company's additional sum due to alleged increases in costs to customers without corresponding increases in energy savings. However, the achievement of energy savings is not one of the three considerations the Commission is directed to consider in setting the additional sum. As provided in the DSM statute, the Commission should consider lost revenues, shared savings, and changed risks in determining an appropriate additional sum for the Company's DSM programs. In addition, Commercial Group proposes to limit the Company's additional sum based on the average revenue requirements caused by DSM programs during COVID years 2020 and 2021. By tying the additional sum to performance during the pandemic, the Commercial Group aims to unfairly limit the Company's incentive based on lower-than-expected performance for reasons wholly outside Georgia Power's control.

Q. IS THE COMMERCIAL GROUP CORRECT IN ASSERTING THAT THE COMPANY'S PROPOSED ADDITIONAL SUM IS OUT OF LINE WITH THE COST OF COMMERCIAL ENERGY?

A. No. The Commercial Group's claim that the proposed additional sum of four cents per kWh saved is out of line with the typical cost of commercial energy in a non-COVID year (e.g., 2020 and 2021) is not correct. First, the cost of commercial energy and the additional sum are not accurate comparisons. Rather, at base, the Commercial Group argued that the Company's additional sum shouldn't exceed the amounts earned during COVID. However, it is more accurate to compare the Company's proposed 4 cents/kWh additional sum to prior additional sum amounts. When compared against the historical approved additional sums shown in Figure 3, the Company's requested additional sum is more in line and therefore not unreasonable.

IV. <u>DER CUSTOMER PROGRAM</u>

Q. WHY IS IT APPROPRIATE FOR THE COMPANY TO OWN THE DER ASSETS PROPOSED FOR RAST-1?

A. For customers participating on RAST-1, Georgia Power has proposed to design, procure, install, own, operate, and maintain a dispatchable DER behind the customer's meter to meet their resiliency needs. For those RAST-1 customers that choose to participate in DRC-1, those assets will be further leveraged to strengthen grid reliability for all customers. RAST-1 assets will facilitate and provide demand response benefits by their utilization through DRC-1. Therefore, Company ownership of the participating DER is necessary to ensure all customers can realize those benefits. Unregulated third party-owned assets can and do provide localized backup solutions to customers, but such assets cannot be relied on in the aggregate to provide unfailing service during critical reliability events. Georgia Power cannot wait until a reliability event happens and hope that a third party-maintained asset is available to be called upon; it must be available. Company ownership, with direct operational and maintenance oversight, will ensure the participating DER will respond as needed during reliability events. During times of critical reliability events, our customers will be relying on DRC-1 to help keep the lights on. The operation of these assets and the responsibility lies with Georgia Power as the responsible utility, under direct oversight of the Commission.

Q. WHAT OPERATIONAL RISKS WOULD THIRD PARTY ASSETS' PARTICIPATION IN DRC-1 POSE?

A. Third party-owned DER introduces risks related to selecting equipment and vendors that do not meet minimum requirements, such as those related to weatherization, certification, and permitting requirements, and thus decrease the asset's reliability. Additional operational risks include testing, alarm response, proper commissioning, fueling strategies, and repair. All these factors impact the ability of DER to respond for customer resiliency and System reliability events.

Additionally, for Georgia Power to attempt to administer these requirements on third party-owned assets through tariff parameters or contractual elements would greatly add to the administrative burden and cost of the program.

Q. DO YOU AGREE WITH STAFF WITNESSES ALVAREZ AND STEPHENS THAT THE DER CUSTOMER PROGRAM WILL HARM THE DER MARKET IN GEORGIA?

A. No, and no evidence was provided to support that argument. In fact, the opposite is true in that the market in Georgia will benefit from the DER Customer Program in several ways. First, the Company will primarily leverage existing expertise from Original Equipment Manufacturers ("OEMs") and Engineering, Procurement, and Construction ("EPC") contractors in the DER market in implementing the program. Second, the DER Customer Program will also provide economic benefits to customers seeking resiliency solutions by leveraging DER for the good of all customers through DRC-1 and further growing the DER market. Last, as certain segments of commercial and industrial customers are increasingly seeking resiliency solutions, having a regulated offering, in addition to that offered by existing unregulated providers, will provide an additional option from which customers, including those looking to relocate to Georgia, can choose.

Staff Witnesses Alvarez and Stephens' claims were based on general assumptions and unsubstantiated opinions. The DER Customer Program will have the same financing structure and procurement opportunities that Georgia Power's longstanding regulated lighting business and unregulated DER business have leveraged. Staff Witness Alvarez admitted that he was not aware of Georgia Power's unregulated DER business nor familiar with the details of Georgia Power's lighting business before he claimed such a competitive advantage would "harm the DER market in Georgia." (Tr. 590-91.) Staff Witnesses Alvarez and Stephens' testimony that Georgia Power's cost of capital is "most likely lower than almost every one of its C&I customers" was admittedly not based on any data or analysis other than “simply comparing the size of various companies.” *Id.* A company’s financing costs are comprised of their unique debt costs, equity costs, and capital structure. It is impossible to judge a potential financing advantage in a market based solely on size. Moreover, this unsupported claim regarding cost of capital was made without any analysis of the customers potentially participating in the DER Customer Program.

Q. WHAT BAD DEBT RISKS DO NON-PARTICIPANTS BEAR FROM THE DER CUSTOMER PROGRAM?

A. Very little. The DER Customer Program is limited to customers with a resilience need of 1 MW or greater. This population of customers realizes bad debt expense very rarely. For instance, only 14 accounts above 1 MW were written off in the last five years. Additionally, only a subset of customers above 1 MW are likely to participate in the DER Customer Program, and Georgia Power will have the ability to shape the contractual arrangements to protect non-participants from any cost shifting. The DER Customer Program and associated contracts will have credit qualifications, potential letters of credit, insurance terms, and protection from early termination by the participating customer to protect non-participants from bearing any cost of the DER Customer Program.

Q. DOES THE COMPANY’S INTERRUPTIBLE PROGRAM, DPEC-4, ACCOMPLISH THE SAME OBJECTIVES OF THE DER CUSTOMER PROGRAM AS STAFF HAS CLAIMED?

A. No. The goal of the DER Customer Program is to keep Customer’s operations uninterrupted, which is the opposite of the objective of DPEC-4, a program based on interrupting or altering the customer’s operations. Additionally, the economic proposition and value are very different between the two programs. Demand response from DRC-1 is facilitated by a firm asset, which enables long-term demand response contracts for up to the life of the DER. DRC-1 provides a levelized credit value over the contract life, which is dependent on the capacity equivalence of the demand response and the length of the contract with the customer. DPEC-4 requires annual contracts with enrolling customers and does not require the installation of a DER. The credit value for DPEC-4 is evaluated in rate case proceedings, typically every three years, and is based on a shorter-term value.

Q. WHAT ARE THE BENEFITS OF THE DER CUSTOMER PROGRAM AND WHY SHOULD IT BE APPROVED NOW?

A. The DER Customer Program leverages DER to strengthen grid reliability for all customers, creates a more flexible and diverse resource mix, promotes cleaner DER resources, and increases resilience for Georgia Power's participating customers. The DER Customer Program, including both RAST-1 and DRC-1, provides demand response value and corresponding system reliability benefits for all customers during a system reliability event, while also supporting commercial and industrial customers with enhanced resiliency needs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BY MS. PRYOR:

Q Mr. Valle, on June 13, 2022, did the Georgia Public Service Commission and Public Interest Advocacy Staff and Georgia Power Company enter into a stipulation regarding Docket No. 44160 and 44161?

A Yes.

MS. PRYOR: And, Madam Chair, the stipulation has already been admitted into the record as Georgia Power Exhibit 20.

