BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:		
GEORGIA POWER COMPANY'S	**)**	**DOCKET NO. 44160**
2022 INTEGRATED RESOURCE PLAN	**)**	
GEORGIA POWER COMPANY'S	**)**	**DOCKET NO. 44161**
APPLICATION FOR THE CERTIFICATION,	**)**	
DECERTIFICATION, AND AMENDED	**)**	
DEMAND-SIDE MANAGEMENT PLAN	**)**	

DIRECT TESTIMONY AND EXHIBITS

OF
JOHN W. CHILES

ON BEHALF OF THE

GEORGIA PUBLIC SERVICE COMMISSION
PUBLIC INTEREST ADVOCACY STAFF

May 6, 2022

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INTRODUCTION

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

A. My name is John W. Chiles. I am a Principal at GDS Associates, Inc. My business address is 1850 Parkway Place, Suite 800, Marietta, Georgia 30067.

Q. HAVE YOU INCLUDED SUMMARIES OF YOUR EXPERIENCE AND QUALIFICATIONS IN THIS TESTIMONY?

A. Yes. My resume is included herein as Exhibit JWC-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am testifying on behalf of the Public Interest Advocacy Staff ("Staff") of the Georgia Public Service Commission ("Commission"). The purpose of my testimony is to respond to certain elements of Georgia Power Company's ("Company" or "Georgia Power") 2022 Integrated Resource Plan ("IRP") filing. I will address issues pertaining to the Company's transmission planning processes including the evaluation of the Company's Ten-Year Plan.

SUMMARY OF RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. First, I have reviewed the Company's Ten-Year Transmission Plan and agree with the results of the projects in that they meet NERC TPL requirements. Second, I support the recommendations of the Company regarding the proposed retirement of Plant Wansley Units 1-2 and Unit 5A, Plant Boulevard Unit 1, Plant Gaston Units 1-4 and Unit A, Plant Bowen Units 1-2 and Plant Scherer Units 1-3. I am recommending that the Company continue the review of the required transmission facilities associated with the retirement of Plant Bowen

Units 3-4 prior to their planned retirement in 2035. Third, I am supportive of additional reporting requirements associated with the proposed Energy Storage Systems to ensure that the Company is achieving their goals with assessing ESS technologies. Lastly, I am recommending that the Commission develop a Commission-led collaborative long-term transmission planning process to identify the needs and solutions for North Georgia in light of retirement challenges, unknown renewable generation siting needs and ESS requirements prior to the 2025 Integrated Resource Plan.

EVALUATION OF THE COMPANY'S TRANSMISSION PLANNING PROCESS

Q. HAS THE COMPANY PROVIDED A DESCRIPTION OF THEIR TRANSMISSION PLANNING PROCESS?

A. Yes, the Company has provided a description of their planning process in Section A of Trade Secret Volume 3 of the 2022 Integrated Resource Plan.

Q. WHAT TYPES OF MODELS DOES THE COMPANY USE WHEN PERFORMING THE TRANSMISSION PLANNING FUNCTION?

A. The Company uses both load flow models and stability models.

Q. WHAT IS A POWER FLOW OR LOAD FLOW MODEL?

A. A load flow model is a model of the electric power system. It contains representations of substations, transmission lines, transformers, generators, loads, and other power system components such as capacitor banks. The load flow model is used to model a system condition, such a high demand period.

Q. DOES THE COMPANY DEVELOP JUST ONE SET OF LOAD FLOW MODELS FOR ALL STUDIES?

A. No. The Company develops a base case load flow model that incorporates the existing system plus all planned transmission additions up to a specified date. These include a current year or "Year 0" case and a set of cases for the next ten years. Additionally, there are multiple sets of base case load flow models that reflect various phases of the Integrated Transmission System (ITS) coordinated planning process. The Company creates a Version 1 set of models that reflect the input of data from all ITS Participants and include planned transmission additions. There is also an error checking stage that the models undergo to make sure the information is verified by multiple parties. The Company also creates a Version 2 set of models in which some future transmission additions are "stripped" from the model in order to create the final base case models.

Q. WHAT FUTURE TRANSMISSION PROJECTS ARE LEFT IN THE MODEL FOR THE VERSION 2 BASE CASES?

A. The Company has stated that there are three reasons why a future project is kept in the Version 2 models. They are: (1) if the project is far enough along in the engineering and construction process, (2) if the projects are tied to contracted obligations for specific years, or (3) if the projects are tied to certain assumptions, such as improvements associated with new generation additions. These Version 2 cases represent the completed plan.

Q. IN TERMS OF ASSESSING THE IMPACT ON THE TRANSMISSION SYSTEM OF THE COMPANY'S PLANS FOR THE DECERTIFICATION AND

RETIREMENT OF GENERATION, IS IT THE VERSION 2 CASES THAT FORM THE BASIS FOR THOSE DECISIONS?

A. That is my understanding based on the Company's filing.

Q. AT WHAT POINT IN THE TRANSMISSION PLANNING PROCESS DOES THE EFFECT OF CHANGES TO THE GENERATION EXPANSION PLAN GET INCLUDED?

A. It appears that changes to the generation expansion plan are considered in the Project Evaluation phase of the planning cycle (Technical Volume 3, Section A.6.d). Up to this point, the set of solutions in the base cases remain constant. As solutions are evaluated, the base case assumptions can vary and this includes the generation expansion plan assumptions.

Q. IN THE DEVELOPMENT OF THE POWER FLOW MODELS FOR THE TEN-YEAR TRANSMISSION PLAN, DID THE COMPANY INCLUDE ANY PLANNED GENERATION RETIREMENTS IN THE VERSION 1 OR VERSION 2 MODELS?

A. Yes. The planned retirements of Plant Wansley Units 1-2 and Plant Boulevard Unit 1 were included in the power flow base models.

Q. DO THE TRANSMISSION PLANNERS GET TO MAKE DECISIONS REGARDING THE TIMING, SIZE AND LOCATION OF FUTURE GENERATION PLANTS?

A. According to Technical Volume 3, Section A.6b, it is a "management decision" regarding the timing, size and location of future generation plans.

