BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:	**)**	
Georgia Power Company's	**)**	**Docket No. 55378**
2023 Integrated Resource Plan Update	**)**	

REDACTED – PUBLIC VERSION

Testimony & Exhibits

of

Jeffry Pollock

On Behalf of

Georgia Association of Manufacturers

February 15, 2024

J. POLLOCK
INCORPORATED

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LIST OF EXHIBITS

Exhibit	Description
JP-1	S&P Capital IQ PRO, *Duke Looks to Add More Gas, Offshore Wind to Meet Demand Boom in NC, SC*, Feb. 5, 2024
JP-2	Amended and Restated Southern Company System Intercompany Interchange Contract
JP-3	Southern Company Services, Inc. 2024 Informational Filing – IIC – Docket No. ER10-171-000, Schedule 3.

GLOSSARY OF ACRONYMS

Term	Definition
APC	Alabama Power Company
BESS	Battery Energy Storage System
DER	Distributed Energy Resource
DPEC	Demand Plus Energy Curtailment
DR	Demand Response
GAM	Georgia Association of Manufacturers
GPC	Georgia Power Company
IIC	Southern Company Intercompany Interchange Contract
IRP	Integrated Resource Plan
kW	Kilowatt
MPC	Mississippi Power Company
MW	Megawatt(s)
MWh	Megawatt-Hour
PPA	Power Purchase Agreement
RFP	Request for Proposals
ROE	Return on Equity
Santa Rosa	Santa Rosa Energy Center, LLC

TESTIMONY OF JEFFRY POLLOCK

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock; 14323 South Outer 40 Rd., Suite 206N, St. Louis, MO 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from Washington University in St. Louis, Missouri. Since graduation in 1975, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in both the United States and several Canadian provinces. My qualifications are documented in **Appendix A.** A list of my appearances is provided in **Appendix B** to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Georgia Association of Manufacturers (GAM). The members of GAM are customers of Georgia Power Company (GPC). They consume large quantities of electricity, primarily for manufacturing under a variety of rate schedules.

Q DID YOU ALSO SPONSOR TESTIMONY ON BEHALF OF GAM IN GPC'S 2022 INTEGRATED RESOURCE PLAN (IRP) FILING?

A Yes.

Q WHAT ISSUES ARE YOU ADDRESSING IN THIS IRP UPDATE?

A First, I discuss the extraordinary circumstances leading to GPC updating its 2022 approved IRP. Second, I shall discuss each of the following issues:

- Deferred accounting;
- Additional sum;
- Specific capacity additions; and
- Proposed Distributed Energy Resource (DER) and Demand Response (DR) tariffs.

Q DOES THE FACT THAT YOU ARE NOT ADDRESSING ALL ISSUES IN THIS PROCEEDING CONSTITUTE AN ENDORSEMENT OF GPC'S POSITIONS ON THE ISSUES?

A No. The fact that I am not addressing every issue should not be interpreted as an endorsement of GPC's proposals in this proceeding.

Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR DIRECT TESTIMONY?

A Yes. I am sponsoring **Exhibits JP-1**, **JP-2**, and **JP-3**.

Summary

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A Given the extraordinary circumstances surrounding the IRP update, specifically, the dramatic increase in load growth prompting GPC to accelerate future capacity additions, the Commission should be highly skeptical of GPC's proposals on deferred accounting and an additional sum. My findings and recommendations are as follows:

Deferred Accounting

- Deferred accounting is an extraordinary regulatory practice. It should only be used when it is necessary either to prevent material harm to the utility's financial integrity, thereby placing its credit rating in jeopardy, or to provide more stable rates, thereby averting rate shock for the benefit of the utility's customers.
- GPC has failed to demonstrate the need for deferred accounting in this proceeding. The net deferred capacity costs that GPC will incur under the power purchase agreements (PPAs) with Mississippi Power Company (MPC) and Santa Rosa Energy Center, LLC (Santa Rosa) are only a fraction of the incremental non-fuel revenues that GPC will recover because of accelerated load growth in 2024 and 2025, even prior to remarketing additional capacity.
- GPC has already remarketed 500 megawatts (MW) of capacity from the MPC PPA and is currently negotiating to remarket the remaining MPC capacity, as well as capacity under the Santa Rosa PPA. To the extent this additional capacity is remarketed, GPC will receive ample revenues to offset the capacity payments.
- Under the rates approved in the 2022 rate case, GPC has more than ample earnings headroom to absorb the PPA capacity costs and still earn well within the authorized return on equity (ROE) band. Further, GPC has consistently earned well above the authorized mid-point ROE and, in seven of the past eleven years, its earned ROE exceeded the top end of the authorized range.
- The Commission should reject GPC's deferred accounting proposals.

Additional Sum

- GPC is proposing a $3 per kilowatt (kW) year for each year of the five-year terms of the MPC and Santa Rosa PPAs. If approved, GPC would receive $2.79 million per year (nearly $14 million over the five-year terms), and these payments would flow immediately to GPC's earnings.
- Unlike the six PPAs approved in the 2022 IRP that were competitively procured, GPC had few good options to increase capacity to meet dramatic and unexpected load growth.
- Because of the dramatic increase in load growth, GPC does not need an incentive to procure capacity. Further, the capacity price under the MPC PPA is higher than the capacity equalization rate prescribed under the Southern Company Intercompany Interchange Contract (IIC). Accordingly, there are no shared savings. Coupled with changed circumstances, specifically the greater risks to retail customers from accelerated load growth, and the absence of any lost revenues, the MPC and Santa Rosa PPAs do not meet the criteria for an additional sum.

- The Commission should reject GPC's proposed additional sum on the MPC and Santa Rosa PPAs.

Specific Capacity Additions

- The purchase of capacity from a GPC affiliate, MPC, is occurring through a separate PPA, rather than through the longstanding IIC.
- The IIC provides a contractual basis for the continued operation of the electric facilities of the Southern Operating Companies as a fully integrated power pool. In addition to joint resource planning, dispatch, and sharing of opportunity sales/purchases, the IIC provides a mechanism for sharing temporary capacity surpluses and deficits between and among each Operating Company. The "reserve sharing" payment is based on the installed cost of a dispatchable peaking resource.
- The IIC is premised on each Operating Company having sufficient resources to meet its own needs in the long-term. However, there is no prohibition or restriction on the duration of reserve sharing transactions.
- GPC's assertion that MPC would have retired the capacity in the absence of the PPA is contrary to the IIC and prudent resource planning. MPC would not have implemented its proposed retirement plan if the (to be retired) capacity was needed by the Operating Companies to maintain reliability, and MPC was compensated for the costs of these resources.
- GPC will incur higher purchased capacity costs under the MPC PPA than under the IIC. This is yet another reason for rejecting an additional sum on the MPC PPA.
- The pairing of a battery energy storage system (BESS) and solar arrays at the [redacted] site are, by far, the most expensive of the proposed capacity additions in this IRP update. The excessive cost is not due to the BESS, which is not significantly different than the costs of the proposed BESSs at the Robins and Moody military bases — rather, it is due to the solar arrays that would be used solely to charge the BESS.
- The cost of using solar arrays to charge the BESS at [redacted] is projected to be significantly higher than GPC's projected avoided energy cost under all planning scenarios, except for the High Gas $20/ton carbon cost (HG20). In other words, absent high gas prices and a $20 carbon adder, it would be more cost-effective to use the grid to charge the BESS.
- Accordingly, if the Commission approves the [redacted] project, it should only do so for the individual BESS component.

Proposed DER and DR Tariffs

- GPC is proposing two new rate schedules (DCL-1 and DCO-1) to expand the installation of DERs and a new DR rate schedule, CL-1.
- While expanding DERs and DR can encourage action by customers to help alleviate projected capacity shortages, while also increasing resiliency, customers would have to be able to properly assess the risks and benefits before giving serious consideration to these alternatives. In this respect, GPC's proposals would have undue discretion in determining the amount of the credits/payments, renewal terms, penalties and other significant terms and conditions. Accordingly, the Commission should not approve the proposed DER/DR rate schedules as filed.
- Specific improvements should include:
  - Providing a specific definition of "system value" and requiring GPC to seek Commission review and approval of the methodology and assumptions (by describing the methodology and providing a specific quantification) used to determine system value prior to approving the new rate schedules, both initially and in each subsequent year.
  - Requiring GPC to provide at least six months advance notice before any DER/DR rate schedule is discontinued and obligating GPC to compensate customers for any investments that may become stranded as a result of program termination.
- Additional changes should include:
  - Schedule DCL-1 should be revised to allow the customer to be directly involved in competitively procuring the DER and related equipment.
  - Schedule DCO-1 should not limit the size of a customer-owned DER to 10 MW. Also, it should be clear that the customer can outsource the installation, including any fuel supply, and to ensure that the customer can continue to use any thermal energy produced by the DER facility, even when it is being dispatched by GPC to meet system needs.
  - Schedule CL-1 should be revised: (1) to include a more specific definition of the circumstances that constitute a Demand Response Event; (2) to set the credits to reflect the full (not discounted) avoided cost of capacity (including transmission if curtailments can occur due to shortages or congestion with the transmission system); (3) the compliance incentive should not exceed the value of the credit; and (4) customers should have the option to choose from among a menu of options including contract duration and curtailment hours and receive credits that reflect the value of the selected option.

2. OVERVIEW

Q WHAT CIRCUMSTANCES ARE DRIVING GPC TO UPDATE THE IRP THAT WAS JUST APPROVED IN 2022?

A The IRP update is precipitated by much higher load growth than was projected in the 2022 IRP. GPC is now projecting winter peak demand growing at a compound annual rate of 4% for the period 2023 through 2033. This is in stark contrast to the 0.4% per year growth rate projected by GPC in its 2022 IRP. The accelerated growth would translate into a 7,600 MW increase in peak demand by the year 2033. As a consequence of the higher-than-projected load growth, GPC's winter reserve margins are projected to fall below the target reserve margin by the winter of 2026-27, thereby triggering a capacity need. Previously, GPC did not project a capacity need until the winter of 2028-29.

Accelerating load growth and capacity needs are, indeed, extraordinary circumstances. Meeting the challenges created by these extraordinary circumstances will require creative, rather than business-as-usual, solutions.

Q HAS GAM OPINED ON THE REASONABLENESS OF GPC'S UPDATED LOAD FORECAST?