And with your permission, I would like Mr. Valle to summarize the DSM and DER portions of the stipulation at this time.

MADAM CHAIR PRIDEMORE: Go ahead, sir.

WITNESS VALLE: Good afternoon, Commissioners. As you know, earlier -- I mentioned earlier today the company has signed a stipulation. On behalf of stipulated parties, we ask that the Commission approve the stipulation as a reasonable resolution of Georgia Power's 2022 IRP and DSM cases.

As we are direct testimony, our panel is here to support the company loads and energy forecast demand side management plan and DER request. The stipulation continues the long-standing history of collaboration and compromise between the company and PIA staff, which takes into account many of the

issues raised by intervenors in this proceeding. As with any settlement, no single party received everything they advocated for or requested, and compromises were made on many complex issues.

The stipulation as a whole represents a fair and balanced outcome of these proceedings, which we believe will provide significant benefits to our customers. In the interest of time, we will take this opportunity to highlight several items included in the stipulation that received significant attention during these proceedings.

The company agrees to update its residential customer separation survey and incorporate information collected into the 2025 IRP as appropriate. The company also agrees to file, in the 2025 IRP, a forecast sensitivity of Georgia Power's peak demand and energy forecast using weather normal data for the most recent 20 years.

As agreed to in the stipulation, in its 2025 IRP, the company will replace the aggressive case sensitivity with an additional sensitivity case where DSM resources, including demand response and energy efficiency, will compete head to head with supply side options in the company's IRP model as a selectable resource. Steps 8 and 9 of the DSM program planning process have has been adjusted to account for this change.

The demand side management working group will continue in its present form and be involved in the development of future DSM programs in the same manner as it has incorporated in past IRP cycles. The stipulation recommends approval of the company's requested certifications, decertifications, amended certificates, and rule waiver for the residential thermostat DR program.

The company's RISE pilot and automated benchmarking tool will continue for the 2023 to 2025 program cycle. The home energy improvement program will be expanded to include the proposed manufactured home program, except for the whole home replacement measure, and the DSM savings target will be adjusted accordingly to account for this expansion.

The DSM program budget will include a reduction of nonincentive costs for certified programs by a total of $4 million over the three-year program cycle. The current DSM process will continue, including not allowing the rollover of unspent annual budget dollars or unrealized saving targets. The company will earn an additional sum of

9.5 percent of shared savings pursuant to the current Commission-approved methodology.

Finally, as provided in the stipulation, the DER customer program, including the demand response credit tariff and the resilience asset service tariff, is approved on a pilot basis with an overall cap of 250 megawatts.

The tariffs and contract terms and conditions will be designed to eliminate hard to nonparticipating customers to the extent reasonably possible. Within four months of the Commission's final order in this proceeding, the company agrees to collaborate with the Commercial Group and commission staff to develop these elements of the DER pilot program.

By compromising on many of the contested matters in this IRP, the stipulated parties struck a fair balance between the different interests represented in this proceeding. This stipulation represents a positive outcome for our customers, and we recommend the Commission approve the stipulation as filed.

Thank you, Commissioners.

MS. PRYOR: Thank you.

The witnesses are now available for questions from the commissioners and for cross-examination.

MADAM CHAIR PRIDEMORE: Commissioners, questions for this panel?

(No Response.)

MADAM CHAIR PRIDEMORE: Georgia Public Service Commission?

MR. WALSH: No cross, Madam Chair.

MADAM CHAIR PRIDEMORE: Okay. Americans for Affordable Clean Energy?

(No Response.)

MADAM CHAIR PRIDEMORE: Not present.

Commercial Group?

(No Response.)

MADAM CHAIR PRIDEMORE: Not present.

Georgia Association of Manufacturers?

(No Response.)

MADAM CHAIR PRIDEMORE: Not present.

Georgia Coalition of Local Governments?

MS. BROWN: Yes, ma'am.

Good afternoon, Commissioners and Panel.

CROSS-EXAMINATION

BY MS. BROWN:

Q Can I direct you to page 3 of your testimony?

A (Witness Phillips) The rebuttal testimony?

Q Yes, your rebuttal testimony.

The company takes the position in the rebuttal testimony that the proposed savings targets are where they should be and that they should not be raised any further. And the reason for this seems to be a concern about upward pressure on rates.

Is that a fair summary?

A (Witness Phillips) Yes, upward pressure on rates is a consideration in developing the company's proposed case.

Q When we look at how these DSM costs are recovered through the DSM rider, how would you say that the cost of that rider on the average residential bill compares to, say, the fuel cost recovery rider? Is it higher? Is it lower?

A (Witness Phillips) I don't know specifically how it relates.

Q Do you know what percentage of the base rate the DSM rider is currently set at?

A (Witness Phillips) I don't recall, ma'am.

Q Would you be surprised if I told you that for the average customer using a thousand kilowatt hours, they spend 2,887 on fuel and 86 cents on DSM?

A (Witness Phillips) Subject to check, I think we can agree to that.

Q And would you say that -- would you be

surprised to hear that the average customer spending a thousand kilowatt hours spends 1,587 on environmental compliance cost recovery and 86 cents on DSM?

A (Witness Phillips) We haven't done that. I haven't done that analysis, but we'll continue --

Q That's subject to check?

A Sure.

Q So if that's the case, if you're paying 86 cents for an average customer using a thousand kilowatt hours, and assuming those costs scale with the savings targets, you could triple your savings targets for less than a single gallon of fuel right now.

Would that math be reasonable?

A (Witness Phillips) I haven't done that analysis, so I can't speak to that.

Q Yes, but would 86 cents times three be less than a gallon of gas right now?

A (Witness Phillips) Okay. Yes, I would agree with that. Sure.

Q So I understand, some customers, even a few dollars can be challenging for them.

But if the math is correct, subject to check, should we be pairing back our savings ambitions over those $3, or should we be trying to target programs to customers who really need them?

A (Witness Phillips) Well, I can speak to the DSM economics, and Witness Smith may be able to speak to the other part of your question. We -- subject to check, you know, with your analysis; I don't doubt your numbers, but when we developed the company's proposed case, we look at a number of factors.

We look at prior Commission policy -- or prior policies set for by this Commission, we look at the potential study, and we look at past program performance. And in this IRP, when considering those factors, we set -- or developed the company's proposed case to balance maximizing economic efficiency while minimizing the upward pressure on rates.

And so while your numbers seem reasonable comparing these increases with the cost of gas, when expanded to company-wide and to all of the projections, it does equate to significant upward pressure on rates. For the company's case -- or excuse me -- the proposed case, the three-year average upward pressure on rates is 283 million.

Compare that with the advocate's case, the three-year average is 543 million. So when you look at the overall portfolio, these are significant cost pressures, and we consider that in developing the overall proposed case and developing and striking -- or striving to strike that balance between maximizing economic efficiency while minimizing upward pressure on rates.

WITNESS VALLE: And, Commissioners, I would like to also clarify that there is a timing issue here with this comparison that is not completely apples to apples. If we compare the cost of fuel today, that will be reflected into the avoided costs of the future, versus the DSM rate, that was settled in the past and is sort of catch-up over time. So that is important.

But over time and overall, the avoided costs capture the fuel, the avoided costs of transmission generation and distribution, and compares that with the savings that DSM participants get.

So I think, in the morning, the commissioners mentioned something that is very important. Our mandate is really to look for all our customers, not just some participants, not just a small group. And every time a portion of our customers receive a benefit that is higher than the avoided costs, then you will experience revenue shifting, meaning that the nonparticipants will pay the participants and will subsidize them for the program to be effective.