Q. WHY WERE SOME RETIREMENTS INCLUDED IN THE MODELS BEFORE THEIR RETIREMENT WAS APPROVED BY THE COMMISSION?

A. That is difficult to say.

Q. IS THE TEN-YEAR TRANSMISSION PLAN THE ONLY STUDY PERFORMED BY THE COMPANY TO ASSESS SYSTEM PERFORMANCE?

A. No. The Company has several study efforts to address various needs on the transmission system. These include Operating Studies, Loss Studies, System Interface Studies, and Optimal Generation Siting Studies.

Q. DOES THE COMPANY USE THE SAME ASSUMPTIONS FOR EACH STUDY CONSISTENT WITH THE VERSION 1 AND VERSION 2 BASE CASE POWER FLOW MODELS FROM THE TEN-YEAR TRANSMISSION PLAN?

A. No, they do not. The near-term Operating Studies look at system conditions for the next season (e.g., Summer 2022) to identify any unusual conditions that could arise based on short-term load forecast changes, planned transmission and generation outages and new generation changes. These models use different load and transmission topology assumptions from the Ten-Year Plan. The System Interface Studies look at the impact of regional flows from neighboring systems and how those flows impact the ability of the Southern Company System to import or export electricity. These models include more detailed representations of the neighboring systems, and also include base flows across the various interfaces from long-term firm transmission commitments. Reductions in available capacity are made to capture reliability margins associated with regional power delivery, such as Transmission Reliability Margin and Capacity Benefit Margin. The Optimal

Generation Siting Study uses a separate power flow model to look at the high-voltage busses on the Company transmission system that could potentially accommodate additions of new generation.

Q. DOES THE OPTIMAL GENERATION SITING STUDY INCLUDE THE IMPACT OF PROPOSED RETIREMENTS IN THE ANALYSIS?

A. The Company references that each year there are changes to load, generation and transmission that could impact the results but the Company did not reference specific assumptions regarding retirements.

Q. HOW OFTEN DOES THE COMPANY PERFORM THIS ANALYSIS?

A. The Company does not provide a specific timetable for performance of this study, but does mention that it will be performed periodically going forward.

Q. DID THE COMPANY EVALUATE ALL POTENTIAL BUSSES IN THE GEORGIA POWER SYSTEM FOR OPTIMAL SITING?

A. Only busses located in North Georgia were published in the latest study. In STF-GDS-4-3, the Company explained that North Georgia includes those counties located north of Interstate 20 and those counties bisected by Interstate 20. Other sites were removed from consideration due to the concentration of solar development in South Georgia and the increases in south-to-north flows on the system.

Q. WOULD THE COMPANY BENEFIT FROM PERFOMING THIS TYPE OF ANALYSIS ON AN ANNUAL BASIS?

A. Absolutely. The Company's goals related to increasing renewable generation penetration in the State necessitate having a transmission system that can accommodate those goals. Developers benefit from knowing where to target the system to maximize use of the transmission system and where to minimize the need for costly upgrades that may make their projects uneconomic. The consumers would benefit from having lower costs with an optimized solution that neither overbuilds generation in undesirable locations or in constructing transmission infrastructure that does not achieve reliability and resilience goals. This type of transparency in planning would facilitate better decision-making instead of the three year look the Commission gets in the IRP.

THE RENEWABLE RFP AND TRANSMISSION

Q. THE COMPANY HAS DISCUSSED A FUTURE RENEWABLE RFP AND THE NEED FOR GENERATION IN NORTH GEORGIA TO ADDRESS RETIREMENT CONCERNS AND THE GENERATION IMBALANCE BETWEEN RENEWABLE RESOURCES IN SOUTH GEORGIA AND HIGHER LOADS IN NORTH GEORGIA. HOW SHOULD THE COMPANY CONSIDER THE EFFECT OF SITING DECISIONS FOR NEW RENEWABLE CAPACITY IN THE RENEWABLE RFP IN THEIR PLANNING PROCESS?

A. There are two approaches that could be considered. The first approach, which appears to be the Company's preference, is to encourage projects in North Georgia in the RFP. The role of the transmission planner in this generation-centric approach is to designate preferred sites or regions and then to build appropriate infrastructure to support the expected generation once the total portfolio is known. The second is to develop the transmission infrastructure first and then encourage developers to take advantage of the backbone transmission expansion by siting generation in those locations. With all of the uncertainty surrounding the generation portfolio in North Georgia with proposed retirements and new generation, development of the backbone system may be the preferred direction for the Company to consider. I recommend that Commission develop a collaborative transmission planning process which has Commission oversight and includes all of the ITS Participants, the Staff and the Company to wrestle with this issue and come up with a comprehensive plan that considers the regional needs for a reliable, resilient and economic grid to support the Company's transition to a clean energy future.

Q. DO YOU SUPPORT THE IDEA OF THE COMPANY DESIGNATING NORTH GEORGIA AS THE ONLY PLACES FOR NEW RENEWABLE GENERATION?

A. I support the Company running their Renewable RFP to consider capacity throughout the state, but maybe consider either a reduced value of capacity or a transmission cost adder to proposals not sited in the North Georgia region.

Q. HAS THE COMPANY PERFORMED ANY ANALYSIS OF POTENTIAL GENERATION SITES FOR THE RENEWABLE RFP?

A. To my knowledge, the Company has not provided any transmission studies related to the requirements of the Renewable RFP.

Q. WOULD YOU SUPPORT THE COMAPANY PERFORMING AN OPTIMUM GENERATING SITING STUDY AND MAKING THOSE RESULTS AVAILABLE TO BIDDERS INTO THE RENEWABLE RFP?

A. Yes, I would support the Company letting developers know locations that are the most desirable from a transmission perspective prior to bid submittal.

<u>THE NORTH GEORGIA RELIABILITY AND RESILIENCE PROJECT</u>

Q. IS THE COMPANY PROPOSING A NORTH GEORGIA RELIABILITY AND RESILIENCE PROJECT IN THIS IRP?

A. Chapter 12 of the IRP Main Document discusses the concept of the North Georgia Reliability and Resilience Action Plan, but the Company is not proposing a specific set of facilities that would make up a solution set.