A No. GAM shares and understands the concerns about both the sudden change and the unprecedented amount of load growth that GPC is now projecting. However, GPC is not alone in experiencing accelerated load growth.

Due to the influx of data centers, battery and electric vehicle manufacturing, and related industries, the Southeast is experiencing rapid load growth, thereby necessitating a more rapid increase in capacity resources. For example, GPC affiliate

Alabama Power Company (APC) has issued a Request for Proposals (RFP) for new capacity resources available to commence service by December 1, 2028.[1] Further, Duke Energy Carolinas and Duke Energy Progress recently filed updated IRPs citing "unprecedented economic development growth through 2023 that is well beyond the Companies' historical experience, resulting in substantial, material changes in the Companies' load forecast since the Companies prepared their initial Plan."[2] These updated IRPs project "eight times the peak load growth" anticipated just less than two years ago, increasing 2030 peak demand by about 2,100 MW.[3] The higher load growth is projected to trigger additional needed capacity. A recent S&P Capital IQ PRO article discussing the updated IRPs is provided in **Exhibit JP-1.**

Q ARE THERE BOTH BENEFITS AND RISKS ASSOCIATED WITH LOAD GROWTH?

A Yes. If the projected load growth does not materialize, GPC would incur additional costs that would either have to be recovered in rates or through sales of surplus capacity to other utilities that have a capacity need. On the other hand, what load growth does materialize will produce additional revenues that reflect GPC's current system costs, including the recently completed Vogtle Unit No. 3 and soon to be commissioned Unit No. 4. Load growth means that GPC will be selling more electricity to customers. This, in turn, will create additional sales and revenues over which GPC's

[1] https://www.alabamapower.com/content/dam/alabama-power/pdfs-docs/company/rfp/apc-2023-capacity-rfp.pdf

[2] *In the Matter of Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-110.9 and § 62-110.1(c)*, Docket No. E-100, Sub 190, Verified Amended Petition for Approval of 2023-2024 Carbon Plan and Integrated Resource Plans for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC at 11 (Jan. 31, 2024).

[3] *Id.* at 11-12.

system costs, including the substantial additional costs associated with Vogtle Unit Nos. 3 and 4, can be spread over more billing units, thereby placing downward pressure on rates.

For example, under its P50 projected load growth for 2024 and 2025, I estimate that GPC will recover $[redacted] of additional non-fuel revenues, without incurring any incremental production capacity costs.[4] These additional revenues would be even higher based on the P95 forecast used by GPC in its revised load forecast.

Further, the projected capacity additions, including the six PPAs approved in the 2022 IRP and the two additional PPAs proposed in this IRP update, are expected to have lower incremental fixed costs than GPC's existing capacity resources. Thus, these capacity additions will also place downward pressure on rates.

Q GIVEN THE EXTRAORDINARY CIRCUMSTANCES SURROUNDING THE IRP UPDATE, SHOULD THE COMMISSION TAKE A "BUSINESS-AS-USUAL" APPROACH TO ADDRESSING THE ISSUES RAISED IN THIS PROCEEDING?

A No. In particular, the Commission should be highly skeptical of GPC's proposals to defer expenses and earn additional sums for the reasons discussed in the following sections.

[4] A P50 projection means that there is an equal likelihood that load growth could be higher or lower than the projected load.

3. DEFERRED ACCOUNTING

Q WHAT IS DEFERRED ACCOUNTING?

A Deferred accounting is a process whereby a utility is authorized by the Commission to defer, rather than immediately expense, a specific cost for recovery in a future period. If a cost is immediately expensed, it could have an immediate (and potentially material) impact on a utility's earnings; whereas, deferring the expense would match the expense with future revenues while spreading the burden of that cost into the future.

Q IS DEFERRED ACCOUNTING A NORMAL REGULATORY PRACTICE?

A No. Deferred accounting is an extraordinary regulatory practice. It is only used when it is necessary either to prevent material harm to the utility's financial integrity, thereby placing its credit rating in jeopardy, or to provide more stable rates, thereby averting rate shock for the benefit of the utility's customers.

Q IS DEFERRED ACCOUNTING ALWAYS APPROPRIATE?

A No. Deferred accounting shifts regulatory risk from a utility's shareholders onto customers. Thus, it is contrary to the regulatory compact in which a utility should have an *opportunity* — not a *guarantee* — to earn a reasonable return on its investment in the facilities used in providing electricity to its captive customers. Therefore, deferred accounting should be used sparingly, such as when a utility incurs an extraordinary cost, such as storm damage, or it becomes necessary to spread recovery of that cost over a reasonable period to prevent harm to a utility's financial integrity or avoid rate shock for customers.

Q IS DEFERRED ACCOUNTING AN ACCEPTED PRACTICE IN GEORGIA?

A Yes.

Q WHAT COST IS GPC ASKING THE COMMISSION TO DEFER FOR FUTURE RECOVERY?

A GPC is asking the Commission to defer recovery of the capacity payments under both the MPC and Santa Rosa PPAs and certain development costs.[5] The proposed PPA capacity deferrals are summarized in Table 1.

Table 1
Estimated Incremental Revenue Requirements for Net Deferred Costs of PPAs
(Millions)

Description	2024	2025	2026	2027	2028
Mississippi Power PPA	[redacted]				
Regional Sale PPA					
Santa Rosa PPA					
Total Amount Deferred					
Reg Asset Beginning Balance	[redacted]				
Amortization					
Reg Asset Ending Balance					
Deferred Tax Liability					
Average					
Pre-Tax WACC					
Financing Cost on Reg Asset					

Source: GPC Trade Secret Response to STF-DEA-3-6, Supplemental Attachment A.

[5] Georgia Power Company, 2023 Integrated Resource Plan Update, Main Document at 4.

As can be seen, GPC projects that the impact of the two PPAs would increase net operating expenses by $[redacted] and $[redacted] in 2024 and 2025, respectively. This projection assumes, however, that only 500 MW of the MPC PPA capacity is remarketed. GPC is actively marketing the remaining 250 MW of the MPC PPA capacity, as well as capacity from Santa Rosa.[6] If these efforts are successful it will further minimize the impact of the new PPAs on future earnings.

Q HOW WOULD THE DEFERRED CAPACITY PAYMENTS BE RECOVERED?

A Under GPC's proposal, the $[redacted] of accumulated deferred capacity payments would be recovered over three years, beginning in 2026. The recovery of the deferred capacity payments would coincide with the incurrence of ongoing capacity payments under both the MPC and Santa Rosa PPAs.

Q IS GPC'S ACCOUNTING PROPOSAL NECESSARY TO AVERT EITHER DETERIORATING FINANCIAL INTEGRITY OR TO STABILIZE ITS EARNINGS AND REVENUES?

A No. First, even if GPC is not successful in marketing more than the 500 MW that is already under contract, the resulting deferrals in 2024 and 2025 are immaterial and would have little impact on GPC's authorized ROE. If, on the other hand, GPC's efforts to remarket additional capacity from the two PPAs are successful, there will be little or no impact.

Second, as previously explained, GPC will collect an additional $[redacted] of non-fuel revenues due to projected load growth in 2024 and 2025 that would more than offset the deferred expenses.

[6] GPC Response to STF-JKA-4-19.

Third, GPC has had no difficulty earning its authorized 10.5% ROE. In seven of the past eleven years, GPC's earned ROE has exceeded 12%. Most recently, the Commission determined that GPC had earned a 13.69% ROE, and, as a consequence, GPC incurred $293 million of excess revenues.[7] The revenue spread between a 10.5% and 11.9% ROE would exceed $275 million per year,[8] which is more than [redacted] times the annual capacity expense under the MPC and Santa Rosa PPAs. Thus, GPC has more than ample "headroom" to expense, rather than defer, the MPC and Santa Rosa PPA capacity costs and not sustain any material harm in its financial integrity or credit rating.

Finally, the Company's proposal would effectively allow a double-return on the deferred costs. This is because GPC is proposing to add carrying charges on the amortized balance of the deferrals, while also recovering an additional sum.

Q WHAT DO YOU RECOMMEND?

A The Commission should reject GPC's deferred accounting proposal. Given the extraordinary circumstances of this IRP update, deferred accounting should only be used if the expense in question would have a material adverse impact on the utility or it would destabilize rates. GPC already has more than ample earnings to absorb the expense without causing any material adverse impact on earnings, and if its efforts to sell the remaining capacity are successful, there will be no impact.

[7] *In Re: Georgia Power Company's 2019 Rate Case*, Docket No. 42516, Order on Georgia Power Company's 2022 Annual Surveillance Report at 1 (Jul. 31, 2023).

[8] The difference in the pre-tax rate of return between an 11.9% and a 10.5% ROE is approximately 1%. GPC's projected 2024-2025 rate base averages $27.7 billion. Thus, 1% of $27.7 billion is $277 million.

4. ADDITIONAL SUM

Q IS GPC PROPOSING TO RECOVER AN ADDITIONAL SUM ON THE MPC AND SANTA ROSA PPAS?

A Yes. GPC is proposing to recover $3 per kW-year for each year of the five-year terms of the two PPAs. This includes the years 2024 and 2025 during which GPC concedes it does not need the capacity from the PPAs. If approved, GPC would receive $2.79 million per year, and these payments would flow immediately to GPC's earnings. Over the five-year terms, GPC would receive nearly $14 million of additional earnings.

Q WHY IS GPC REQUESTING AN ADDITIONAL SUM ON THE TWO NEW PPAS?

A GPC states that its request is consistent with the additional sum approved on the six capacity PPAs in the 2022 IRP.[9]

Q IS CONSISTENCY A NECESSARY AND SUFFICIENT REASON TO GRANT AN ADDITIONAL SUM ON THE MPC AND SANTA ROSA PPAS?

A No. As previously discussed, the extraordinary circumstances surrounding this IRP update proceeding clearly warrant a significant policy change.

For example, the two PPAs are among the very few good options available to obtain the capacity GPC needs on a short-term basis to maintain reliability for all retail customers — existing and new. Further, accelerated load growth could limit the Company's ability to competitively procure capacity additions. Neither the MPC nor the Santa Rosa PPAs were procured competitively. This is clearly a changed circumstance, unlike the six capacity PPAs approved in the 2022 IRP that were procured through a competitive process. Further, as discussed later, the PPA with

[9] Direct Testimony of Jeffrey R. Grubb, Franscisco Valle, Lee Evans and Michael A. Bush at 33-34.

affiliate MPC could have been procured through an existing mechanism at a lower cost. Finally, retail customers are clearly at risk if GPC's load projections are, in retrospect, inaccurate.