So where you start making these comparisons that may be, you know, having timing issues that, you know, high prices, high natural gas, like it was discussed in the morning, is not part of the '22 because it was done before the Ukraine War and all this crazy world we live in. You can jump into conclusions. But the capturing of the avoided costs is meant to reflect all of that over time.

BY MS. BROWN:

Q But are those time shifts of revenue not common? Like, for instance, hydrofacilities that were built 80 years ago are providing low-cost energy today, but cost ratepayers in the past.

Is that not common?

A (Witness Valle) I don't think I follow your question. Could you please rephrase it?

Q Yes.

Long-lived resources, like, say, nuclear hydroelectric, they were paid for years ago, but they're still providing low-cost energy today, or that is the argument that's being made for future resources.

So is it not common that you may pay for a resource today, and it may be that the people who are paying for it don't receive all the benefit?

A (Witness Valle) Yeah, and that is also the case when we evaluate the DSM programs. It's not just for the year or the cycle in the IRP. It's considering the life of the measure or the program to give the full long benefit. So if the program lasts a year, it will get the benefits and costs of that year. If it lasts for 15, it will have those reflected into the current methodology.

Q Sure.

And one final question: You know, with this concern about increases in rates due to revenue erosion, one solution to that is beneficial electrification where particularly in the commercial sector we see electric forklifts, electric cranes, things like that.

Why has that not been a bigger focus in this process as a means of offsetting some of this -- the revenue erosion that's held back efficiency?

A (Witness Phillips) We're here to represent the DSM portion of the overall Integrated Resource Plan in developing the company's proposed case. So those items you mentioned are not incorporated as part of the overall DSM program planning approach which has been set forth by this Commission.

Q Even though there are some electrification measures in the DSM program, you wouldn't say that's your responsibility?

A (Witness Smith) The DSM -- the electrification measures that are in DSM are only built around incentivizing beyond whatever the base-level electric efficiency is to promote to go to a higher level. So it's not around shifting the energy or taking into account new energy sources. It's making sure that customers have an opportunity to get a more efficient option of whatever that, you know, measure is, regardless of whether it serves an electric resource or not.

MS. BROWN: Okay. Thank you.

MADAM CHAIR PRIDEMORE: Georgia Interfaith Power & Light?

BY MS. KYSOR:

Q Good afternoon. Good afternoon, panelists. Just a couple of questions. I'm referring to page 22 of your rebuttal testimony, and towards the bottom, lines 20 through 28. Let me know when you get there.

Are you there?

A Yes.

Q Great.

I'd like to discuss your characterization of Dr. Cox's testimony there. You paraphrase his testimony and I think argue that he's implying the entirety of the DSM portfolio is dispatchable.

Do I have that right?

A (Witness Phillips) That was our interpretation and that's what this specific part of our rebuttal testimony speaks to, yes.

Q Does it sound right to you that what Dr. Cox actually said on the stand was, specifically referring to demand response programs, he said they frequently and increasingly so are callable resources? Do you recall that?
A (Witness Valle) The demand response programs are dispatchable, and, therefore, they are callable, yes.
Q Okay. And you agree that the demand response programs are a part of your overall DSM portfolio; right?
A (Witness Phillips) Yes. When we think of DSM, we think of dispatchable resources, like demand response, and nondispatchable like the traditional energy efficiency measures: Attic insulation, more energy efficient appliances, and things like that.
Q And so the company could ramp up demand response programs and increase the amount of callable resources in the DSM portfolio; right?
A (Witness Phillips) The company has a number of demand response programs already available. They include different rate options, voltage reduction, as well as the thermostat DR program. And through the distributed energy resources pilot, the company is seeking to increase the DR options, pending approval of the DRC tariff as part of the distributed energy resources pilot.
MS. KYSOR: Thank you, gentlemen. That's all I

have.

MADAM CHAIR PRIDEMORE: Georgia Large Scale Solar Association, Advanced Power Alliance.

(No Response.)

MADAM CHAIR PRIDEMORE: Not present.

Georgia Solar Energy Industries Association.

MR. THOMASSON: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: Georgia Watch.

(No Response.)

MADAM CHAIR PRIDEMORE: Not present.

Interstate Gas Supply.

(No Response.)

MADAM CHAIR PRIDEMORE: Not present.

Restore Chattooga Gorge Coalition.

MR. S. JONES: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: Sierra Club.

MS. ARIZA: No questions.

MADAM CHAIR PRIDEMORE: Southern Alliance for Clean Energy and Southface Energy Institute.

MR. BAKER: Hello, again.

MADAM CHAIR PRIDEMORE: Hello, Mr. Baker.

MR. BAKER: Just a few questions, or a few more.

CROSS-EXAMINATION

BY MR. BAKER:

Q Good afternoon, Panel.

Your colleagues directed me to ask you these two questions that I had that they said you would be appropriate to answer.

Will Georgia Power and the Commission staff engage with members of the DSM working group on the substantive details related to competitive analysis of DSM at such times that stakeholders' input can be considered while the company is developing its modeling approach?

A (Witness Phillips) Yes, feedback will be considered and then certainly welcome as part of the DSM working group.

Q And that would be a collaborative discussion among all the -- I mean, with the company and with all the working group members?

A (Witness Phillips) Certainly. Feedback is always considered and welcome.

WITNESS VALLE: And as I mentioned in my summary to you, commissioners, the DSM working group will continue to work in the same manner as it has been in previous cycles. So we're not looking to change that relationship that we have with the -- with the parties involved in that group.

BY MR. BAKER:

Q Let me ask you a general question: What is your opinion of the DSM working group? Do they provide you with any kind of valuable insight or suggestions that maybe the company didn't consider or they did consider once they were made aware?

A (Witness Smith) Yeah, I think we could, you know, reference back to our original testimony where we cited that we did have several meetings with DS -- or with the DSM working group and other members of that group that led to direct input to several measures and components of our -- of our current DSM program offerings.

Q Thank you.

Can you confirm there will be a designated carve-out for the spending and savings levels for the manufactured homes energy-efficiency program, as described by the staff witnesses?

A (Witness Smith) Yes. As agreed to in the stipulation, there was, I believe, a three gigawatt hour a year carve-out associated for those manufactured home measures.

Q And turning to page 30 of your prefiled testimony, you state, quote, "The achievement of energy savings is not one of the three considerations the

Commission is directed to consider in setting the additional sum," close quote.

While the Commission is not directed to consider achievement of energy savings when setting the additional sum, do you agree the Commission does have the authority to consider?

A (Witness Valle) Sorry, Mr. Baker. Can you point me to the lines?

Q Page 30, line 6.

Do you have it?

A (Witness Valle) Yes.

Q Okay. Do you need me to repeat the question?

A (Witness Smith) Yeah, please do. Thank you.

Q All right. While the Commission is not directed to consider the achievement of energy savings when setting the additional sum, do you agree the Commission does have the authority to consider it?

A (Witness Smith) I think that would be up to a legal interpretation of what the statute is. But, obviously, we will abide by whatever the decision this Commission makes as it relates to additional sums.

Q All right. Thank you.

And let me ask you a general question: How do you define a pilot project?

COMMISSIONER MCDONALD: What?

BY MR. BAKER:

Q How do you define a pilot project?

A (Witness Smith) As it relates to -- as it relates to the DSM component of the pilot, it's looking at a new or emerging technology or opportunity to reach customers in a way that has not been done before in our area, and to see if it leads to a measure that could apply to future energy efficiency or demand response programs.

Q Okay. And how do you define a demonstration project?

A (Witness Smith) From a DSM perspective, I don't believe we've defined anything as a demonstration project.

Can you point me to where you're referencing that for us?

Q No, I can't. I was just asking if you -- I believe I thought there was a demonstration project included in one -- in the DSM cases.

So there is, to your knowledge, no demonstration?