Q. WHAT DRIVERS WILL HAVE THE LARGEST IMPACT ON THE TRANSMISSION SOLUTIONS THAT WILL MAKE UP THE NORTH GEORGIA RELIABILITY AND RESILIENCE ACTION PLAN?

A. The main drivers for serving load in North Georgia is the retirement of Plant Bowen Units 1-4, the high concentration of renewable resources in South Georgia and the location of new generation that may be selected in the Renewable RFP.

Q. HOW WILL THE NORTH GEORGIA RELIABILITY AND RESILIENCE PROJECT IMPACT THE DECISIONS SURROUNDING FUTURE GENERATION RETIREMENTS AND THE SITING OF GENERATION FOR THE RENEWABLE RFP?

A. The construction of transmission infrastructure to facilitate the delivery of existing renewable resources from South Georgia to a generation-deficient North Georgia load sink, due to the planned retirement of Plant Bowen Units 1-4, is critical to the ability to serve the Company's load requirements. Not already having a transmission expansion plan that is designed to facilitate new generation to feed North Georgia is a serious problem that requires rapid decisions. The failure of the Company to have a long-term strategic plan in place for the loss of Bowen generation is a flaw in the Company's planning process and something that should have been addressed in a Commission-directed, transparent process long before the 2022 Integrated Resource Plan. Many organizations conduct long-term planning assessments beyond the ten-year horizon, and the Company and Commission would benefit from such a collaborative long-term transmission planning process which includes Staff, consultants, and ITS Participants.

Q. HAS THE COMPANY PERFORMED ANY STUDIES RELATED TO THE NORTH GEORGIA RELIABILITY AND RESILIENCE PROJECT?

A. To date, the Company has not performed any specific studies although there appear to be initial discussions with the ITS Participants regarding this topic based on the Company's comments in the IRP Main Document in Section 12.1 ("To date, strategic projects remain under development with ITS Participants.").

Q. HAS THE COMPANY IDENTIFIED ANY SPECIFIC SOLUTIONS AT THIS TIME?

A. The Company has not identified any solutions at this time.

Q. SHOULD THE COMMISSION STAFF HAVE ANY INPUT INTO THE PROJECTS THAT WILL MAKE UP THE NORTH GEORGIA RELIABILITY AND RESILIENCE PROJECT?

A. The significant changes in the Company's generation mix and retirement/siting strategy requires a long-term view and will likely require much analysis. Additionally, with potentially large-scale and potentially expensive expansion of the transmission system, the need for the Commission to fully understand the options, scope, costs and rate treatment for future facilities will benefit Georgia consumers. Staff needs to understand the process and the results. One of the best ways to do that is to be walking alongside the Company and impacted stakeholders as the plan is developed. If the Company only identifies projects for approval in the 2025 IRP, there will not be enough time to consider alternatives. This is already the problem with the evaluation of the retirement of Plant Bowen Units 3-4 in the 2022 IRP. The lead-time lead time for traditional transmission solutions, and the apparent failure to not consider alternative solutions, limit the Commission's ability to approve anything other than the Company's proposed solution.

Q. IF THERE WERE MORE COORDINATION BETWEEN THE COMPANY'S VARIED STUDY EFFORTS AND IMPACTED STAKEHOLDERS, DO YOU BELIEVE THIS WOULD RESULT IN A MORE ROBUST PLANNING PROCESS?

A. Yes, I do believe that more coordination and communication with staff and stakeholders throughout the transmission expansion planning process would produce a plan that has greater buy-in from regulatory bodies and the developer community.

Q. HAVE YOU SEEN OTHER STATES WHERE THERE IS A JOINT TRANSMISSION PLAN THAT IS PRODUCED THROUGH A STAKEHOLDER PROCESS, THAT IS NOT PART OF A REGIONAL TRANSMISSION ORGANIZATION?

A. Yes, there are statewide transmission planning processes that are performed in both North Carolina and Arizona, where the Commissions have oversight and a seat at the table in the strategic evaluation of the regional transmission system.

Q. PLEASE DESCRIBE THE PROCESS IN NORTH CAROLINA.

A. From the North Carolina Transmission Planning Collaborative website (http://nctpc.org/nctpc),

> *"The major electric load-serving entities (LSEs) of North Carolina, including Duke Energy Carolinas, Duke Energy Progress, ElectriCities of NC (municipals) and the North Carolina Electric Membership Corporation (cooperatives), have created the North Carolina Transmission Planning Collaborative (the "Process"). The Process was formed to enhance transmission planning by allowing all stakeholders to participate in shaping the future transmission network in the areas of North Carolina and South Carolina served by the LSEs. An administrator has been selected to facilitate the Process and to ensure that the interests of all stakeholders are fairly and meaningfully represented.*
>
> *Specifically, the Process is intended to create an integrated long-term transmission expansion plan that will result in a reliable (i.e., meets all applicable reliability criteria) and cost effective (i.e., lowest overall cost to consumers) transmission system. A Transmission Advisory Group ("TAG") will provide advice and recommendations to the LSEs for consideration for incorporation into the coordinated transmission expansion plan. The TAG membership is open to all parties interested in the development of the Process."*

Q. PLEASE DESCRIBE THE PROCESS IN ARIZONA.

A. Generally, the Arizona Corporation conducts a Biennial Transmission Assessment of the Ten-Year Plans for each utility in the state including hosting a series of public workshops to review the adequacy of the transmission system to serve load, to address reliability issues, assess the impact of changes from existing generation and integration of renewable resources.

Q. SHOULD THE COMMISSION CONSIDER ADOPTING SUCH A PROCESS TO AVOID SOME OF THE ISSUES THAT CONTINUE TO ARISE IN THE COMPANY'S TRANSMISSION PLANNING PROCESS?

A. Yes, this would be consistent with my previous recommendations to develop a statewide transmission planning collaborative approach which includes participation from Staff, consultants and all of the ITS Participants to develop a long-term strategic transmission plan as a stipulation of the approval of the Company's 2022 Integrated Resource Plan.

EVALUATION OF TEN-YEAR TRANSMISSION PLAN

Q. DID YOU PERFORM AN EVALUATION OF THE COMPANY'S TEN-YEAR TRANSMISSION PLAN AS PART OF YOUR REVIEW OF THIS FILING?

A. Yes, I reviewed the results of the Ten-Year Transmission Plan as filed in Technical Appendix Volume 3 Transmission Planning of the 2022 Integrated Resource Plan.