Q WHAT ARE THE REQUIREMENTS FOR AWARDING AN ADDITIONAL SUM?

A The requirements are stated in the Commission Rules:

> The certified or actual cost, whichever is less, of purchase of any certificated long-term power purchase shall be recovered in rates by the utility along with the additional sum as determined by the Commission ***to encourage such purchases. The Commission shall consider lost revenues, if any, changed risks, and an equitable sharing of benefits between the utility and its retail customers***…[10] (emphasis added)

Q DID THE MPC AND SANTA ROSA PPAS MEET THESE REQUIREMENTS?

A No. First, as previously stated, given the limited options available, there is no need to provide GPC an incentive to procure the least costly capacity — neither time nor options permit a choice for which they could be encouraged. Second, because the PPAs were not competitively procured, there are no benefits to be shared with retail customers vis-à-vis a self-build resource or other capacity alternatives. In fact, as discussed later, the MPC PPA will be more expensive than if this capacity had been procured through the IIC. Third, retail customers are clearly at greater risk due to the potential impact on system reliability due to accelerated load growth – a circumstance that has clearly changed since the 2022 IRP.

Q WHAT DO YOU RECOMMEND?

A The Commission should reject the proposed additional sum on the MPC and Santa Rosa PPAs.

[10] Ga Comp. R. & Regs. 515-3-4-.11 (Cost Recovery and Financial Incentives); *See also*, O.C.G.A. § 46-3A-8.

5. SPECIFIC CAPACITY ADDITIONS

Q WHAT CAPACITY ADDITIONS ARE YOU ADDRESSING?

A I shall discuss the MPC PPA and the [redacted] BESS/Solar Project.

MPC PPA

Q YOU PREVIOUSLY STATED THAT GPC COULD HAVE PROCURED CAPACITY FROM MPC THROUGH THE IIC. WHAT IS THE IIC?

A The IIC is a FERC-approved tariff by and between APC, GPC, MPC and Southern Power Company (collectively, the "Operating Companies") which operate as an integrated electric utility system and Southern Company Services, Inc. A copy of the currently effective IIC is provided in **Exhibit JP-2**.

Q WHAT IS THE PURPOSE OF THE IIC?

A The IIC provides a contractual basis for the continued operation of the electric facilities of the Operating Companies to achieve the maximum possible economies consistent with the highest practicable reliability of service, and to provide a basis for equitably sharing the costs associated with the operation of facilities that are used for the mutual benefit of all the Operating Companies. Thus, the Operating Companies share all the benefits and burdens, including complying with operating, dispatch and reserve requirements, participating in opportunity sales transactions, and bearing responsibility for their portion of purchases.

Q DOES THE IIC ALSO PROVIDE A MECHANISM FOR REVIEWING GENERATION EXPANSION PLANS OF EACH OF THE OPERATING COMPANIES?

A Yes. Article IV of the IIC provides that a designated representative from each of the

Operating Companies, together with a representative of Southern Company Services, Inc., shall constitute as an "Operating Committee." The Operating Committee is responsible for reviewing and recommending generation expansion plans for approval by the Operating Companies that relate to the overall coordinated operation of the Southern electric system.

Q GPC ASSERTS THAT THE IIC PROVIDES A MECHANISM FOR TEMPORARILY SHARING CAPACITY SURPLUSES OR DEFICITS AMONG THE OPERATING COMPANIES. DOES THE IIC DEFINE A "TEMPORARY" CAPACITY SURPLUS OR DEFICIT?

A No. Under Section 7.1, the IIC is premised on each of the Operating Companies having adequate resources to reliably serve its own obligations. However, it also recognizes that in any given year one or more of the Operating Companies may have a temporary surplus or deficit of capacity as a result of coordinated planning or by virtue of load uncertainty, unit availability, and other such circumstances. Given the extraordinary nature of the growth that GPC is now incurring, the IIC should not have been so narrowly interpreted, as the Company is now suggesting.

Q DO THE OPERATING COMPANIES COMPENSATE ONE ANOTHER FOR THE COST OF CAPACITY THAT IS SHARED AMONG THEM?

A Yes. Section 7.2 of the IIC provides that the costs associated with reserve sharing capacity are settled on a monthly basis whereby each deficit company purchases capacity from a surplus company at the rate that reflects the cost of the most recently acquired peaking plant resource that is available for year-round operation and scheduling. Thus, while the IIC requires each Operating Company to be self-

sustaining, there is no stated limited on how often, or how long, an Operating Company can make reserve sharing purchases. Further, because generation expansion requires long lead times, and because capacity additions are "lumpy," there will always be some level of reserve sharing purchases and sales by and among the Operating Companies.

Q GPC ASSERTS THAT IT COULD NOT HAVE ACQUIRED CAPACITY FROM MPC THROUGH THE IIC AND THAT A SEPARATE PPA WAS ESSENTIAL. HAS GPC PROVIDED SUBSTANTIAL EVIDENCE TO SUPPORT THIS ASSERTION?

A No. First, under the IIC, the Operating Committee, in which GPC has a designated representative, annually reviews generation planning decisions. This would include both the timing and amount of any planned capacity additions and reassessing any prior decisions to retire generation capacity. Thus, when GPC became aware that MPC was planning to retire capacity that is now needed to maintain reliability for the Operating Companies, it could have arranged to procure this capacity through the IIC to assure that the resources would continue to be used and useful, while compensating MPC for the cost to keep the resources in operation.

Q DID MPC PROPOSE A RETIREMENT PLAN TO REDUCE 976 MW OF GENERATION CAPACITY BY YEAR-END 2027?

A Yes. MPC was ordered by the Commission to file a plan to retire approximately 950 MW of generation capacity by year-end 2027.[11] In 2021, MPC filed the proposed plan in its IRP. Table 2 summarizes MPC's proposed retirements from the 2021 IRP filing.

[11] *Mississippi Power Company's Reserve Margin Plan*, Docket No. 2018-AD-145, Order at 5-6 (Dec. 17, 2020).

Table 2 Mississippi Power Company Planned Capacity Retirements (MW)		
Generating Unit	**Net Capability**	**Planned Retirement**
Watson 4	268	Dec. 2023
Greene County 1	103	Dec. 2025
Greene County 2	103	Dec. 2026
MPC Daniel Coal	502	Dec. 2027
Total	976	
Source: Mississippi Power Company, MPSC Docket No. 2019-UA-231, 2021 IRP Filing at 4 (Apr. 15, 2021).		

Several facts about MPC's planned capacity retirements are noteworthy. First, the vast majority of the capacity would not have been retired until December 2027. Second, the Greene County Units are jointly owned by MPC (40%) and APC (60%).[12] As the majority owner, APC would have some say in the retirement decision. Third, despite the planned retirements, MPC was not projecting any capacity need until 2031 or later under the various planning scenarios considered (which also included the addition of BESS and utility-scale solar and higher carbon pressure scenarios).[13]

Q WHY WAS MPC ORDERED TO FILE A RETIREMENT PLAN?

A The Mississippi Public Service Commission was concerned that MPC not only had a capacity surplus until at least 2031, but a portion of MPC's fossil fuel fleet was

[12] *Mississippi Power Company's 2021 Integrated Resource Plan Filing*, Docket No. 2019-UA-231, Mississippi Power 2021 IRP Filing at 8-9 (Apr. 15, 2021).

[13] *Id*. at 4.

marginally economic.[14] These concerns are similar to the concerns discussed in GPC's 2022 IRP, which identified Plant Bowen and Plant Scherer as marginally economic.

Q WAS THE DECISION TO RETIRE 976 MW OF GENERATION CAPACITY IRREVOCABLE?

A No. The retirement plan filed by MPC in its 2021 IRP was in response to a Commission directive to either downsize MPC's generation fleet by no later than 2027 or to propose an alternative. However, an IRP is merely a blueprint — it is not an irrevocable action plan that will be executed regardless of the actual circumstances. To assert otherwise would be contrary to prudent system planning.

Further, even if certain plants are found to be marginally economic under certain specific circumstances, this finding alone is not a sufficient reason to irrevocably commit to retiring these resources. MPC could have marketed the capacity and generated revenues that effectively insulated retail customers from the economic costs of these resources. Thus, there was no reason to believe that MPC would have actually executed its retirement plan, especially if the capacity was needed elsewhere in the Southern Company system.

Q HOW DOES THE COST OF CAPACITY UNDER THE MPC PPA COMPARE WITH THE COST OF RESERVE SHARING UNDER THE IIC?

A In 2024, the cost of reserve sharing capacity is $73.20 per kW-year, which is equivalent to $6.10 per kW-month. This is shown in **Exhibit JP-3**, which is Schedule 3

[14] Docket No. 2018-AD-145, *Order* at 5-6 (Dec. 17, 2020).

from the 2024 IIC Informational Filing. By contrast, the capacity payment under the MPC PPA starts at $[redacted] per kW-month in 2024 and gradually escalates to $[redacted] per kW-month by 2028.[15] Thus, even before the $3 additional sum, the MPC PPA capacity payment is more expensive than an equivalent reserve sharing capacity purchase under the IIC.

Q WHAT DO YOU RECOMMEND?

A GPC could have procured capacity from MPC through the IIC, and the reserve sharing capacity price should have been a proxy for establishing a market-based capacity price. Paying more than the IIC price for capacity fails to maximize the benefits for GPC's retail customers. This is yet another reason for denying an additional sum on the MPC PPA.

[redacted] BESS/Solar Project

Q PLEASE DESCRIBE THE PROPOSED BATTERY AND SOLAR RESOURCES GPC IS PROPOSING TO PROCURE AS PART OF ITS IRP UPDATE PLAN.

A GPC's IRP update includes three new BESSs which would be paired with solar resources.[16] Two of these batteries, totaling 178 MW, would be installed at the sites of existing Company-owned solar facilities at the Robins and Moody Air Force Bases. However, there is currently no existing resource with which the third battery would be co-located. Thus, GPC is proposing to build a new 200 MW solar project to pair with this third battery, also sized to 200 MW. Collectively, this combined resource is referred to as the [redacted] BESS/Solar Project.

[15] Power Supply Agreement By and Between Mississippi Power Company and Georgia Power Company, Service Schedule at 4 (Oct. 11, 2023).