A (Witness Smith) Currently, everything that we've done from a DSM perspective is a pilot --

Q Okay.

A -- not a demonstration project.

Q With regard to the water heater demand response pilot, you say, quote, "Pilots should be completed and properly evaluated before any decision is made to expand or certify them," close quote.

Isn't it possible to evaluate the performance of pilot programs while they remain underway, which would provide a smooth transition to program expansion, rather than the start/stop behavior your testimony seems to promote?

A (Witness Smith) So can you, first of all, point me to where you're referencing that from?

Q Page 23, line 5.

A (Witness Smith) Thank you.

So I don't think -- what I'm reading here does not say that pilots can't be evaluated as they're ongoing. It's saying before a final determination is made as to whether that should be included in a future DSM offering, a complete evaluation should occur.

Pilots do look at performance and how they're working during the pilot, but if you don't have a complete set of data -- in this case, a complete summer and winter and two shoulder seasons -- to evaluate the performance of the pilot we're talking about, then you can't give a complete finding and complete list of benefits or drawbacks that that measure would have as a full-on measure in a long-term program.

Q So you couldn't make a final decision whether to go forward with the program?

A (Witness Smith) You can't make a decision on the full economic value and the full performance of it without a full year.

Q Okay. Well, with regard to the 65 megawatt Mossy Branch battery storage facility, which is part of the 80 megawatt demonstration project approved in the 2019 IRP, even though it's not complete and won't be complete until next year, the company has indicated that it has already learned enough from the design process that the Commission should go ahead and authorize Georgia Power to build a 265 megawatt battery storage facility at McGrau Ford; isn't that correct?

A (Witness Smith) So I'm referring to demand side management pilots in this discussion. That's outside of my subject matter expertise.

MADAM CHAIR PRIDEMORE: Mr. Baker, this is a demand side management panel represented in the demand side management testimony in the section of the stipulation.

MR. BAKER: I -- yes, Madam Chairman. I was using that as an example. The Mossy Branch battery storage facility decision compared to --

MADAM CHAIR PRIDEMORE: That's a generation. That's two different things: Apples and oranges.

MR. BAKER: Well -- and the general concept is they're -- this project is not complete, but they're requesting --

MADAM CHAIR PRIDEMORE: Apples and oranges, two different -- these witnesses can't speak to battery storage, generation. They can speak to DSM.

MR. BAKER: I'm not asking them to speak to battery storage or the viability, but I'm asking them if they're aware that the company is moving forward with the demonstration.

MADAM CHAIR PRIDEMORE: You are. That's exactly what you're doing. You're asking them to speak to something, to field a question about something that they're not experts in. They're about demand side management.

BY MR. BAKER:

Q All right. Well, should the same standard of review be applied to the water heater demand response pilot that is being applied to the battery storage facility?

A (Witness Smith) Again, I'm not an expert on battery storage, and what I was referring to is a residential demand response pilot, not a battery storage project.

Q I guess, let me just say, hypothetically --

MADAM CHAIR PRIDEMORE: They don't know anything about battery storage.

MR. BAKER: I am -- I'm not going to talk about batteries. I'm talking about general --

BY MR. BAKER:

Q Hypothetically, if a project is not complete, how can the company make an evaluation in one case when they can't make an evaluation in another?

A (Witness Phillips) I may be able to help here, Mr. Baker, specific to how we calculate cost effectiveness of demand side options. When we calculate the cost effectiveness, we take into consideration the impact that energy efficiency or demand response measures have on the system. And as Witness Smith mentioned, we have to consider seasonality because the impact that a water heater might have on the system -- or excuse me -- the benefit that a water heater might have on the system could be different in the wintertime than it is in the summertime.

As an example, an energy efficiency measure that primarily provides value in the wintertime is likely not providing much value in a week like this when we are experiencing hundred-plus-degree days. And so we have to consider the full years' impact. We want to account for the seasonality, and that allows us to accurately calculate the avoided costs of that energy efficiency measure, which is a very important component of the overall cost effectiveness equation.

So that is -- that's how we evaluate it from a DSM perspective. I can't speak to the supply side evaluation.

Q Thank you.

At page 19, isn't the TRC test being waived for the direct control thermostat program?

A (Witness Phillips) That is a request of this Commission, yes, to waive the TRC -- or excuse me -- yeah, to waive the TRC requirement of the thermostat DR program.

Q Okay. And at page 20, you have some concerns with the manufactured home project and the fact that you're concerned that the manufactured home might be removed from the state of Georgia.

A (Witness Phillips) You mentioned page 20, which line are you referring to on page 20?

Q Line 5.

It says, "The replacement component of this program is not feasible to be implemented in Georgia Power service territory since there is no guarantee that

the upgraded manufactured home will remain within the company service territory or even in Georgia."

A (Witness Smith) That's one of the aspects of concern with that new home component of the offering.

Q Couldn't that problem be resolved in multiple ways by, one, having a penalty provision if the manufactured home is removed, by having a claw-back provision if the manufactured home is removed, or does having a written guarantee within the contract for that consumer that the home -- manufactured home will not be removed from the state? Wouldn't that take care of the issue?

A (Witness Smith) So if I understand your question, you're asking us can we claw back cost from a consumer on an incentive that was paid to a manufacturer; is that right?

Q Well, no.

Is there -- is there some way that you could provide some kind of a -- provide a disincentive to the consumer to remove that manufactured home from the state of Georgia and address the issue that you've raised here?

A (Witness Smith) So, again, and I apologize if I'm misunderstanding you, but what I'm hearing is put a penalty on the consumer when the incentive wasn't paid to that consumer.

MADAM CHAIR PRIDEMORE: Mr. Smith, you might have to explain to Mr. Baker how the program operates.

WITNESS SMITH: So the way that program -- thank you, Madam Chair.

The way that program was explained to us was that an incentive would be paid to the manufacturer of that manufactured home, not to the end user. And so an incentive would not be paid to the person that lives in that home or purchases it downstream. And if I understand what you're saying, it would be penalize that person if they move off of our lines, even though they never received the benefit of the incentive.

BY MR. BAKER:

Q Thank you for the clarification.

But isn't there some way that there could be an adjustment made to penalize maybe the manufacturer, if that were the case, to solve the problem of paying the benefit but having the trailer or the manufactured home removed from the state down the road at some time?

A (Witness Smith) In a cost-effective manner and in a program design that would be implementable, I would think it would probably be outside of the bounds of that. I'm not saying that it couldn't happen, but something that you could do in a cost-effective manner, I would doubt that.

MR. BAKER: Okay. Thank you, Panel. Thank you, Commissioners.

WITNESS PHILLIPS: Thank you.

MADAM CHAIR PRIDEMORE: Southern Renewable Energy Association. Oh, he's excused. He told me he was leaving.

Okay. Redirect?

MS. PRYOR: Just a few minor questions.

REDIRECT EXAMINATION

BY MR. PRYOR:

Q Panel, earlier Ms. Brown alluded to the DSM rider as the rate impact or the cost of the company's energy efficiency programs, and she compared that to the ECCR value or the fuel rate on a customer's bill.

Do you recall those questions?

A (Witness Phillips) Yes.

Q Isn't it true that the RIM test also captures the impact to base and fuel rates as well?

A (Witness Phillips) Yes, the RIM test calculates the lost revenues that are realized by reduction and kilowatt hour sales through energy efficiency measures.

MS. PRYOR: Thank you. No further questions.

MADAM CHAIR PRIDEMORE: Any other final

questions from Commissioners?

(No Response.)

MADAM CHAIR PRIDEMORE: Okay. Witnesses, you may be excused. That concludes the rebuttal testimony, rebuttal hearing. I first want to thank staff and the Georgia Power Company for working on the stipulated agreement. It is all-encompassing. Appreciate all of the effort that you guys have put forward with it.