Q. WHAT WAS THE PURPOSE OF YOUR EVALUATION?

A. The purpose of the evaluation was to review and verify the results of the power flow analysis, including an investigation of the following questions:

(1) Would an independent verification of the power flow models provided by the Company identify the same system problems that the Company presented in Technical Appendix Volume 3 Transmission Planning?

(2) Would the solutions provided by the Company to alleviate the respective system problems?

Q. WHAT MODELS DOES THE COMPANY USE TO PERFORM THE ANALYSIS THAT SUPPORTS THE TEN-YEAR PLAN?

A. The Company has developed a set of base case power flow models that can be run on the Siemens PSS/E platform. The base cases test the performance of the transmission system under differing load levels, solar facility dispatch, hydroelectric facility dispatch and transfers between the MISO North and MISO South regions. The primary planning period is related to the summer season as this tends to be the time when the transmission system is the most stressed. The Company also develops base cases for other times of the year, but in all of the non-summer and non-off-peak cases, the MISO flow is consistently a 1,000 MW transfer from MISO North to MISO South. Also, solar generation is modeled off-line at the time of the winter peak, shoulder load level and during the spring minimum load level. The Company also has developed a series of Unit Off cases, where certain units are modeled as off-line under the different load levels for each base case. The list of Unit Off cases is not performed for each generator in the Company service territory. The Company also evaluates system performance under MaxGen cases, whereby generation in certain parts of the system are fully dispatched to assess the ability of the transmission system to move power from these areas to serve other parts of the system. The system performance is assessed under certain contingency conditions, which include NERC Transmission Planning (TPL-001-5) contingencies. Other Ten-Year Plan studies look at interface performance (NERC FAC-013-2), nuclear unit performance (NERC NUC-001) and system stability analyses.

Q. PLEASE DESCRIBE THE VERIFICATION PROCESS YOU CONDUCTED TO REVIEW THE COMPANY'S TEN-YEAR TRANSMISSION PLAN.

A. My team received a series of power flow models, associated input files and output reports from the Company as described in Technical Appendix Volume 3 of the Integrated Resource Plan filing. The first part of the verification process is a review of the power flow models to assess consistency in generation dispatch, load modeling, system topology, interchange between regions and application of any outages on transmission system elements. The second phase of the verification process involves running the power flow models to verify that the transmission system issues identified by the Company and the technical effectiveness of the solutions proposed by the Company are consistent with the results of the power flow analysis.

Q. DID THE COMPANY'S ANALYSIS EVALUATE WHETHER THE PROJECTS PROPOSED BY THE COMPANY WERE THE OPTIMAL SOLUTIONS WITH RESPECT TO COST?

A. No. The Company did not provide any analysis that indicated the projects were the optimal solutions with respect to cost. The power flow analysis only identifies possible solutions to meet various system conditions but does not evaluate the costs of those solutions.

Q. DID YOUR ANALYSIS EVALUATE WHETHER THE PROJECTS PROPOSED BY THE COMPANY WERE THE OPTIMAL SOLUTIONS WITH RESPECT TO COST?

A. No. We only verified that the proposed solutions addressed the identified need. No cost analysis was performed by the Company or by my team in an attempt to optimize the transmission system plan with respect to cost. The power flow analysis only identifies possible solutions to meet various system conditions, but does not evaluate the costs of those solutions.

Q. DOES THE ANALYSIS PERFORMED FOR THE TEN-YEAR PLAN APPEAR TO COMPLY WITH NERC TRANSMISSION PLANNING STANDARDS?

A. Without conducting a comprehensive review of all 12,000+ cases provided by Company, I agree that the types of cases that are developed and the contingency analysis that is performed is consistent with the NERC TPL standards.

Q. WHAT WERE THE RESULTS OF YOUR ANALYSIS OF THE INITIAL POWER FLOW CASES AND FILES PROVIDED BY THE COMPANY?

A. The summer peak power flow cases provided by the Company were reasonable with respect to load modeling and generation dispatch, except for Scherer Unit 3. As the Company noted,[1] the proposed Scherer Unit 3 retirement is not in the power flow cases used for Ten-Year Plan due to the case building finishing prior to the Company's decision to recommend retiring Scherer Unit 3. We did not note any issues with interchange, or transmission system topology. The Company has assumed that all facilities are in service for the Ten-Year Transmission Plan. This assumption is consistent with planning practices in other parts of the United States.

Q. WHAT WERE THE RESULTS OF THE SECOND PHASE OF THE VERIFICATION PROCESS?

[1] Hearing Transcript, volume 1, pp 258, ln 5-7

A. After verifying the consistency of the Company's summer peak power flow cases, we ran a sample of the 12,000+ power flow models. We ran the power flow models to verify the issues identified by the Company. Then we checked if the mitigation provided by the Company addressed the issue.

Q. WHAT WERE THE RESULTS OF YOUR ANALYSIS?

A. I found that the summer peak load flow cases were reasonable with respect to generation dispatch, load modeling, interchange and system topology. I was able to verify that the problems identified by the Company in Technical Appendix Volume 3 were consistent with the results of my analysis. I was also able to verify that the mitigation plans proposed by the Company successfully mitigated the identified problems.

Q. WHAT IS THE CONCLUSION OF YOUR ASSESSMENT OF THE COMPANY'S TEN-YEAR TRANSMISSION PLAN?

A. The Company has developed a Ten-Year Transmission Plan that appears to be reasonable with respect to the modeling, methodology and solutions that were generated.

EVALUATION OF THE COMPANY'S UNIT RETIREMENT STUDY

DECERTIFICATION OF PLANT BOULEVARD UNIT 1, PLANT WANSLEY UNITS 1-2 AND UNIT 5A, PLANT GASTON UNITS 1-4 AND UNIT A

Q. WHAT IS YOUR CONCLUSION REGARDING THE PROPOSED RETIREMENTS OF PLANT BOULEVARD UNIT 1, PLANT WANSLEY UNITS 1-2 AND 5A AND PLANT GASTON UNITS 1-4 AND UNIT A?