[16] 2023 IRP Update at 20.

Q HAS GPC CONSIDERED THE COSTS OF THE BESS RESOURCES IN AN ECONOMIC ANALYSIS?

A Yes. GPC conducted an economic analysis of the resources included in its IRP update. These results are summarized in Table 3 below.

Table 3
Summary of Updated Economic Analysis
Under MG0 Scenario
($/kW)

Project	Cost
Robins BESS	[redacted]
Moody BESS	
MPC PPA	
Santa Rosa PPA	
Yates 8–10 CTs	
[redacted] **BESS/Solar**	

Source: TS Updated Economic Analysis of Capacity Resources (Supplemental 1-12-24).

As Table 3 shows, the BESSs that would be installed at Robins and Moody Air Force Bases are among the least expensive resources included in GPC's IRP update. Conversely, the [redacted] BESS/Solar Project would be, by far, the most expensive resource included in GPC's portfolio. Specifically, GPC's projections show that [redacted] BESS/Solar Project would be [redacted]% more expensive than the Robins BESS and [redacted]% more expensive than the Moody BESS on a per kW basis.

Q ARE THE BATTERY RESOURCES INCLUDED IN GPC'S IRP UPDATE FUNDAMENTALLY SIMILAR?

A Yes. GPC has stated that the Robins and Moody BESSs will be based upon lithium-

ion technology.[17] Although GPC has not yet specified the technology for the proposed BESS at [redacted], lithium-ion technology is the prevalent technology type for utility-scale batteries. As such, it is reasonable to assume that this project will also utilize the same technology.

Q ASSUMING THAT THE BESS INCLUDED IN GPC'S IRP UPDATE ESSENTIALLY USES THE SAME TECHNOLOGY, WHAT IS THE DRIVER OF THE DRASTIC PRICE DIFFERENCES OBSERVED BETWEEN THE BESS RESOURCES IN GPC'S ECONOMIC ANALYSIS?

A Because the BESSs are fundamentally similar, the only difference observed between the Robins and Moody BESSs when compared to the [redacted] BESS that can account for the extreme price differences is the solar project that is proposed to be paired with the latter resource.

Q WHY IS GPC PROPOSING TO PAIR THE BATTERY AT THE [redacted] SITE WITH A SOLAR RESOURCE?

A GPC states that it is necessary to support the BESS with generating resources because they are limited by their discharge duration and need to be charged.[18] Consequently, GPC proposed to pair the [redacted] BESS with an accompanying solar resource. However, it also stated it could be charged by energy from the grid depending on the availability of firm transmission capacity.[19]

[17] Direct Testimony of Jeffrey R. Grubb, Francisco Valle, Lee Evans, and Michael A. Bush at 35.

[18] *Id*. at 39.

[19] *Id*. at 36.

Q IS IT REASONABLE FOR GPC TO ASSUME THAT A SOLAR RESOURCE IS THE ONLY OPTION WITH WHICH TO CHARGE THE PROPOSED [redacted] BESS?

A No, a paired solar resource is not the only method by which a BESS can be charged. As GPC recognizes, it is possible to charge a BESS with energy from the grid. In fact, the proposed solar project would be an extremely expensive way to charge the proposed BESS, as shown in Table 4 below.

Table 4
Comparison of [redacted] Solar Costs to GPC's Avoided Cost
($/MWh)

Year	[redacted] Solar	MG0	LG0	HG0	MG20	HG20	Average
2027	[redacted]						
2028							
2029							
2030							
2031							
2032							
2033							
2034							
2035							
2036							

Source: TS SAM ('23) – 7.0.1 – [redacted] BESS Final and TS STF-JKA-2-6 Attachment A.

Q PLEASE EXPLAIN TABLE 4.

A Table 4 compares the cost per MWh of the proposed [redacted] solar project with GPC's projected avoided cost under each of its planning scenarios for the first ten years of the project's operating life. The avoided cost under each planning scenario was calculated by averaging the hourly avoided cost for the hours from 5 a.m. to 7

p.m. for each day of the year to represent the hours when the sun is shining and a solar resource would presumably be operating.

As the table shows, the cost of the [redacted] solar project exceeds GPC's avoided cost under all planning scenarios from [redacted] through [redacted]. In subsequent years, the cost of the solar project is below GPC's avoided cost only under the HG20 scenario.

Q PLEASE SUMMARIZE YOUR FINDINGS REGARDING THE PROPOSED [redacted] BESS/SOLAR PROJECT.

A The [redacted] BESS/Solar Project is the most expensive project included in GPC's IRP update. Although the cost for the BESS component is comparable to that of other BESSs proposed, its high cost is driven by GPC's assumption that the BESS should be charged by a new, co-located solar project. Therefore, the [redacted] BESS would be more cost-effectively charged through energy from the grid rather than through a new solar resource.

Q WHAT DO YOU RECOMMEND?

A I recommend that if the Commission approves the [redacted] project, it should only do so for the individual BESS component. The solar component of the project should be rejected as it represents an extremely expensive option for charging the proposed BESS.

6. DISTRIBUTED ENERGY RESOURCE/DEMAND RESPONSE TARIFFS

Q OTHER THAN THE PREVIOUSLY DISCUSSED CAPACITY ADDITIONS, HOW IS GPC PROPOSING TO FILL THE PROJECTED CAPACITY NEED?

A GPC is proposing two new rate schedules to expand the installation of DERs and a new DR rate schedule. The three proposed DER/DR rate schedules are:

- DER Colocation Schedule: DCL-1;
- DER Customer Owned Schedule: DCO-1; and
- Curtailable Load Rider Schedule: CL-1.

Q PLEASE DISCUSS SCHEDULE DCL-1.

A Schedule DCL-1 would be applicable to "qualifying" commercial and industrial customers who agree to allow GPC to install a company-owned DER with a minimum nameplate capacity of 10 MW. The customer would be charged an unspecified rate based on the capital costs and operating expenses of the GPC-owned DER, in addition to paying for electricity used under the otherwise applicable rate schedule.

The DER would be dispatched solely by the Company, at its discretion, to provide system benefits. However, during times of electric service outage, the DER would be used to provide the participating customer with "resiliency" service to support the customer's operations. The term resiliency is not defined.

Further, as stated in the proposed schedule, the DER technology that may be utilized must be dispatchable, have a firm fuel supply, meet Company minimum technical requirements, and meet current regulatory requirements for non-emergency operation.

Q PLEASE DESCRIBE SCHEDULE DCO-1.

A Schedule DCO-1 is largely similar to DCL-1, except that the customer, rather than GPC, would provide the DER and related equipment. The customer would receive an unspecific credit based on the capital cost and operating expense of the DER, in addition to paying for electricity used under the otherwise applicable rate schedule.

However, the terms and conditions are more restrictive. For example, unlike Schedule DCL-1, the DER must have a minimum capacity of 1 MW and, citing potential operational risk, GPC is proposing to limit the size of a customer-owned DER to 10 MW.[20] The DER must also be newly manufactured and installed with a commercial operation date subsequent to the certification of the resources by the Commission.

Q PLEASE DESCRIBE SCHEDULE CL-1.

A Schedule CL-1 would be an alternative to the Demand Plus Energy Curtailment (DPEC) Schedule and would apply to customers who agree to reduce their load to a designated firm-demand level during periods of extreme supply and demand conditions (*i.e.*, a Demand Response Event) within no less than 30 minutes advance notice. A CL-1 customer would receive an unspecified credit based on 75% of the capacity value provided over the contract and identified in the customer agreement. Further, the demand credit would be fixed over the initial six-year term, but it would be updated during each subsequent annual renewal. However, either GPC or the customer may decline to renew the agreement.

[20] GPC Response to STF-PIA-9-3.

The customer would also be required to demonstrate its ability to curtail load each year and would be subject to substantial costs if it fails to comply during any Demand Response Event or demonstration.

Q ARE THERE ANY DESIGN ELEMENTS COMMON TO ALL THREE OF THE PROPOSED NEW SCHEDULES?

A Yes. In addition to not specifying the amount of the required credits/payments, GPC also reserves the right to terminate service in any related agreement without penalty or further obligation if:

- Termination is approved by the Commission;
- The participating customer fails to meet *any* obligations or requirements under the rate schedule or accompanying agreement; or
- Where termination is otherwise consistent with GPC's electric service Rules and Regulations.

Q DO YOU HAVE ANY CONCERNS WITH THE THREE PROPOSED NEW RATE SCHEDULES?

A Yes. GPC would have undue discretion in determining the amount of the credits/payments, renewal terms, penalties and other significant terms and conditions.

For example, the credits/payments would be based on "system value" as defined by GPC. Neither the term system value, nor the methodology for quantifying system value, is specified in any of the proposed new rate schedules. This would give GPC sole authority in determining the amount of the payments and/or credits and the customer would have no opportunity to either vet the proposed credits/payments or seek a remedy from the Commission. Without knowing the specific credit, or even the specific methodology and assumptions used in determining the credits, potential customers cannot properly assess the risks and benefits of opting for any of the

proposed new rate schedules. In essence, all the risks would be placed on the customers.

The risk-shifting is further exacerbated because GPC can terminate the DER/DR rate schedules without notice, and without further obligation, at its discretion. This is especially unfair because to the extent a customer is required to pay for DER facilities, or may require additional equipment to comply with curtailments under Schedule CL-1, premature termination with short or no notice could result in "stranding" the customer's investment.

Q DO YOU HAVE ANY SPECIFIC CONCERNS REGARDING PROPOSED SCHEDULE DCL-1?

A Yes. As previously stated, GPC will install, operate, maintain and control the Company-owned DER and related equipment as determined by GPC. All of the costs will be recovered in base rates, and GPC will earn a return on the associated rate base. However, there is no requirement for GPC to competitively procure the DER and related equipment to be installed at the premises of a participating customer, and the customer apparently has no input into the decision about the manufacturer and type of equipment to be installed at the customer's facility.

Q DO YOU HAVE ANY SPECIFIC CONCERNS REGARDING PROPOSED SCHEDULE DCO-1?