Also want to thank those companies, those intervenors that have signed onto it.

Any other housekeeping matters?

(No Response.)

MADAM CHAIR PRIDEMORE: All right. Hearing none, we're adjourned.

(Hearing adjourned at 3:40 p.m.)

C E R T I F I C A T E

We, Kelley Nadotti, Debbie Eickhoff and Brenda P. Elwell, Certified Court Reporters, do hereby certify that the foregoing transcript is an accurate record to the best of our abilities of the proceedings in the above-entitled matter at the time and place therein set forth.

____
Kelley Marie Nadotti, RPR
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____
Debbie A. Eickhoff, RPR
CCR-5090-9084-2699-3664

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Brenda P. Elwell, RPR, CRR, B-2023

STATE OF GEORGIA

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

In Re:

Georgia Power Company's 2022 Integrated Resource Plan	)))	**Docket No. 44160**
In the Matter of: Georgia Power Company's 2022 Application for the Certification, Decertification, and Amended Demand Side Plan	))))	**Docket No. 44161**

Stipulation

The Georgia Public Service Commission (the "Commission") Public Interest Advocacy Staff ("PIA Staff"), Georgia Power Company ("Georgia Power" or the "Company") and the undersigned intervenors (collectively the "Stipulating Parties") agree to the following stipulation as a resolution of the above-styled proceedings to consider the Company's 2022 Integrated Resource Plan (the "2022 IRP") and Application for the Certification, Decertification, and Amended Demand Side Management Plan (the "2022 DSM Plan"). The Stipulation is intended to resolve all of the issues in these Dockets. The Stipulating Parties agree as follows:

Supply Side Plan

1. The 2022 IRP is approved as filed unless amended by this Stipulation.

2. Plant Wansley Units 1-2, Plant Wansley Unit 5A, and Plant Boulevard Unit 1 shall be decertified and retired by August 31, 2022.

3. Plant Scherer Unit 3, Plant Gaston Units 1-4, and Plant Gaston Unit A shall be decertified and retired by December 31, 2028.

4. The Company's Unit Retirement Study in this case supports the retirement of Bowen Units 1-2. PIA Staff analysis found that the retirement of Bowen Units 1-2 is a close call. Stipulating Parties agree that the decision to retire Bowen Units 1-2 and by when is a policy decision for the Commission. As such, provided that

retirement is contingent upon completion of the necessary transmission system improvements identified in Technical Appendix Volume I of the 2022 IRP, the Stipulating parties agree that it is appropriate for the Commission to determine as a matter of policy, when, between December 31, 2027 and December 31, 2035, Bowen Units 1-2 should be retired. The units may be retired separately or together. Should either or both units operate beyond December 31, 2027, all reasonable and prudent costs associated with their continued reliable operation will be recovered by the Company.

5. The Company's plan to install Effluent Limitation Guidelines ("ELG") controls for Plant Bowen Units 3-4 (and, subject to the retirement decision outlined in Paragraph 4, Plant Bowen Units 1-2), and Plant Scherer Units 1-2 is approved as part of the Company's Environmental Compliance Strategy ("ECS"), as discussed further in Paragraph 15.

6. The Stipulating Parties agree that the Commission should grant the certificate of public convenience and necessity for the long-term power purchase agreements ("PPA") for Plant Wansley Unit 7, Plant Dahlberg Units 2 & 6, Plant Harris Unit 2, Plant Dahlberg Units 1, 3 & 5, Plant Monroe Units 1-2, and Plant Dahlberg Units 8-10, as requested in this case.

7. The additional sum for the procurement of the long-term capacity PPAs approved in Paragraph 6 will be set at $3/kW-yr. Adoption of this additional sum is not precedent setting, and no Stipulating Party is foreclosed from proposing an alternative additional sum in a future capacity procurement.

8. The transmission projects necessary to accommodate the retirements approved in the 2022 IRP are approved. This approval includes the transmission projects (or their equivalent solutions) identified in the Selected Supporting Information section of Technical Appendix Volume 1.

9. The Company will develop and file an annual transmission update report with the status of each transmission project in the Company's Selected Supporting Information contained within Technical Appendix Volume 1 and the Unit Retirement Study contained within Technical Appendix Volume 2 of the 2022 IRP. The report will be filed on or before February 28 of each year and will include the schedule, status and budget for each active and future transmission project. For each transmission project, the Company will identify alternative solutions considered and the associated costs and benefits of the alternatives. In its 1st annual transmission update report, the Company should reconcile the

projects it plans to perform between the Selected Supporting information list, and the Unit Retirement Study list. The Company will continue to investigate and consider the use of emerging grid technologies as described in Technical Appendix Volume 3 of the 2022 IRP.

10. The Company is approved to proceed with the North Georgia Reliability & Resilience Action Plan ("North Georgia Reliability Plan") as defined in Chapter 12 of the 2022 IRP except for projects from the Utility Scale RFP being limited to projects sited in north Georgia. The Company will work with Commission Staff to develop a process that facilitates the development of renewable resources in north Georgia. The Company agrees to meet semi-annually with Commission Staff to provide updates regarding progress on the North Georgia Reliability Plan and the impacts of a future retirement of Plant Bowen Units 3-4. These meetings will include updates on strategic transmission projects developed by ITS Participants to allow for retirement of Plant Bowen Units 3-4 and the continued development of renewable resources in Georgia.

11. Staff reserves the right to challenge the timing of transmission capital investments during 2023 - 2025 in the upcoming 2022 rate case.

12. The Stipulating parties agree that the Company's request to develop, own, and operate 1,000 MW of energy storage system ("ESS") projects by 2030 is not approved in this IRP. While the Stipulating Parties acknowledge the potential value of ESS to the reliability of the electric system, the costs of ESS should be taken into account relative to any benefits provided.

13. The Company is provisionally authorized to develop, own, and operate the McGrau Ford Battery Facility (the "McGrau Ford Project"). The Company will be required to provide the final McGrau Ford Engineering Procurement and Construction ("EPC") agreement (or agreements if more than one) to the Commission prior to undertaking procurement for or construction of the McGrau Ford Project. Following the Company's provision of the EPC agreement to the Commission, the Commission will determine whether to proceed with the McGrau Ford Project and provide a deemed certified amount for the McGrau Ford Project. If the Company exceeds the deemed certified amount, the Company has the burden of showing that such costs were prudently incurred. The Company will also file quarterly construction monitoring reports from the date construction begins through the date of commercial operation.

14. In the absence of a Commission approved winter target reserve margin ("TRM"), and because resource additions are not anticipated during the 3-year IRP period using either the Staff's proposed 24.5% or the Company's proposed 26%, the Stipulating Parties agree that the Company will continue to use the System winter TRM of 26% for seasonal planning purposes until such time as a winter TRM is agreed to between PIA Staff and the Company and approved by the Commission. There is no requirement for the Commission to act upon the winter TRM request at this time. The Company may propose resource additions in the next IRP, if needed, to meet winter TRM, and the Commission can determine at that time the appropriate winter TRM and whether such additional capacity is needed. Use of the 26% winter TRM for planning purposes is not an endorsement by the Stipulating Parties of that TRM, and no Stipulating Party is foreclosed from proposing an alternative winter TRM in a future case.