A. I do not disagree with the Company's plans to retire these assets from a transmission perspective.

DECERTIFICATION OF PLANT BOWEN UNITS 1-2

Q. WHAT IS THE PROPOSED PLAN FOR PLANT BOWEN UNITS 1 AND 2 IN THE 2022 IRP?

A. The Company anticipates retiring Plant Bowen Units 1 and 2 no later than December 31, 2027. The Company maintains that updated reliability assessments show that the earliest Plant Bowen Units 1 and 2 can be retired is in 2027, as this will provide the Company sufficient time to complete the necessary transmission system improvements to accommodate retirement of these units (Main Document at 11-74).

Q. HAS THE COMPANY PROVIDED A LIST OF TRANSMISSION FACILITIES THAT ARE REQUIRED TO BE CONSTRUCTED WERE THE COMPANY TO CHOOSE TO DECERTIFY PLANT BOWEN UNITS 1-2?

A. In the Unit Retirement Study, the Company provided a spreadsheet labeled "TS Asset Eval_URS_Steam_Units.xlsm" which contains the transmission projects assignable to decertification request. It appears that a series of power flow models were developed around a set of fleet scenarios that included combinations of retirement units. Fleet Scenario 0 includes avoided transmission facilities associated with Plant Wansley Units 1-2 and Plant Bowen Units 1-2.

Q. WHAT TRANSMISION FACILITIES ARE IN THAT TRANSMISSION EXPANSION LIST?

A. The following transmission projects are listed as being associated with the retirement of Plant Bowen Units 1-2:

- Blakely Primary – Webb (APC) 115 kV (2026 need date) – This project is not listed in Exhibit JWC-2 as being assignable to Plant Bowen Units 1-2 exclusively. It does appear to be assigned to Plant Wansley 1-2 in Exhibit JWC-2.
- Capitol Heights – Carter Hill Road – Fisk Road 115 kV (2026 need date) – This project only shows up in the aforementioned spreadsheet and is not included in Exhibit JWC-2
- Lagrange – North Opelika 230 kV new line (2027 need date) – This project is referenced in both the aforementioned spreadsheet and in Exhibit JWC-2. The need for this facility is tied to the combined retirement of Plant Wansley Units 1-2 and the retirement of Plant Bowen Units 1-2.
- Bonaire Primary – Echeconnee 115 kV (2030 need date) – This project is not listed in Exhibit JWC-2.

Q. PLEASE EXPLAIN HOW THE COMPANY DETERMINED THAT THESE FACILITIES WERE NEEDED IF PLANT BOWEN UNITS 1-2 WERE DECERTIFIED.

A. The retirement analysis for Plant Bowen Units 1-2 was performed in 2020, according to the company's response to STF-GDS-4-1 (TS). Subsequent studies have assumed additional retirements, such as the retirement of Plant Wansley Units 1-2 and Plant Gaston Units 1-4.

Q. WHAT IS YOUR RECOMMENDATION REAGRDING THE TRANSMISSION FACILITIES ASSOCIATED WITH THE RETIREMENT OF PLANT BOWEN UNITS 1-2?

A. I agree with the Company's assertion that Plant Bowen Units 1-2 can be retired by December 31, 2027 without any adverse impacts on the transmission system, assuming the timely completion of the transmission facilities listed above.

DISCUSSION OF PLANT SCHERER UNITS 1-2

Q. WHAT IS THE COMPANY'S PROPOSED PLAN FOR PLANT SCHERER UNITS 1-2?

A. At this time, the company has stated that the economics associated with Plant Scherer Units 1-2 are challenged (Main Document 11-75). In preparation for a potential retirement due to worsening economics, transmission system upgrades are being proposed which will permit the retirement of Plant Scherer Units 1-2 by December 31, 2028. This date is consistent with the fixed retirement date for Plant Scherer Unit 3.

Q. HAS THE COMPANY PROVIDED A LIST OF TRANSMISSION FACILITIES THAT ARE REQUIRED TO BE CONSTRUCTED WERE THE COMPANY TO CHOOSE TO DECETIFY PLANT SCHERER UNITS 1-2?

A. In the Unit Retirement Study, the Company provided a spreadsheet labeled "TS Asset Eval_URS_Steam_Units.xlsm" which contains the transmission projects assignable to decertification request. It appears that a series of power flow models were developed around a set of fleet scenarios that included combinations of retirement units. Fleet Scenario 0+Scherer 3 includes avoided transmission facilities associated with Plant

Wansley Units 1-2, Plant Bowen Units 1-2 and Plant Scherer Unit 3. Fleet Scenario 1 includes avoided transmission investment associated with Fleet Scenario 0 + Scherer 3 and Plant Scherer Units 1-2.

Q. WHAT TRANSMISION FACILITIES ARE IN THAT TRANSMISSION EXPANSION LIST?

A. The following transmission projects are listed as being associated with the retirement of Plant Scherer Units 1-2:

- Morrow – Yates Common 115 kV (2028 need date) – This project is listed in Exhibit JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units 1-2 and Plant Bowen Units 1-2.
- South Coweta Bank A (change need date from 2030 to 2028) – This project is listed in Exhibit JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units 1-2 and Plant Bowen Units 1-2.
- Bonaire Primary – Butler 230 kV (change need date to 2028 from 2030) – This project is listed in Exhibit JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units 1-2 and Plant Bowen Units 1-2.
- Hollingsworth Ferry – Yellow Dirt 230 kV (2028 need date) – This project is listed in Exhibit JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units 1-2 and Plant Bowen Units 1-2.

- Dresden – Hollingsworth Ferry 230 kV (2028 need date) – This project is listed in Exhibit JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units 1-2 and Plant Bowen Units 1-2.
- Gordon – Sandersville #1 115 kV (2028 need date) – This project is listed in Exhibit JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units 1-2 and Plant Bowen Units 1-2.
- Eufala – George Dam (COE) – Webb (APC) 15 kV (2030 need date) – This project is not listed in Exhibit JWC-2 but is included in TS Asset Eval URS Steam Units.xlsm, tab Transmission Calc, Row 52.
- Hammond – Weiss Dam (APC) 115 kV (2030 need date) – This project is listed in Exhibit JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units 1-2 and Plant Bowen Units 1-2.