A Yes. First, as previously stated, GPC proposed limiting the maximum DER capacity to 10 MW, citing operational risk; whereas, there are no similar constraints in the proposed Schedule DCL-1. However, there are operating risks associated with any generation equipment, regardless of the operating party. Regardless of who will

own/operate the DER, the enabling agreement should provide a clear set of standards consistent with generally accepted operating and maintenance practices to ensure compliance. Further, GPC should be more than capable of conducting due diligence of a third-party owned and operated generator, including periodic inspections and operational reviews to minimize the risk of forced outages. Ultimately, the customer will have to demonstrate compliance with the Company's dispatch orders, or face either financial penalties or termination.

Second, although the customer is required to own and install the equipment and provide several capabilities, which include providing a firm fuel supply, the Company would have full operational control, including dispatching the resource solely at its discretion. It is unclear why any customer who may also require the thermal energy produced from the facility for heating/process use would be willing to give GPC full operational control without assurances that GPC cannot arbitrarily curtail the thermal energy supply.

Q DO YOU HAVE ANY SPECIFIC CONCERNS REGARDING PROPOSED SCHEDULE CL-1?

A Yes. First, the customer would be required to execute a six-year rolling term; that is, although the commitment will be renewed annually, unless GPC or the customer declines the renewal, the customer would have to wait for up to six years before returning to firm service. GPC has not explained why a six-year term is necessary or why a customer must wait six years to return to firm service. Second, it appears that GPC could penalize the customer for failing to comply with a curtailment based on a capacity value that could be higher than the credit that the Company is currently paying.

Third, the term Demand Response Event is not defined with any specificity. Although it is understandable that GPC will want to curtail load during extreme weather events, such as Winter Storm Elliot or the Polar Vortex, the circumstances in which GPC should call for curtailments should be defined more specifically. Examples of more specific circumstances requiring GPC to declare a Demand Response Event would include:

- Projected shortage of available generation and/or transmission capacity to maintain service to firm native load customers.
- Local area protection.
- System emergency.

Q WHAT DO YOU RECOMMEND?

A First, none of the three proposed new rate schedules should be approved as filed.

Second, GPC should be required to publicly disclose the methodology and assumptions for determining how any credits/payments under the rate schedules are determined and provide a specific quantification of the currently projected system resource (capacity/energy) values, at least annually, during the term of the corresponding agreements. Further, the methodology and assumptions should be subject to Commission review and approval, both initially and in each subsequent year. This would provide customers with sufficient information to assess their level of interest, prior to making a long-term commitment.

Third, customers should be given *at least* six months advance notice before service is terminated. Further, upon terminating any of the proposed rate schedules, GPC should be obligated to compensate the customer for any costs incurred to qualify for service under each rate schedule. This would require compensating the customer

for the remaining book-value of the equipment installed and paid for by the customer. This is only fair as GPC expects to be compensated when it retires a generating unit.

Q DO YOU HAVE ANY RECOMMENDED CHANGES TO SCHEDULE DCL-1?

A Yes. Generation is not a natural monopoly. Allowing a regulated monopoly to install generation behind a customer's meter at a discounted price to the customer while recovering the remaining costs, including a return on rate base, from its customer base would confer a competitive advantage over other (non-regulated) generation providers who do not have captive customers to recover their costs. To ensure that GPC does not disadvantage competitive generators, GPC should be required to competitively procure the DER and related equipment from third-parties. Further, the customer should be fully involved throughout the RFP process, including the preparation of the RFP, identifying qualified providers, evaluating the proposals, and selecting the winning bidder.

Q DO YOU HAVE RECOMMENDED CHANGES TO SCHEDULE DCO-1?

A Yes. Limiting Schedule DCO-1 to 10 MW is potentially anti-competitive. The customer should have the ability to reserve the right to utilize the DER facility to provide any needed thermal energy when the facility is being dispatched to serve system needs. Further, it should be clear that the customer will be allowed to outsource the design, build and fuel supply supporting the on-site DER provided, of course, that the customer is willing to certify that the equipment selection and the maintenance plan are consistent with generally accepted utility practice. Finally, GPC has not justified placing a 10 MW limit on the size of a customer-owned DER. To do so, would clearly discourage a customer from owning a DER in lieu of the Company ownership option,

thereby limiting competition. Thus, the Commission should reject the 10 MW limit. Alternatively, if the 10 MW limit is retained, then it should also apply to Schedule DCL-1.

Q DO YOU HAVE ANY PROPOSED CHANGES TO SCHEDULE CL-1?

A Yes. First, the specific circumstances that constitute a "Demand Response Event" should be identified (*e.g.*, a shortage of available generation and/or transmission capacity, area protection, or a system emergency). Second, the credit should reflect the full avoided cost of generation capacity. In the event that a Demand Response Event can occur due to shortages or congestion with the transmission system, the credit should also reflect avoided transmission capacity costs. The credit should not be discounted because to do so would underpay the customer and fail to recognize the benefit to firm customers who, as a result of increasing DR, will have more reliable service and less exposure to potentially costly outages.

Third, customers should have the option to choose among a menu of different options, such as contract duration and maximum daily/monthly/annual curtailment hours, and the credit should reflect the value of the option selected. For example, a longer contract term and/or more hours exposed to curtailments, should result in a higher credit. This would allow a customer to better align its appetite for risk with the potential benefits.

Finally, the compliance incentive should not exceed the capacity value reflected in the currently applicable agreement.

7. CONCLUSION

Q WHAT FINDINGS SHOULD THE COMMISSION MAKE BASED ON YOUR ASSESSMENT OF GPC'S IRP UPDATE?

A The Commission should make the following findings:

- Reject GPC's deferred accounting of capacity payments and development costs.
- Reject GPC's proposed additional sums on the MPC and Santa Rosa PPAs.
- Reject the proposed solar array at the [redacted] site.
- Reject the new DER/DR rate schedules (DCL-1, DCO-1, and CL-1) as proposed.
- Revise the DER/DR rate schedules to at a minimum:
  - Include a definition of system value.
  - Require GPC to seek Commission review and approval of the methodology and assumptions (by describing the methodology and providing a specific quantification) used to determine system value prior to approving the new rate schedules initially and in each subsequent year.
  - Require GPC to provide at least six months advance notice before any DER/DR rate schedule is discontinued and obligate GPC to compensate customers for any investments that become stranded as a result of program termination.
- Approve the following specific changes:
  - Allow customers on Schedule DCL-1 to be directly involved in competitively procuring the DER and related equipment.
  - Remove the 10 MW limit in DER capacity under Schedule DCO-1 to provide a clear set of standards, consistent with generally accepted utility practice, that the customer must comply with over the contract term, and ensure an uninterrupted supply of thermal energy to meet the customer's needs.

- Revise Schedule CL-1 to include a definition of Demand Response Event; reflect full avoided cost of capacity (including transmission if curtailments can occur due to shortages or congestion with the transmission system); the compliance incentive should not exceed the value of the credit; and customers should have a menu of options to choose from, such as longer/shorter contract duration and greater or fewer curtailment hours, and receive credits that appropriately reflect the capacity value of the selected options.

Q DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes.

APPENDIX A

Qualifications of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock. My business mailing address is 14323 South Outer 40, Suite 206N, Town and Country, Missouri 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Master's Degree in Business Administration from Washington University. I have also completed a Utility Finance and Accounting course.

Upon graduation in June 1975, I joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. From April 1995 to November 2004, I was a managing principal at Brubaker & Associates (BAI).

During my career, I have been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This includes preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost of service and rate design, tariff review and analysis, conducting site evaluations, advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing requests for proposals (RFPs), evaluating RFP responses and contract negotiation and developing and presenting seminars on electricity issues.

I have worked on various projects in 28 states and several Canadian provinces, and have testified before the Federal Energy Regulatory Commission, the Ontario Energy Board, and the state regulatory commissions of Alabama, Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Texas, Virginia, Washington, and Wyoming. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Board of Directors of the South Carolina Public Service Authority (a.k.a. Santee Cooper), the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.

A J. Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J. Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. J. Pollock is a registered broker and Class I aggregator in the State of Texas.

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	23-E-0418 23-G-0419	Direct	NY	Electric and Gas Embedded Cost of Service Studies; Class Revenue Allocation; Electric Customer Charge	11/21/2023
SOUTH CAROLINA PUBLIC SERVICE AUTHORITY	Industrial Customer Group	2023-154-E	Direct	SC	Integrated Resource Plan	9/22/2023
MIDAMERICAN ENERGY COMPANY	Google, LLC and Microsoft Corporation	RPU-2022-0001	Rehearing Rebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	9/8/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54634	Cross-Rebuttal	TX	Class Cost-of-Service Study; LGS-T Rate Design; Line Loss Study	8/25/2023
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-633-ER-23	Direct	WY	Retail Class Cost of Service and Rate Spread; Schedule Nos. 33, 46, 48T Rate Design; REC Tariff Proposal	8/14/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54634	Direct	TX	Revenue Requirement; Jurisdictional Cost Allocation; Class Cost-of-Service Study; Rate Design	8/4/2023
DUKE ENERGY CAROLINAS, LLC	Carolina Utility Customers Assocation, Inc.	E-7, Sub 1276	Direct	NC	Multi-Year Rate Plan; Class Revenue Allocation; Rate Design	7/19/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00286-UT	Direct	NM	Behind-the-Meter Generation; Class Cost-of-Service Study; Class Revenue Allocation; LGS-T Rate Design	4/21/2023
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44902	Direct	GA	FCR Rate; IFR Mechanism	4/14/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Stipulation Support	NM	Standby Service Rate Design	4/10/2023
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	53931	Direct	TX	Fuel Reconciliation	3/3/2023
NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC	RV Industry User's Group	45772	Cross-Answer	IN	Class Cost-of-Service Study; Class Revenue Allocation	2/16/2023
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Additional Testimony	IA	Application of Advance Ratemaking Principles to Wind Prime	2/13/2023
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	54234	Direct	TX	Interim Fuel Surcharge	1/24/2023
NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC	RV Industry User's Group	45772	Direct	IN	Class Cost-of-Service Study; Class Revenue Allocation	1/20/2023
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Surrebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	1/17/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54282	Direct	TX	Interm Net Surcharge for Under-Collected Fuel Costs	1/4/2023