15. The Company's ECS is approved as updated in the 2022 IRP. This includes specific approval of the updates to the Company's plans to address coal combustion residuals ("CCR") at the Company's ash ponds and landfills. Stipulating Parties acknowledge that projected CCR compliance costs have been reviewed in this case, that the Commission is not approving any costs, and that it is not necessary for the Commission to approve a specific budget for CCR compliance in this IRP proceeding. The Parties agree that the Company will seek recovery of such costs in its 2022 base rate case. PIA Staff reserves the right to challenge the Company's request for recovery in the 2022 base rate case, including, but not limited to, the amount to be recovered as reasonable and prudent, the period over which costs are recovered and the method by which they are recovered. The Company will continue to provide semi-annual reports to the Commission. The Company will also provide notice to the Commission within 30 days of any determination by the Environmental Protection Division that would alter the Company's current plan from closing certain ash ponds in place. Additionally, the Company will continue to file the ECS annually with the Commission no later than March 31st of each year.

16. Once the Company's CCR beneficial reuse RFP process has been completed, the Company will file a final report on the results of the RFP with the Commission. The report will include updates, if needed, to the Company's cost benefit analysis that provides economic justification of the Company's beneficial reuse plan.

17. The detailed cost information that supports the measures taken to comply with the existing government-imposed environmental mandates necessary for the Company to implement its ECS as presented in Technical Appendix Volume 2

and Environmental Compliance Cost Recovery ("ECCR") and CCR ARO tables in the Selected Supporting Information section of Technical Appendix Volume 1 of the 2022 IRP, as supplemented through data requests, have been reviewed in this proceeding and are acknowledged. Recovery of ECS plan costs will be determined by the Commission in a future rate case. PIA Staff reserves the right to challenge the Company's request for recovery of ECS plan costs in the 2022 base rate case, including, but not limited to, the amount to be recovered as reasonable and prudent, the period over which costs are recovered and the method by which they are recovered.

18. The Company will conduct an all-source Request For Proposal ("RFP") for capacity needed in the 2029 – 2031 period to address the expiration of capacity PPAs during 2029 – 2031 and any generation retirements. Specific RFP guidelines, including resource eligibility requirements, will be approved by the Commission in accordance with the Commission's RFP process.

19. The Company shall procure 2,100 MW alternating current ("AC") of new utility scale renewable resources, which are defined as projects greater than 6 MW AC in size. The Company will procure these resources for Commercial and Industrial customer subscriptions through the Clean and Renewable Energy Subscription ("CARES") Program through the carveout MW amounts as proposed in the Company's filing. Final program and tariff design for individual CARES carveouts will be finalized after the 2022 IRP through negotiations with members of the Commercial Group, members of the Georgia Association of Manufacturers, The Georgia Coalition of Local Governments, and Commission Staff. The Utility Scale procurement will take place through two separate RFPs. The first RFP is expected to be issued in 2023 and will target 1,050 MW of renewable resources with proposed commercial operation dates of 2026 or 2027. A second RFP is expected to be issued in 2025, seeking to procure the remaining MW needed to reach the 2,100 MW target procurement, with proposed commercial operation dates of 2028 or 2029. Any resources not fully subscribed through the CARES Program will serve all retail customers.

The following will be included in the fuel clause and recovered through the Fuel Cost Recovery Mechanism ("FCR"): (i) all revenues collected through the CARES Program, with the exception of the additional sum as described in Paragraph 23, and (ii) all appropriate costs that are not recovered elsewhere by the Company and are incurred in connection with the procurement of the aforementioned resources for subscription in the CARES Program. CARES Program costs and revenues which are to be included in FCR include but are not limited to the following: (i) the costs to implement and administer the CARES Program, (ii) the bid fees collected in connection with the CARES Program, the fees collected from subscribing customers, and (iii) the PPA that are executed to supply the CARES Program, including any payments for PPAs made by participants.

20. The Company's evaluation and selection of renewable resources based on the best cost provided to customers is approved for future renewable procurements. The Company will work with PIA Staff and the Independent Evaluator ("IE") to determine the exact criteria and methods of evaluating, ranking, and selecting bids through the aforementioned best cost methodology as part of the Commission-approved RFP process.

21. For future Utility Scale renewable RFPs, all renewable projects, both with and without storage devices, will be required to be operated on Automatic Generation Control ("AGC"), and the Company will consider new use cases that flexibly utilize the coupled energy storage devices with AGC control. The Company and Staff shall determine the appropriate methodology to value such resources before the next Utility Scale renewable RFP is released.

22. The Company shall issue an RFP to procure energy from up to 200 MW AC of distributed generation solar resources ("DG"), which are defined as being greater than 250 kW but not more than 6 MW AC in size. It will do so through two solicitation periods, each seeking 100 MW AC of DG solar resources. The first solicitation is expected to occur in 2023 with proposed commercial operation dates of 2024. The second solicitation is expected to occur in 2024 with a proposed commercial operation dates of 2025. The projects will be procured using the Company's best cost procurement approach which will be agreed upon by the Company and Staff and approved by the Commission during the RFP process. Contract terms for resulting DG projects will be for up to 35 years. DG projects must interconnect to Georgia Power's distribution system. Bid and winners' fees will be set to recover the total cost of procurement for the RFP solicitations. All revenues collected, and all appropriate costs not recovered elsewhere by the Company, which are incurred in connection with the procurement of the aforementioned DG resources shall be included in the fuel clause and recovered through the FCR.

23. The additional sum for both the utility scale resources procured pursuant to Paragraph 19 above and the DG resources in Paragraph 22 shall be set at a levelized additional sum of $4.00/kW-yr. Adoption of this additional sum is not precedent setting, and no Stipulating Party is foreclosed from proposing an alternative additional sum in a future renewable procurement.

24. The Hosting Capacity Tool is approved and will be modified as follows. The Hosting Capacity Tool will be made available year-round pursuant to a registration process that requires the signing of a confidentiality and nondisclosure agreement. The Company will work to update the Hosting Capacity Tool semi-annually, but initial efforts will be focused on an annual update for the Company's more than 2,300 feeders. The hosting capacity analysis shall also reflect the available solar capacity based on Minimum Daytime Loading or Coincident Peak limitations at the breaker, but is not intended to be a replacement for the Company's required interconnection study process. Administrative costs associated with the Hosting Capacity Tool will be recovered through the FCR.

25. The Company and Staff will initiate a review of Georgia Power's DG interconnection process prior to the next DG RFP to consider modifications and to establish a distribution interconnection cost matrix.

26. The Existing Resource Retail REC Retirement ("R3") Program is approved. The Company agrees to file quarterly participation reports that provide the amount of MW and the number of customers that have subscribed to the R3 program.

27. The Company's Community Solar Program proposed in the 2022 IRP is approved except for the Company's requests to increase the residential block charge to $27.99 and to set the commercial option at $29.99/month, which will be considered in the 2022 Rate Case. This approval includes the Income-Qualified Community Solar Pilot. The Company agrees to file quarterly participation reports that provide the number of customers and subscription blocks that have been subscribed to for each portion of the Community Solar program.

28. The Company's Flex REC Program and modification to the Simple Solar Program proposed in the 2022 IRP are approved except for revisions to the rates for this program, which will be considered in the Company's 2022 Rate Case. The Company agrees to file with the Commission, for informational purposes, the negotiated contracts for the Economic Development Flex REC option once they are executed.

29. The Renewable Cost Benefit Framework ("RCB") and the Renewable Integration Study ("RIS") filed in this case are approved for future renewable procurements with the three following modifications. First, the Stipulating Parties agree to use the incremental renewable integration costs approach when determining the renewable integration costs for future renewable procurements until a future study

is completed and approved. This assumption will be $1.93/MWh for solar resources up to the 2,300 MW of new renewables approved in this IRP. Staff and the Company will meet after the 2022 IRP concludes to address the other methodological differences discussed in Section 4 of Staff's direct testimony and then file a report, including any proposed methodology changes by either party resulting from the discussions, with the Commission for approval by June 30, 2023. In addition, the Company and Staff will discuss Staff's suggestion to modify the Deferred Generation Capacity Cost component to use the economic carrying costs ("ECC") of a combined cycle unit instead of a combustion turbine. Second, for IRP-approved procurements for which RECs are conveyed, the Stipulating Parties agree to include a REC component within the RCB Framework. Staff and the Company will meet after the 2022 IRP concludes to determine how to appropriately value the REC component and then bring the method to the Commission for approval. Third, the Stipulating Parties also agree to use the effective load carrying capability ("ELCC") method when determining capacity value for procurement activities. The Stipulating Parties agree that resolution of this issue does not limit the positions that either Party can take regarding the RCB and RIS costs in a future proceeding where modifications to the RCB and RIS may be considered.