Q. WHAT IS YOUR RECOMMENDATION REAGRDING THE TRANSMISSION FACILITIES ASSOCIATED WITH THE RETIREMENT OF PLANT SCHERER UNITS 1-2?

A. I agree with the Company's assertion that Plant Scherer Units 1-2 can be retired by December 31, 2028 without any adverse impacts on the transmission system, assuming the timely completion of the transmission facilities listed above.

DECERTIFICATION OF PLANT SCHERER 3

Q. WHAT IS THE PROPOSED PLAN FOR PLANT SCHERER UNIT 3 IN THE 2022 IRP?

A. The Company has assumed that Plant Scherer Unit 3 will be retired on December 31, 2028 (Main Document 11-75).

Q. HAS THE COMPANY PROVIDED A LIST OF TRANSMISSION FACILITIES THAT ARE REQUIRED TO BE CONSTRUCTED WERE THE COMPANY TO CHOOSE TO DECETIFY PLANT SCHERER UNIT 3?

A. The Company has stated that substantial transmission system upgrades will be required if Plant Scherer Units 1-3 are retired. The completion of the identified upgrades will be difficult to achieve prior to December 31, 2028 according to Company estimates. It does not appear that the Company has provided any facilities associated with just the retirement of Plant Scherer Unit 3.

Q. WHAT TRANSMISION FACILITIES ARE IN THAT TRANSMISSION EXPANSION LIST JUST FOR UNIT 3 ALONE?

A. In the Unit Retirement Study, the Company provided a spreadsheet labeled "TS Asset Eval_URS_Steam_Units.xlsm" which contains the transmission projects assignable to decertification request. It appears that a series of power flow models were developed around a set of fleet scenarios that included combinations of retirement units. Fleet Scenario 0+Scherer 3 includes avoided transmission facilities associated with Plant Wansley Units 1-2, Plant Bowen Units 1-2 and Plant Scherer Unit 3. The following transmission projects are listed in "TS Asset Eval_URS_Steam_Units.xlsm" as being associated with the retirement of Plant Scherer Unit 3:

- Bremen (GPCO) – Crooked Creek 115 kV (2028 need date)
- Bonaire Primary – Butler 230 kV (2030 need date)

- South Coweta Bank A (2030 need date)
- Dresden – Lagrange Primary 230 kV (2031 need date)

This list is not the same as what the Company provided in Exhibit JWC-2. The following list shows the facilities the Company has attributed to the combined retirement of Plant Wansley Units 1-2, Plant Bowen Units 1-2 and Plant Scherer Units 1-3.

Q. WHAT TRANSMISION FACILITIES ARE IN THE TRANSMISSION EXPANSION LIST FOR PLANT SCHERER UNITS 1-3 INSTEAD OF JUST UNIT 3 ALONE?

A. The following transmission projects are listed as being associated with the retirement of Plant Scherer Units 1-3, inclusive:

- Morrow – Yates Common 115 kV (2028 need date) – This project is listed in Exhibit JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units 1-2 and Plant Bowen Units 1-2.
- South Coweta Bank A (change need date from 2030 to 2028) – This project is listed in Exhibit JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units 1-2 and Plant Bowen Units 1-2.
- Bonaire Primary – Butler 230 kV (change need date to 2028 from 2030) – This project is listed in Exhibit JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units 1-2 and Plant Bowen Units 1-2.

- Hollingsworth Ferry – Yellow Dirt 230 kV (2028 need date) – This project is listed in Exhibit JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units 1-2 and Plant Bowen Units 1-2.
- Dresden – Hollingsworth Ferry 230 kV (2028 need date) – This project is listed in Exhibit JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units 1-2 and Plant Bowen Units 1-2.
- Gordon – Sandersville #1 115 kV (2028 need date) – This project is listed in Exhibit JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, Plant Wansley Units 1-2 and Plant Bowen Units 1-2.
- Eufala – George Dam (COE) – Webb (APC) 15 kV (2030 need date) – This project is not listed in Exhibit JWC-2 but is included in TS Asset Eval URS Steam Units.xlsm, tab Transmission Calc, Row 52.
- Hammond – Weiss Dam (APC) 115 kV (2030 need date) – This project is listed in Exhibit JWC-2 as being needed for the retirement of Plant Scherer Units 1-3, along with Plant Wansley Units 1-2 and Plant Bowen Units 1-2.

Q. WHAT IS YOUR RECOMMENDATION REAGRDING THE TRANSMISSION FACILITIES ASSOCIATED WITH THE RETIREMENT OF PLANT SCHERER UNIT 3?

A. I agree with the Company's assertion that Plant Scherer Unit 3 can be retired by December 31, 2028 without any adverse impacts on the transmission system, assuming the timely completion of the transmission facilities listed above.

DISCUSSION OF PLANT BOWEN UNITS 3-4

Q. WHAT IS THE COMPANY'S PROPOSED PLAN FOR PLANT BOWEN UNITS 3-4?

A. The current plan for Plant Bowen Units 3-4 assumes continued operation of the units with ELG controls until December 31, 2035 (Main Document 11-76). This is consistent with the modeling of Plant Bowen Units 3-4 in the power flow models for the Ten-Year Plan.

Q. HAS THE COMPANY PROVIDED A LIST OF TRANSMISSION FACILITIES THAT ARE REQUIRED TO BE CONSTRUCTED WERE THE COMPANY TO CHOOSE TO DECETIFY PLANT BOWEN UNITS 3-4?

A. The Company has not provided a list of transmission facilities that are required for the eventual retirement of Plant Bowen Units 3-4. The only references to transmission expansion related to this potential retirement is included as part of the North Georgia Reliability & Resilience Plan (Main Document 12-87 to 12-88) as well as the URS Steam Units workbook. There is a recognized need for additional transmission infrastructure in North Georgia due to the retirement of Plant Bowen Units 1-4, the need to deliver renewable resources from South and Central Georgia to the North Georgia load centers and to accommodate utility scale renewable procurements from North Georgia as part of the North Georgia Renewable RFP. However, no specific transmission plans have been developed by either the Company or the ITS Participants to address this identified need.