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2022-254-E	Surrebuttal	SC	Allocation Method for Production and Transmission Plant and Related Expenses	12/22/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Surrebuttal	MN	Cost Allocation; Sales True-Up	12/6/2022
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2022-254-E	Direct	SC	Treatment of Curtailable Load; Allocation Methodology	12/1/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Rebuttal	NM	Standby Service Rate Design	11/22/2022
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Additional Direct & Rebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	11/21/2022
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	53719	Cross	TX	Retiring Plant Rate Rider	11/16/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Rebuttal	MN	Class Cost-of-Service Study; Distribution System Costs; Transmission System Costs; Class Revenue Allocation; C&I Demand Rate Design; Sales True-Up	11/8/2022
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	53719	Direct	TX	Depreciation Expense; HEB Backup Generators; Winter Storm URI; Class Cost-of-Service Study; Schedule IS; Schedule SMS	10/26/2022
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44280	Direct	GA	Alternate Rate Plan, Cost Recovery of Major Assets; Class Revenue Allocation; Other Tariff Terms and Conditions	10/20/2022
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320	Rebuttal	NY	COVID-19 Impact; Distribution Cost Allocation; Class Revenue Allocation; Firm Transportation Rate Design	10/18/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Direct	NM	Standby Service Rate Design	10/17/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Direct	MN	Class Cost-of-Service Study; Class Revenue Allocation; Multi-Year Rate Plan; Interim Rates; TOU Rate Design	10/3/2022
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320	Direct	NY	Electric and Gas Embedded Cost of Service Studies; Class Revenue Allocation; Rate Design	9/26/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00177-UT	Direct	NM	Renewable Portfolio Standard Incentive	9/26/2022

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by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
CENTERPOINT HOUSTON ELECTRIC LLC	Texas Industrial Energy Consumers	53442	Direct	TX	Mobile Generators	9/16/2022
ONCOR ELECTRIC DELIVERY COMPANY LLC	Texas Industrial Energy Consumers	53601	Cross-Rebuttal	TX	Class Cost-of-Service Study, Class Revenue Allocation; Distribution Energy Storage Resource	9/16/2022
ONCOR ELECTRIC DELIVERY COMPANY LLC	Texas Industrial Energy Consumers	53601	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Tariff Terms and Conditions	8/26/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	53034	Cross-Rebuttal	TX	Energy Loss Factors; Allocation of Eligible Fuel Expense; Allocation of Off-System Sales Margins	8/5/2022
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Direct	IA	Application of Advance Ratemaking Principles to Wind Prime	7/29/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	53034	Direct	TX	Allocation of Eligible Fuel Expense; Allocation of Winter Storm Uri	7/6/2022
AUSTIN ENERGY	Texas Industrial Energy Consumers	None	Cross-Rebuttal	TX	Allocation of Production Plant Costs; Energy Efficiency Fee Allocation	7/1/2022
AUSTIN ENERGY	Texas Industrial Energy Consumers	None	Direct	TX	Revenue Requirement; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/22/2022
DTE ELECTRIC COMPANY	Gerdau MacSteel, Inc.	U-20836	Direct	MI	Interruptible Supply Rider No. 10	5/19/2022
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44160	Direct	GA	CARES Program; Capacity Expansion Plan; Cost Recovery of Retired Plant; Additional Sum	5/6/2022
EL PASO ELECTRIC COMPANY	Freeport-McMoRan, Inc.	52195	Cross-Rebuttal	TX	Rate 38; Class Cost-of-Service Study; Revenue Allocation	11/19/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Supplemental	NM	Responding to Seventh Bench Request Order (Amended testimony filed on 11/15)	11/12/2021
EL PASO ELECTRIC COMPANY	Freeport-McMoRan, Inc.	52195	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate 15 Design	10/22/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Cross-Rebuttal	TX	Cost Allocation; Production Tax Credits; Radial Lines; Load Dispatching Expenses; Uncollectible Expense; Class Revenue Allocation; LGS-T Rate Design	9/14/2021
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	43838	Direct	GA	Vogtle Unit 3 Rate Increase	9/9/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	21-00172-UT	Direct	NM	RPS Financial Incentive	9/3/2021

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SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; LGS-T Rate Design	8/13/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Direct	TX	Schedule 11 Expenses; Jurisdictional Cost Allocation; Abandoned Generation Assets	8/13/2021
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51997	Direct	TX	Storm Restoration Cost Allocation and Rate Design	8/6/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Surrebuttal	PA	Class Cost-of-Service Study; Revenue Allocation	8/5/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Rebuttal	PA	Class Cost-of-Service Study; Revenue Allocation; Universal Service Costs	7/22/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Supplemental	NM	Settlement Support of Class Cost-of-Service Study; Rate Desgin; Revenue Requirement.	7/1/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Direct	PA	Class Cost-of-Service Study; Revenue Allocation	6/28/2021
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20940	Rebuttal	MI	Allocation of Uncollectible Expense	6/23/2021
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	20210015-EI	Direct	FL	Four-Year Rate Plan; Reserve Surplus; Solar Base Rate Adjustments; Class Cost-of-Service Study; Class Revenue Allocation; CILC/CDR Credits	6/21/2021
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-067-U	Surrebuttal	AR	Certificate of Environmental Compatibility and Public Need	6/17/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Rebuttal	NM	Rate Design	6/9/2021
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20940	Direct	MI	Class Cost-of-Service Study; Rate Design	6/3/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	51415	Supplemental Direct	TX	Retail Behind-The-Meter-Generation; Class Cost of Service Study; Class Revenue Allocation; LGS-T Rate Design; Time-of-Use Fuel Rate	5/17/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Direct	NM	Class Cost-of-Service Study; Class Revenue Allocation, LGS-T Rate Design, TOU Fuel Charge	5/17/2021
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-067-U	Direct	AR	Certificate of Environmental Compatibility and Public Need	5/6/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51625	Direct	TX	Fuel Factor Formula; Time Differentiated Costs; Time-of-Use Fuel Factor	4/5/2021

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SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	51415	Direct	TX	ATC Tracker, Behind-The-Meter Generation; Class Cost-of-Service Study; Class Revenue Allocation; Large Lighting and Power Rate Design; Synchronous Self-Generation Load Charge	3/31/2021
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51215	Direct	TX	Certificate of Convenience and Necessity for the Liberty County Solar Facility	3/5/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	50997	Cross Rebuttal	TX	Rate Case Expenses	1/28/2021
PPL ELECTRIC UTILITIES CORPORATION	PPL Industrial Customer Alliance	M-2020-3020824	Supplemental	PA	Energy Efficiency and Conservation Plan	1/27/2021
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	20-E-0428 / 20-G-0429	Rebuttal	NY	Distribution cost classification; revised Electric Embedded Cost-of-Service Study; revised Distribution Mains Study	1/22/2020
MIDAMERICAN ENERGY COMPANY	Tech Customers	EPB-2020-0156	Reply	IA	Emissions Plan	1/21/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	50997	Direct	TX	Disallowance of Unreasonable Mine Development Costs; Amortization of Mine Closure Costs; Imputed Capacity	1/7/2021
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	20-E-0428 / 20-G-0429	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Revenue Decoupling Mechanism	12/22/2020
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	20-E-0380 / 20-G-0381	Rebuttal	NY	AMI Cost Allocation Framework	12/16/2020
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51381	Direct	TX	Generation Cost Recovery Rider	12/8/2020
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	20-E-0380 / 20-G-0381	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Earnings Adjustment Mechanism; Advanced Metering Infrastructure Cost Allocation	11/25/2020
LUBBOCK POWER & LIGHT	Texas Industrial Energy Consumers	51100	Direct	TX	Test Year; Wholesale Transmission Cost of Service and Rate Design	11/6/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20889	Direct	MI	Scheduled Lives, Cost Allocation and Rate Design of Securitization Bonds	10/30/2020
CHEYENNE LIGHT, FUEL AND POWER COMPANY	HollyFrontier Cheyenne Refining LLC	20003-194-EM-20	Cross-Answer	WY	PCA Tariff	10/16/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00143	Direct	NM	RPS Incentives; Reassignment of non-jurisdictional PPAs	9/11/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-578-ER-20	Cross	WY	Time-of-Use period definitions; ECAM Tracking of Large Customer Pilot Programs	9/11/2020

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ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-578-ER-20	Direct	WY	Class Cost-of-Service Study; Time-of-Use period definitions; Interruptible Service and Real-Time Day Ahead Pricing pilot programs	8/7/2020
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	50790	Direct	TX	Hardin Facility Acquisition	7/27/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Surrebuttal	PA	Interruptible transportation tariff; Allocation of Distribution Mains; Universal Service and Energy Conservations; Gradualism	7/24/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Rebuttal	MI	Energy Weighting, Treatment of Interruptible Load; Allocation of Distribution Capacity Costs; Allocation of CVR Costs	7/14/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Rebuttal	PA	Distribution Main Allocation; Design Day Demand; Class Revenue Allocation; Balancing Provisions	7/13/2020
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2020-3019290	Rebuttal	PA	Network Integration Transmission Service Costs	7/9/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Direct	MI	Class Cost-of-Service Study;Financial Compensation Method; General Interruptible Service Credit	6/24/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/15/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Rebuttal	MI	Distribution Mains Classification and Allocation	5/5/2020
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	43011	Direct	GA	Fuel Cost Recovery Natural Gas Price Assumptions	5/1/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Direct	MI	Class Cost-of-Service Study; Transportation Rate Design; Gas Demand Response Pilot Program; Industry Association Dues	4/14/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	90000-144-XI-19	Direct	WY	Coal Retirement Studies and IRP Scenarios	4/1/2020
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20642	Direct	MI	Class Cost-of-Service Study; Class Revenue Allocation; Infrastructure Recovery Mechanism; Industry Association Dues	3/24/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Cross	TX	Radial Transmission Lines; Allocation of Transmission Costs; SPP Administrative Fees; Load Dispatching Expenses; Uncollectible Expense	3/10/2020