30. In the next IRP, and any upcoming RFPs issued before the next IRP, the Company agrees to use the ELCC methodology to determine the renewable resource capacity values.

31. The Stipulating Parties agree that the Blocks 2-4 and Blocks 5&6 wholesale block capacity offer should be rejected by the Commission. The offer by the Company, and the rejection by the Commission fulfills the Company's requirements under Docket No. 26550 to offer this capacity to the retail jurisdiction. The Company may, at its own discretion, offer such capacity within the wholesale market or to the retail jurisdiction in a future capacity solicitation or through other permissible avenues. In addition, the Commission should deem the Company's obligations to make any wholesale offer under Docket No. 26550 consisting of Plant Gaston Units 1-4 and A and Plant Scherer Unit 3 satisfied, thereby releasing the Company from any further requirement to offer wholesale capacity from these units to the retail jurisdiction prior to any remarketing of that capacity.

32. The Stipulating Parties agree to approve the modernization of Plant Sinclair and Plant Burton. The proposal to include Plant North Highlands in the Company's hydro-electric modernization plan is not approved at this time. Plant Sinclair and Plant Burton shall be added to the Company's semi-annual reporting on its hydro

modernization efforts. All future hydro modernization requests will include a cost-benefit analysis and economic comparison of the alternatives to modernization. The Company will provide such an analysis for Plant Burton in its 2025 IRP filing.

33. The DER Customer Program proposed to be implemented through the Demand Response Credit Tariff ("DRC-1") and the Resilience Asset Service Tariff ("RAST-1") will be approved on a pilot basis with an overall cap of 250 MW. The tariffs and associated contract terms and conditions shall be designed in a manner that will eliminate, to the extent reasonably possible, any potential that non-participating customers will be harmed. Within 4 months following the issuance of the Commission's Order approving this Stipulation, the Company will collaborate with the Commercial Group and Staff on the development of these elements in the DER pilot program tariffs. Following this collaboration, the Company shall file the DRC-1 and RAST-1 tariffs for Commission approval. The Stipulating Parties preserve their right to argue for modifications to the tariffs when they are filed for approval.

34. The DER local reliability and constraints pilot projects at Mansfield, Savannah, Moreland Way and Lake Sinclair are approved. The Company shall file semi-annual update reports for the first five years of the pilot projects.

35. The capital and O&M costs for the Tall Wind demonstration project (but not yet the recovery of such costs), as set out in the Selected Supporting Information section of Technical Appendix Volume 1, are approved. The Company agrees to notice the Commission should it determine that the budget for the Tall Wind project will exceed the budgeted amount presented in the 2022 IRP. The Company shall file semi-annual update reports through the life of the demonstration project.

36. The integrated Hydrogen Microgrid pilot project as set out in Selected Supporting Information section of Technical Appendix Volume 1 is approved. The Company shall file quarterly update reports through the life of the pilot project.

37. The remaining net book values of Plant Wansley Units 1-2, Plant Wansley Unit 5A, and Plant Boulevard Unit 1 shall be reclassified as regulatory assets and the Company shall provide for amortization expense at a rate equal to the unit's depreciation rate approved in the Company's 2019 base rate case. The timing of recovery of the remaining balances of these regulatory assets as of December 31, 2022, will be deferred for consideration in the Company's 2022 base rate case.

The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the recovery mechanism and appropriate period in which the costs should be recovered. Parties may argue their respective positions on that issue in the 2022 base rate case.

Any unusable materials and supplies inventory balance remaining at the date of each unit retirement shall be reclassified as a regulatory asset and the timing of recovery deferred for consideration in the Company's 2022 base rate case. The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the recovery mechanism and appropriate period in which the costs should be recovered if applicable. Parties may argue their respective positions on that issue in the 2022 base rate case.

38. The remaining units that are decertified and retired pursuant to the final order issued in this IRP are projected to retire after 2025. As such, the Stipulating Parties have agreed for purposes of settling this case that the remaining net book values and unusable materials and supplies inventory balances, if any, for those generating units retiring after 2025 approved in this case will be reclassified to regulatory asset accounts as of the units' retirement dates. The timing of recovery for the regulatory assets, if a balance remains, shall be decided in a future base rate case.

39. Following each unit's dismantlement, any over or under recovered cost of removal balances shall be reviewed in a future base rate case.

40. The capital and O&M costs the Company will incur for the subsequent license review for Plant Hatch Units 1-2 (but not yet the recovery of such costs) are approved as presented in this IRP.

41. The Company agrees to update its Residential Consumer Survey to collect more recent information regarding the end-use market saturation and incorporate as appropriate in the 2025 IRP.

42. The Company agrees to file with the 2025 IRP a forecast scenario of Georgia Power's Peak Demand and Energy forecast using weather normal data for the most recent 20 years.

43. In conjunction with the ongoing level of review and analysis required by this agreement, Georgia Power will agree to pay for any reasonably necessary specialized assistance to PIA Staff in an amount not to exceed $500,000 annually.

This amount paid by Georgia Power under this Paragraph shall be deemed as a necessary cost of providing service and the Company shall be entitled to recover the full amount of any costs charged to the utility.

Demand Side Plan

1. The Company's DSM Certification is approved as filed with the following adjustments proposed by PIA Staff and agreed to by the Company.

2. The Company will include an additional sensitivity in its 2025 IRP development and resource optimization process. In this additional sensitivity case, DSM resources, including demand response and energy efficiency, will be allowed to compete head-to-head with supply-side options in the Company's IRP model as a selectable resource. This new sensitivity will replace the Aggressive Case scenario in the DSM Program Planning Process. The Commission will authorize the Company to recover the additional costs required to complete this new sensitivity through the DSM rider after review and approval by Commission Staff. To implement this change:

    a. Step 8 in the DSM Program Planning Process will be revised to state: "The Company will also produce an additional sensitivity in its 2025 IRP development and resource optimization process, where DSM is allowed to compete head-to-head with supply-side options in the Company's IRP model as a selectable resource."

    b. Step 9 in the DSM Program Planning Process will be revised to state: "The Company will use the difference in costs between the base case and the Proposed DSM change case configuration to determine the avoided generation cost impact of the DSM measures in the Proposed DSM change case. As the final step, the cost effectiveness tests mentioned in item 6 (above) will be calculated based on the inputs and adjustments from the system tools. Revenue impacts will be based on current rates and escalations based on the Company's financial projections adjusted for the DSM cost impacts. The avoided generation costs from the system tools and the avoided Transmission and Distribution ("T&D") revenue requirements as estimated by PRICEM will be used to calculate the benefits of the RIM, TRC and Program Administrator test for the Proposed DSM change case. The projected deadline for including new programs in the system planning process is October 1, 2024.

3. The Demand Side Management Working Group ("DSMWG") will continue in its current form and be involved in the development of future DSM programs in the same manner it has operated in past IRP cycles.