Q. WHAT IS THE PATH THE COMPANY IS USING TO DEVELOP THIS PLAN?

A. The Company is currently working with the ITS Participants to develop the North Georgia Reliability & Resilience Action Plan, which will hopefully consider transmission solutions, as well as other alternatives. Given the complexity of this problem, I would encourage the Company to consider a more collaborative approach with Staff and the Commission in the study process.

Q. WHAT TRANSMISION FACILITIES ARE IDENTIFIED IN THE UNIT RETIREMENT STUDY?

A. In the Unit Retirement Study, the Company provided a spreadsheet labeled "TS Asset Eval_URS_Steam_Units.xlsm" which contains the transmission projects assignable to decertification request. It appears that a series of power flow models were developed around a set of fleet scenarios that included combinations of retirement units. By comparing the facilities from Fleet Scenario 2 to Fleet Scenario 1 a residual list of projects can be inferred. This residual list of transmission projects associated with the retirement of Plant Bowen Units 3-4 is:

- Arlington Primary – Greenhouse Road 115 kV (2028 need date)
- Corn Crib – Lagrange 115 kV (2028 need date) – This project is included in the Company's One-Year Plan.
- East Dalton – Oostanaula 115 kV (2028 need date) – This project is included in the Company's One-Year Plan.
- Dalton – Loopers Farm 230 kV interface (2028 need date)
- Dyer Road – South Coweta 115 kV (2030 need date)
- Hickory Level – Villa Rica Primary 230 kV (2030 need date)
- Union City – Yates (Black) 230 kV (2030 need date)

- Union City – Yates (White) 230 kV (2030 need date)
- Eufala – George Dam (COE) – Webb (APC) 115 kV (2030 need date)
- Barnesville Primary – South Griffin 115 kV (2030 need date)

Q. PLEASE EXPLAIN HOW THE COMPANY DETERMINED THAT THESE FACILITIES WERE NEEDED IF PLANT BOWEN UNITS 3-4 WERE DECERTIFIED.

A. It does not appear that the Company performed any power flow analyses of just the retirement of Plant Bowen Units 3-4. All studies that evaluated the retirement of Plant Bowen Units 3-4 also assume the retirements of Plant Wansley Units 1-2 and Unit 5A, Plant Gaston Units 1-4 and Unit A, Plant Bowen Units 1-2 and Plant Scherer Units 1-3. The following is a copy of the transcript from the April 4 Hearing (Page 258, Lines 12-18):

> Q. Are there reasons related to transmission projects that the company's position is that Bowen 3 and4 cannot be retired before 2035?
> A. (Witness Robinson) Yes. So when we looked at the retirement of Bowen 3 and 4 on top of the other units, in the rank order that we used to study those, we saw significant transmission that needed to be completed.

Q. DID THE COMPANY PERFORM ANY SENSITIVITY ANALYSES REGARDING THE NEED FOR TRANSMISSION FACILITIES ASSOCIATED WITH THE POTENTIAL DECERTIFICATION OF PLANT BOWEN UNITS 3-4?

A. The Company evaluated multiple scenarios related to the retirement of Bowen Units 3-4. Most of the scenarios evaluated local maximum generation output cases and several generator off cases. These cases reflected various redispatch patterns and different locations for proxy generation.

Q. WHAT WERE THE RESULTS OF THAT SENSITIVITY ANALYSIS?

A. The results of the sensitivity analysis revealed that the need for transmission was highly dependent on the location of proxy generation and existing unit dispatch. This volatility in the results showed that the feasibility of retiring the units earlier may have been technically possible in some cases, but that the timing requirements surrounding construction of the necessary upgrades may not be practical with respect to facility construction.

Q. HAS THE COMPANY PROVIDED ANY DETAILS REGARDING THE TIMING REQUIREMENTS ASSOCIATED WITH THE CONSTRUCTION OF FACILITIES THAT ARE REQUIRED BY 2028?

A. The Company did not provide any analysis to support the timing issue, but only generally addressed the construction and outage schedules associated with transmission expansion.

Q. DO YOU AGREE WITH THE COMPANY'S FILING THAT THE IDENTIFIED FACILITIES ARE NECESSARY TO MAINTAIN SYSTEM RELIABILITY WITH PLANT BOWEN UNITS 3-4 RETIRED?

A. I generally agree with the assertion that Plant Bowen Units 3-4 will require some level of transmission construction in order to be retired, however, I would support additional analysis of the facilities required due to a lack of alternatives being included in this IRP. The level of reliability is speculative depending on generation dispatch levels and the location of proxy generation included in the cases in future years.

Q. WHAT IS YOUR RECOMMENDATION REAGRDING THE TRANSMISSION FACILITIES ASSOCIATED WITH THE RETIREMENT OF PLANT BOWEN 3-4?

A. Although it is reasonable to consider retirement of Plant Bowen Units 3-4 by 2029 due to the technical feasibility of implementing transmission solutions prior to 2028, it's not clear the Company has sufficiently investigated transmission alternatives that would allow it to avoid the required ELG compliance plan for Units 3-4. With ELG investments, the timing of the retirement for Bowen 3-4 should be considered in the 2025 IRP or as part of an integrated analysis to address the North Georgia reliability and resilience issues, including results from the Renewable RFP. The Company's power flow analysis demonstrates that the location and volumes of replacement capacity is a significant driver of the required transmission system upgrades. Having better clarity from the Renewable RFP will result in a transmission solution that is right-sized for North Georgia.

BATTERY ENERGY STORAGE SYSTEM (BESS)

Q. PLEASE DESCRIBE THE COMPANY'S PLANS IN THE 2022 IRP RELATED TO BATTERY STORAGE.

A. The Company has proposed the addition of the McGrau Ford Battery Facility, which is a 265-MW, 2-hour lithium-ion facility. This facility is planned to be in service by 2026. This project is in addition to two projects the Company is developing in response to the approvals given in the 2019 IRP.