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SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00315-UT	Direct	NM	Time-Differentiated Fuel Factor	3/6/2020
SOUTHERN PIONEER ELECTRIC COMPANY	Western Kansas Industrial Electric Consumers	20-SPEE-169-RTS	Direct	KS	Class Revenue Allocation	3/2/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Direct	TX	Schedule 11 Expenses; Depreciation Expense (Rev. Req. Phase Testimony)	2/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Direct	TX	Class-Cost-of-Service Study; Class Revenue Allocation; Rate Design (Rate Design Phase Testimony)	2/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00134-UT	Direct	NM	Renewable Portfolio Standard Rider	2/5/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Settlement	NM	Settlement Support of Rate Design, Cost Allocation and Revenue Requirement	1/20/2020
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	49737	Direct	TX	Certificate of Convenience and Necessity	1/14/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Rebuttal	NM	Class Cost-of-Service Study; Class Revenue Allocation	12/20/2019
ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	32953	Direct	AL	Certificate of Convenience and Necessity	12/4/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Direct	NM	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	11/22/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49616	Cross	TX	Contest proposed changes in the Fuel Factor Formula	10/17/2019
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	42516	Direct	GA	Return on Equity; Capital Structure; Coal Combustion Residuals Recovery; Class Revenue Allocation; Rate Design	10/17/2019
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381	Rebuttal	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design	10/15/2019
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Amortization of Regulatory Liabilties; AMI Cost Allocation	9/20/2019
AEP TEXAS INC.	Texas Industrial Energy Consumers	49494	Cross-Rebuttal	TX	ERCOT 4CPs; Class Revenue Allocation; Customer Support Costs	8/13/2019
AEP TEXAS INC.	Texas Industrial Energy Consumers	49494	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Transmission Line Extensions	7/25/2019
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Cross-Rebuttal	TX	Class Cost-of-Service Study	6/19/2019

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CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Direct	TX	Class Cost-of-Service Study; Rate Design; Transmission Service Facilities Extensions	6/6/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	48973	Direct	TX	Prudence of Solar PPAs, Imputed Capacity, treatment of margins from Off-System Sales	5/21/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Rebuttal	MI	Classification of Distribution Mains; Allocation of Working Gas in Storage and Storage	4/29/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Direct	MI	Class Cost-of-Service Study; Transportation Rate Design	4/5/2019
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	49042	Cross-Rebuttal	TX	Transmsision Cost Recovery Factor	3/21/2019
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	49057	Direct	TX	Transmsision Cost Recovery Factor	3/18/2019
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2018-318-E	Direct	SC	Class Cost-of-Service Study, Class Revenue Allocation, LGS Rate Design, Depreciation Expense	3/4/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Settlement	AR	Testimony in Support of Settlement	3/1/2019
ENERGY+ INC.	Toyota Motor Manufacturing Canada	EB-2018-0028	Updated Evidence	ON	Class Cost-of-Service Study, Distribution and Standby Distribution Rate Design	2/15/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Surrebuttal	AR	Solar Energy Purchase Option Tariff	2/14/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	48847	Direct	TX	Fuel Factor Formulas	1/11/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Direct	AR	Solar Energy Purchase Option Tariff	1/10/2019

To access a downloadable list of Testimony filed from 1976 through the prior year, use this link: **J. Pollock Testimony filed from 1976 through the prior year**

Duke looks to add more gas, offshore wind to meet demand boom in NC, SC

Monday, February 5, 2024 3:48 PM CT

By Abbie Bennett
Platts

Projecting massive load growth in the Carolinas, Duke Energy Carolinas LLC and Duke Energy Progress LLC have amended resource plans to add more gas plants, advanced nuclear and wind.

"We're already projecting eight times the load growth we anticipated just two years ago," Duke North Carolina President Kendal Bowman and Duke South Carolina President Mike Callahan said in separate Jan. 31 statements.

The Duke Energy Corp. utility subsidiaries told state regulators in the Carolinas their load forecast through 2030 had increased by about 2 GW compared to the forecast used to develop prior plans.

That projected growth is due primarily to significant economic development planned in North Carolina and South Carolina, particularly manufacturing and technology, both industries that often "operate around the clock" and may require more on-demand energy resources, Duke Energy spokesperson Bill Norton told S&P Global Commodity Insights.

"This load growth is an industry-wide challenge — and the states that move decisively to build new generation will be best-positioned to take advantage of the positive trend in economic development opportunities while protecting affordability and reliability," Norton said.

North Carolina

In November 2023, Duke warned North Carolina regulators that "unprecedented economic development" well above the company's "historical experience" in the Carolinas was driving projected load growth across both states that "substantially exceeds even the high-load growth case" included in the company's resource plans filed in August 2023. The company reiterated those projections in its Jan. 31 filings.

To meet that growth, Duke proposed two large fossil gas plants, each at 1,360 MW, including at least one in Person County. The new gas plants would also be "hydrogen-capable," though that technology is not yet commercially available. Duke's proposed additions total nearly 9 GW of new gas before 2035, nearly tripling the gas generation proposed in its first carbon plan regulators approved in 2022.

"This plan is tripling down on the coal-to-gas transition, saddling customers with risky investments in new polluting power plants and failing to deliver the clean energy future called for in [North Carolina] state law," Will Scott, Southeast climate and clean energy director at the Environmental Defense Fund, said in a Feb. 1 statement. "We're hopeful the NC Utilities Commission will require Duke to pursue a path that controls costs for customers while meeting North Carolina's 2030 carbon emission reduction goal on time."

Duke's proposal also includes continued support for a new advanced nuclear facility in North Carolina, with an additional site to be determined in 2025.

"These breakthrough nuclear technologies are not anticipated to be available for deployment ... until the mid-2030s," Duke said in its filing.

Duke proposed 2,400 MW of wind generation offshore North Carolina by 2035 in its updated plan and 1,200 MW of new onshore wind for the Carolinas by 2033.

"Duke's updated modeling and supplemental portfolio clearly illustrates how important offshore wind will be to providing the large quantities of carbon-free electricity needed to reliably run the grid," Southeastern Wind Coalition President Katharine Kollins said. "Offshore wind is an incredible resource that will diversify power generation and provide electricity when we need it most — winter mornings and summer afternoons."

In North Carolina, Duke's newly amended plans include options for paths to 70% carbon emission reduction by 2030, 2033 and 2035. North Carolina state law mandates a 70% reduction in carbon pollution in the electric power sector by 2030.

North Carolina regulators ordered Duke to file with its updated plan a state-mandated portfolio that meets a 70% reduction in carbon emissions by 2030. Duke's preferred resource plan, however, targets a 70% reduction by 2035 or 2037. Offshore wind and advanced nuclear are key to reaching even those goals, Duke said.

That plan, according to the utility, would be the "most reasonable, least cost and least risk pathway to inform the near-term reasonable steps required to progress the reliable and orderly transition of the Carolinas system."

Future updates to North Carolina regulators will continue to include portfolio options targeting a 70% reduction by 2030, according to the law, Norton said.

A decision from the North Carolina Utilities Commission on the updated plan is expected by the end of 2024, according to Duke. Hearings for the plan are scheduled for spring and summer 2024.

South Carolina

South Carolina had the fastest-growing population in the US in 2023. To prepare for the load that will accompany future growth, Duke is proposing a new combined-cycle gas plant for South Carolina.

"This additional demand for energy is unprecedented — historic in both size and speed," Callahan said. "To meet customer needs, we're proposing more of nearly every resource available to us as we maintain our diverse 'all of the above' approach to maintain reliability and affordability."

The Carolinas plan includes advanced nuclear, gas, pumped hydro storage and renewables along with energy efficiency and demand-side management programs to target peak energy use reduction of nearly 2.8 GW by 2038, according to Duke.

At least one of several new gas plants Duke proposed is expected to be located in South Carolina.

Duke's amended Carolinas plans also include more solar energy than prior proposals, with a forecast for 17,500 MW of additional solar across both states within the next 15 years.

"We need power — a lot of it — and we need to take action today," Callahan said.

On Jan. 25, the South Carolina Public Service Commission approved Duke's proposal to provide additional information on its resource plan and reset the previously approved regulatory schedule. The new schedule now plans for a hearing in mid-September. Regulators are expected to decide on the plan as early as November.

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RATE SCHEDULE NO. 138

AMENDED AND RESTATED SOUTHERN COMPANY SYSTEM INTERCOMPANY INTERCHANGE CONTRACT

BETWEEN

ALABAMA POWER COMPANY, GEORGIA POWER COMPANY, MISSISSIPPI POWER COMPANY, SOUTHERN POWER COMPANY, AND SOUTHERN COMPANY SERVICES, INC.

Dated July 13, 2022

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AMENDED AND RESTATED
SOUTHERN COMPANY SYSTEM
INTERCOMPANY INTERCHANGE CONTRACT

ARTICLE I - RECITALS

Section 1.1: This contract is made and entered into as of July 13, 2022, by and between Alabama Power Company, a corporation organized and existing under the laws of the State of Alabama with its principal office in Birmingham, Alabama; Georgia Power Company, a corporation organized and existing under the laws of the State of Georgia with its principal office in Atlanta, Georgia; Mississippi Power Company, a corporation organized and existing under the laws of the State of Mississippi with its principal office in Gulfport, Mississippi; and Southern Power Company, a corporation organized and existing under the laws of the State of Delaware with its principal office in Birmingham, Alabama, all such companies being hereinafter collectively referred to as the "OPERATING COMPANIES"; and Southern Company Services, Inc., a subsidiary service company ("AGENT" or "SCS").

W I T N E S S E T H:

Section 1.2: WHEREAS, the common stock of the OPERATING COMPANIES is owned by The Southern Company, a public utility holding company; and

Section 1.3: WHEREAS, the OPERATING COMPANIES can be operated as an integrated electric utility system; and

Section 1.4: WHEREAS, the OPERATING COMPANIES have so operated their respective electric generating facilities and conducted their system operations (generally referred to as the "Pool") pursuant to and in accordance with the provisions of an interchange contract among

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themselves, the most recent of which being The Southern Company System Intercompany Interchange Contract dated February 17, 2000, as modified effective July 1, 2006 to reflect an intra-corporate reorganization ("the 2000 Contract"); and

Section 1.5: WHEREAS, the OPERATING COMPANIES desire to replace the 2000 Contract with an amended and restated contract; and

Section 1.6: WHEREAS, all of the OPERATING COMPANIES will continue to share in all of the benefits and burdens of this IIC, including complying with operating, dispatch and reserve requirements, participating in opportunity sales transactions, and bearing responsibility for their portion of purchases.

Section 1.7: NOW, THEREFORE, in consideration of the foregoing and the mutual covenants and agreements hereinafter stated, the OPERATING COMPANIES agree and contract as follows:

ARTICLE II - TERM OF CONTRACT

Section 2.1: This contract will be referred to as the Southern Company System Intercompany Interchange Contract ("IIC"). The IIC shall become effective as provided in Section 2.2 hereof, and shall continue in effect from year to year thereafter subject to termination as provided hereinafter. When this IIC has become effective, it shall supersede and replace the 2000 Contract, and references to a section of such superseded intercompany interchange contract in other agreements of the OPERATING COMPANIES shall be taken to mean reference to the section of substantially like import in this IIC.