4. The Commission will approve the Company's request for decertification of the Residential Power Credit and Commercial Midstream Programs, approval of the certification of the HopeWorks Program, approval of the Company's waiver request for Commission Rule 515-3-4-.04(4)(a)3 for the Thermostat Demand Response Program, and approval of the amended certificates for the Residential Behavioral, Residential Home Energy Improvement Program ("HEIP"), Residential Refrigerator Recycling, Residential Specialty Lighting, Residential Home Energy Efficiency Assistance, Commercial Custom, Commercial Prescriptive, Commercial Small Commercial Direct Install, and Commercial Behavioral Programs.

5. The Company will pause the Commercial Behavioral Program, pending decertification, if the upcoming 2024 Evaluation, Measurement, and Verification ("EM&V") does not show the program to be cost effective.

6. The Residential Investment to Save Energy ("RISE") pilot will continue for the 2023-2025 program cycle in its current form.

7. The Automated Benchmarking Tool ("ABT") will continue for the 2023-2025 program cycle as approved in the 2019 IRP at a preapproved cost of $600,000.

8. The HEIP will be expanded to include the proposed Manufactured Homes Program, with the exception of "whole home replacement" measures, as described in the PIA Staff's testimony.

9. The DSM energy savings targets will be adjusted using the Applied Energy Group ("AEG") tool used by the Company in this case in order to add the savings from the additions in Paragraph 8 to the HEIP.

10. The DSM program budget will include a reduction of non-incentive costs for certified programs by a total of $4 million over the three-year program cycle.

11. The Commercial Custom Program will include a per building cap of $75,000 in its final program plan.

12. The Education Initiative-Learning Power budget will be $4 million annually for 2023-2025.

13. The annual Residential and Commercial Energy Efficiency Consumer Awareness budgets will be $4.5 million and $1.1 million, respectively, for the 2023-2025 program cycle.

14. The DSM pilot budget will be $3 million per year, to be split evenly between Residential and Commercial classes. The Company will seek Staff's input regarding any proposed pilots before they are implemented and throughout the course of the pilot.

15. The current methodology approved for the DSM additional sum mechanism will continue with an increase to 9.5% of shared savings, and the Company's additional sum will continue to be based on net energy savings rather than gross energy savings.

16. Once the Company selects program implementers and program plans are developed, these plans will be provided to PIA Staff for review and input prior to implementation of the corresponding programs. The Company should provide PIA Staff with at least 15 days for review of the Final Program Plans.

17. The current DSM true-up process will continue, including not allowing the rollover of unspent annual budget dollars or unrealized savings targets.

18. The three-year program EM&V cycle will continue from 2023 to 2025.

19. As set forth in Staff's testimony, the 2021 and 2018 EM&V results will be used as recommended by the independent program evaluators.

20. For commercial lighting hours of use ("HOU"), the Company will continue to use the AEG design tool's results for energy savings for the current cycle. The Company agrees to do a commercial lighting HOU study in the 2024 EM&V process and will apply those results as determined by the evaluator for future programs.

21. The Company will evaluate income-qualified savings in a manner consistent with the remainder of the Residential sector to confirm whether this NTG assumption is appropriate. The Company will work with Staff to determine whether values

derived from the EM& V results should be used in future income qualified program planning.

22. Staff recommends the continuation of the current policy to implement the EM&V results in the first year of the next IRP cycle.

23. The upcoming EM&V shall include a new in-situ metering study for the Refrigerator Recycling Program. The costs of the study will be recovered from the DSM rider.

24. The current Commission policy that requires the Company to provide detailed evaluation plans for each of the approved DSM programs within 90 days of the selection of the Program Implementers for each of the certified programs will continue. However, Staff will work with the Company to extend the 90 days on an as-needed basis as it has in prior IRP cycles.

Agreed to this 10th day of June 2022.

Preston Thomas

On Behalf of the Georgia Public Service Commission
Public Interest Advocacy Staff

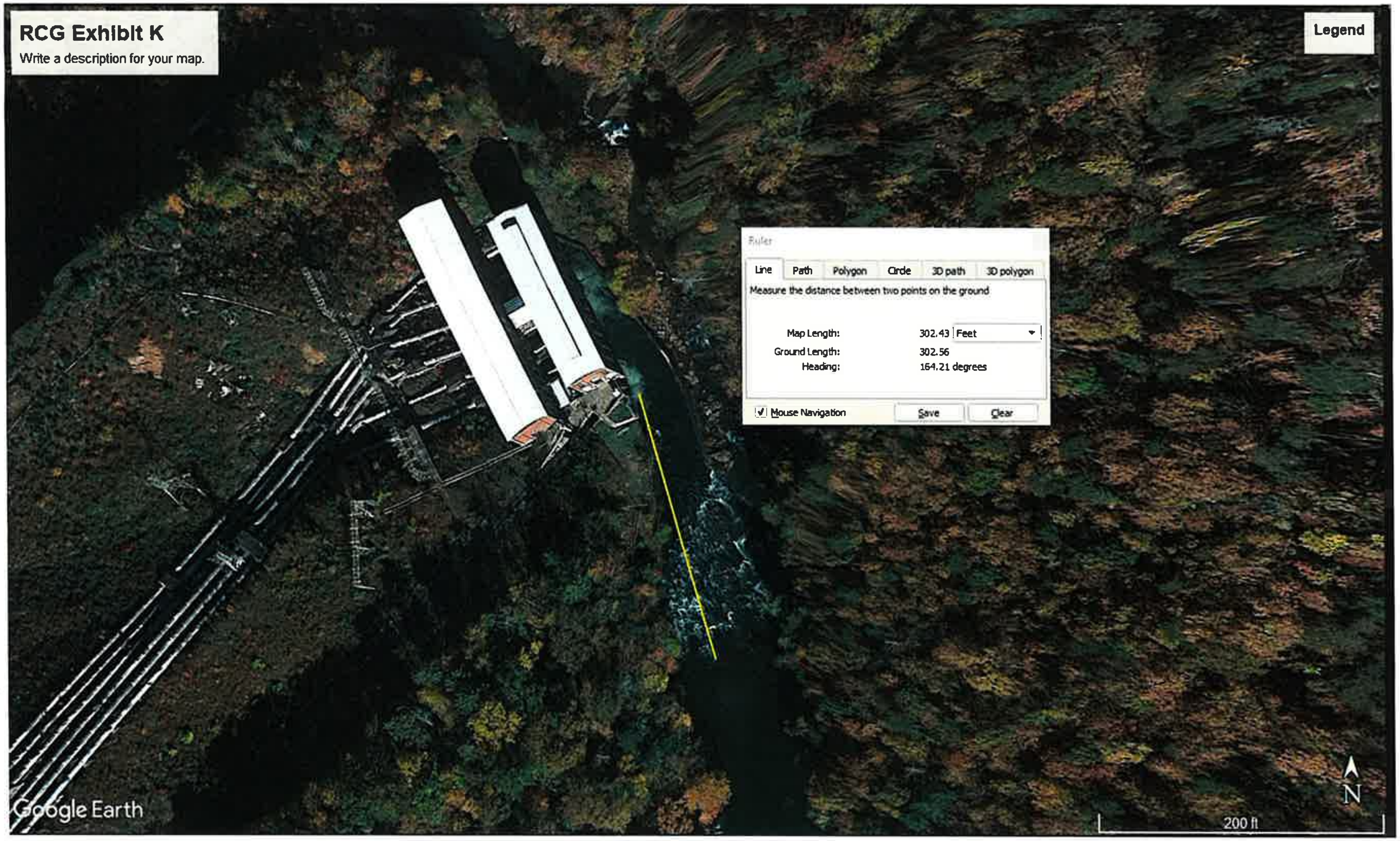
Brandon F. Marzo

On Behalf of Georgia Power Company

Alan R. Jenkins
On Behalf of the Commercial Group

Charles B. Jones, III

Charles B. Jones, III
On Behalf of the Georgia Association of Manufacturers



RCG Exhibit K