Q. WHAT DID THE COMPANY PROPOSE REGARDING BATTERY STORAGE IN THE 2019 IRP?

A. The Company proposed the development of 80 MW of Company-owned and operated Battery Energy Storage Systems (BESS) in the 2019 IRP. There are two demonstration projects that make up this total. The first is the 65 MW, 4-hour lithium-ion project at the Mossy Branch Battery Facility, which was approved by the Commission in an Order dated October 12, 2021. This project is expected to go inter service in 2023. The remainder of the 2019 BESS volume is the Fort Stewart BESS operating in conjunction with an existing solar facility at that location. The in-service date for this facility is the second half of 2024.

Q. HOW DID THE COMPANY SELECT THE MCGRAU FORD SITE AS THE OPTIMAL LOCATION FOR A BATTERY STORAGE SYTSEM?

A. The Company made their decision based on ease of interconnection, low interconnection costs and other economic factors. The impact on local reliability does not appear to be one of the factors the Company considered.

Q. ARE THERE ANY OTHER PROJECTS PLANNED FOR THE MCGRAU SITE THAT COULD IMPACT THE EVALUATION OF THE PROPOSED ENERGY STORAGE PROJECT?

A. Yes. In the Ten-Year Plan, the ITS has proposed the addition of a +/- 150 MVAR STATCOM at the McGrau Ford 230 kV bus by December 1, 2023. This is a new project and is the result of the Company's stability analysis. The addition of a STATCOM in addition to an Energy Storage System may make it difficult to isolate the benefits of the Energy Storage System, particularly with respect to the Ancillary Services benefits an ESS can provide.

Q. THE COMPANY HAS STATED THAT THE STATIC VAR COMPENSATOR (STATCOM) IS NEEDED TO ADDRESS FIDVR IN NORTH GEORGIA. WHAT

IS IT ABOUT THE NORTH GEORGIA PORTION OF THE COMPANY'S TRANSMISSION SYSTEM THAT MAKES IT SUSEPTICAL TO FIDVR?

A. The addition of high levels of Distributed Energy Resources, particularly those that have limited reactive support, can exacerbate the effects of FIDVR.

Q. WHAT IS FIDVR?

A. FIDVR or Fault-Induced Delayed Voltage Recovery refers to the unexpected delay in the recovery of voltage to its nominal value following the normal clearing of a fault.

Q. WHAT IMPACT DOES A HIGH PENETRATION OF SOLAR PV GENERATION HAVE ON THE EFFECTS OF FIDVR?

A. The addition of high levels of Distributed Energy Resources, particularly those that have limited reactive support, can exacerbate the effects of FIDVR.

Q. HAS THE COMPANY PROVIDED ANY INFORMATION ON HOW THEY PLAN TO OPERATE THE PROPOSED STORAGE FACILITIES?

A. The Company has not stated that the ESS facilities will be operated in a manner other than to provide transmission system support, particularly when paired with solar facilities at the same location.

Q. SHOULD THE OPERATION OF THE PROPOSED FACILITIES HAVE A POSITIVE IMPACT ON THE RELIABILITY OF THE COMPANY'S TRANSMISSION SYSTEM?

A. Yes.

Q. DOES THE COMPANY PLAN TO OPERATE THESE FACILITIES TO PROVIDE ADDITIONAL SUPPORT TO THE COMPANY'S TRANSMISSION SYSTEM, SUCH AS ANCILLARY SERVICES?

A. That is still to be determined.

RECOMMENDATIONS AND STIPULATIONS

Q. WHAT RECOMMENDATIONS DO YOU HAVE REGARDING THE REVIEW OF THE TEN-YEAR TRANSMISSION PLAN?

A. I recommend that Commission approve the results of the Ten-Year Transmission Plan as being acceptable for meeting Company and NERC reliability standards.

Q. WHAT CONCLUSIONS HAVE YOU REACHED REGARDING THE AVAILABILITY OF REQUIRED TRANSMISSOIN RESULTING FROM THE DECERTIFICATION OF CERTAIN GENERATION FACILITIES REQUESTED BY THE COMPANY?

A. Consistent with the Company's request, I conclude that there are no transmission-related impediments to the retirement of Plant Wansley and Plant Boulevard retirements as planned on August 31, 2022. Similarly, there are no transmission-related impediments to the retirement of Plant Bowen Units 1-2 as planned on December 31, 2027, Plant Gaston or Plant Scherer Units 1-3 as planned on December 31, 2028.

With respect to the retirement of Plant Bowen Units 3-4 I conclude that alternative traditional transmission solutions were not fully explored by the Company. It's not clear that the solutions proposed by the Company are the only solutions, and the Company did not provide an analysis of whether these were optimal with respect to cost. It is not known, and the Company did not investigate, whether transmission alternatives exit that would allow the Company to retire Bowen 3-4 by December 2028 and avoid the required ELG compliance plan. With ELG investments, the timing of the retirement for Bowen 3-4 should be considered in the 2025 IRP or as part of an integrated analysis to address the North Georgia reliability and resilience issues, including results from the Renewable RFP. I am recommending the Company complete the assessment of transmission facilities associated with this retirement, and the additions from the Renewable RFP by September 1, 2023, so the Commission has time to properly evaluate the transmission solution prior to the 2025 Integrated Resource Plan.

Q. WHAT RECOMMENDATIONS DO YOU HAVE REGARDING THE APPROVAL OF THE BATTERY STORAGE FACILITIES REQUESTED BY THE COMPANY?

A. If the ESS facilities are approved by the Commission, the Company should be required to provide annual feedback to the Commission regarding performance of the ESS facilities, including performance during outages and use of the facilities to provide ancillary services.

Q. WHAT RECOMMENDATIONS DO YOU HAVE REGARDING THE NORTH GEORGIA RELIABILITY AND RESILIENCE ACTION PLAN?

A. Given that the Company has not proposed any projects related to the Action Plan, I recommend that the Commission establish a collaborative transmission planning process which includes Staff and consultants and all ITS Participants to meet on a quarterly basis to follow the activities of the Georgia ITS as problems are identified and solutions are developed to address the deliverability issues in North Georgia including the development of the long-term North Georgia Reliability and Resilience Action Plan. I also recommend that the Company be required to provide quarterly updates to the Commission on the progress of the North Georgia Reliability and Resilience Action Plan and that the Commission open a public proceeding to discuss the Company's plan prior to the 2025 Integrated Resource Plan Submittal.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.