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Section 2.2: This IIC was submitted as part of a filing in compliance with the orders of Federal Energy Regulatory Commission ("Commission" or "FERC") in Southern Company Services, Inc., Docket Nos. EL05-102, et al., 117 FERC ¶ 61,021 (2006) and Southern Company Services, Inc., Docket Nos. EL05-102, et al., 119 FERC ¶ 61,065 (2007). Pursuant to the Commission's acceptance of such compliance filing, this IIC is effective as of May 1, 2007.

Section 2.3: This IIC may be terminated at any time by mutual agreement of the OPERATING COMPANIES or may be terminated at any time by any OPERATING COMPANY by its giving to each of the other OPERATING COMPANIES and the AGENT written notice of its election to so terminate its participation in this IIC at least five (5) years prior to the date of termination. This IIC shall continue in full force and effect as to each OPERATING COMPANY until terminated as hereinabove provided.

ARTICLE III - PRINCIPAL OBJECTIVES OF INTERCOMPANY INTERCHANGE CONTRACT

Section 3.1: The purpose of this IIC is to provide the contractual basis for the continued operation of the electric facilities of the OPERATING COMPANIES in such a manner as to achieve the maximum possible economies consistent with the highest practicable reliability of service, with the reasonable utilization of natural resources and effect on the environment, and to provide a basis for equitably sharing among the OPERATING COMPANIES the costs associated with the operation of facilities that are used for the mutual benefit of all the OPERATING COMPANIES.

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Section 3.2: It is recognized that reliability of service and economy of operation require that the energy supply to the system be controlled by means of centralized economic dispatch and that this will require adequate communication facilities and the provision of economic dispatch computer facilities and automatic controls of generation.

Section 3.3: It is recognized that the IIC provides for the retention of lowest cost energy resources by each OPERATING COMPANY for its own customers. Energy in excess of that necessary to meet each OPERATING COMPANY's requirements is delivered to the Pool as Interchange Energy and may include: (i) energy generated from plants other than conventional hydro or nuclear; and (ii) purchased energy.

Section 3.4: It is recognized that, under this IIC, each OPERATING COMPANY will share in the benefits and pay its share of the costs of coordinated operations as agreed upon in accordance with the terms hereof. All costs and revenues associated with wholesale transactions under this IIC will be shared among all OPERATING COMPANIES on a comparable basis through the application of the governing procedures and methodologies to all such OPERATING COMPANIES.

Section 3.5: It is recognized by the OPERATING COMPANIES that coordinated electric operation contemplates minimum cost of power supply upon the interconnected system, consistent with service requirements and other operating limitations. Benefits of integrated operation accruing to the respective OPERATING COMPANIES are predicated upon cooperative efforts toward this objective and are so reflected in all IIC determinations.

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Section 3.6: This IIC is applicable only to the transactions described herein, as specifically set forth in ARTICLE VII – INTERCHANGE CAPACITY TRANSACTIONS BETWEEN THE OPERATING COMPANIES, ARTICLE VIII – INTERCHANGE ENERGY TRANSACTIONS BETWEEN THE OPERATING COMPANIES, and ARTICLE IX – PROVISION FOR OTHER INTERCHANGE TRANSACTIONS. Otherwise, sales between the OPERATING COMPANIES (including, but not limited to, sales from Southern Power Company to the other OPERATING COMPANIES or sales from the other OPERATING COMPANIES to Southern Power Company) require an appropriate filing under Section 205 of the Federal Power Act and acceptance thereof by the Commission.

ARTICLE IV - ESTABLISHMENT OF OPERATING COMMITTEE AND DESIGNATION OF AGENT

Section 4.1 – Establishment of Operating Committee: A designated representative from each of the OPERATING COMPANIES, together with a designated representative of the AGENT who shall act as chairman, shall form and constitute an Operating Committee to meet as needed to determine the methods of operation hereunder.

Section 4.2 – Duties of Operating Committee: The Operating Committee's areas of responsibility include such matters as developing the concepts, terms and conditions of this IIC; providing guidance and direction to the AGENT regarding economic power system operations and the costs associated therewith; reviewing and recommending generation expansion plans for approval by the respective OPERATING COMPANIES pursuant to Section 4.3; and addressing other power system matters that relate to the overall coordinated operation of the Southern

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electric system. Each OPERATING COMPANY representative has one vote and all decisions must be unanimous.

Section 4.3 – Review and Recommendation of Generation Expansion Plans: The Southern Power Company representative on the Operating Committee will not participate in reviewing and recommending generation expansion plans of the other OPERATING COMPANIES or the system, nor will the Southern Power Company representative have access to materials developed in conjunction with the formulation of such generation expansion plans. Notwithstanding Section 4.2 above, the Southern Power Company representative shall not be eligible to vote with respect to these expansion plans. Moreover, Southern Power Company will not receive market information from the other OPERATING COMPANIES through its participation in the Operating Committee.

Section 4.4 – Transmission Information: The Operating Committee does not have any duties or responsibilities with respect to transmission-related activities (including transmission reliability) and, consistent with the Standards of Conduct, will not receive non-public transmission information. The IIC (including Operating Committee membership) is not to serve as a means whereby non-public transmission information is shared in a manner contrary to the Commission's Standards of Conduct. Further, Southern Power Company is to be treated as an Energy Affiliate under the Commission's Standards of Conduct and therefore cannot receive any non-public transmission information.

Section 4.5 – Operating Committee Discretion: Certain provisions of the Manual afford a degree of latitude to the Operating Committee with regard to decisions that it is authorized to make

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thereunder. When such discretion is exercised, the AGENT will summarize the decision in an informational filing to be submitted to the Commission within ten (10) business days.

Section 4.6 – Designation of AGENT: SCS, as a party to this IIC, is designated as AGENT of the OPERATING COMPANIES for purposes of this IIC. In addition, SCS may serve as AGENT and represent the OPERATING COMPANIES, or any of them, in all things to be done in the execution of and operation under existing contracts with nonaffiliated utilities or entities (hereinafter referred to as "OTHERS"), or contracts supplemental thereto.

Section 4.7 – Duties of AGENT: The AGENT is responsible for all administrative and coordination functions in order to effectuate the terms and conditions of this IIC. From time to time, the OPERATING COMPANIES, or any of them, may also have contracts with OTHERS that provide for the purchase and/or sale of capacity and/or energy by the OPERATING COMPANIES. The AGENT will make the payments associated with purchases under these contracts and under any other contracts or arrangements under which it acts as agent for the OPERATING COMPANIES. Each OPERATING COMPANY will reimburse the AGENT for its portion of such total payments in accordance with the arrangement in effect with respect to the particular contract. Similarly, the AGENT will collect the payments due for sales under these contracts (and under any other contracts or arrangements under which it acts as agent) and will distribute such payments among the OPERATING COMPANIES in accordance with the arrangement in effect with respect to the particular contract.

Section 4.8 – Term of Agency: The provisions of this IIC providing for authority for the AGENT to act on behalf of the OPERATING COMPANIES, or any of them, shall be deemed to refer, insofar as applicable, to all contracts under which the AGENT acts as agent for the

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OPERATING COMPANIES and, notwithstanding anything to the contrary in ARTICLE II hereof, this IIC shall continue in effect insofar as it pertains to other contracts under which the AGENT acts as agent for the OPERATING COMPANIES during the life of any such contracts. The OPERATING COMPANIES may, however, designate a new agent to act hereunder by giving thirty (30) days written notice thereof to the AGENT, whereupon such new agent shall be the AGENT hereunder.

ARTICLE V - OPERATION AND MAINTENANCE OF ELECTRIC GENERATING FACILITIES

Section 5.1: The OPERATING COMPANIES agree to maintain their respective electric generating facilities in good operating condition and to operate such facilities in coordination with those of the other OPERATING COMPANIES as an integrated electric system in accordance with determinations made from time to time by the Operating Committee in order that an adequate power supply shall be available to meet the requirements of the customers of the respective parties hereto at the lowest cost consistent with a high degree of service reliability.

Section 5.2: With respect to its participation in this IIC, Southern Power Company may have access to information regarding the operation of its own plants or other generation resources (such as those acquired by contract) that it has committed to the Pool ("Pool resources"), but it may not otherwise have access to information regarding the operation of Pool resources of the other OPERATING COMPANIES.

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ARTICLE VI - INCORPORATION OF THE ALLOCATION METHODOLOGY AND PERIODIC RATE COMPUTATION MANUAL

Section 6.1 – Incorporation of Manual: The mechanics and methods for determining the charges for reserve sharing capacity and for energy purchased and sold between the OPERATING COMPANIES, the monthly capability requirement determinations, and the monthly billings and payments between the OPERATING COMPANIES are described in detail in the Allocation Methodology and Periodic Rate Computation Manual ("Manual") attached hereto and incorporated herein by reference. The Manual also supplies more detailed explanation of provisions of this IIC and is necessary to effectuate its intent.

Section 6.2 – Purpose of Manual: The Manual contains a description of the methodology and procedure used to calculate the charges provided for in this IIC. The OPERATING COMPANIES recognize that the costs underlying these charges will change during the term of this IIC for reasons such as changes in loads, investment and expenses, as well as the addition of electric generating resources. Thus, in order for the OPERATING COMPANIES to share equitably in the costs associated with this IIC, it will be necessary to revise or update, on a periodic basis, the cost, expense, load and investment figures utilized in the derivation of the charges hereunder. The Manual will serve as a formula rate allowing for periodic revision of the charges to reflect changes in the underlying cost components.

Section 6.3 – Revision of Charges and Regulatory Filings: The Manual provides that charges derived by application of the formula rate will be shown on Informational Schedules. Since the charges under this IIC will be computed in accordance with the formula rate method and procedures established in the Manual, these submissions will not be initial rates or changes in rates that would require a filing and suspension under the Federal Power Act and the applicable

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Rules and Regulations of the Commission. On or before November 1 of each year, the Informational Schedules will be submitted to the Commission for informational purposes to show the application of the formula rate and the resulting charges. Work papers will also be included showing a detailed application of the formula rate contained in the Manual.

Section 6.4 – Revision of Manual: If the Operating Committee determines that revisions to the formula rate are appropriate or necessary, it will direct the AGENT to file the revised Manual with the Commission in order to obtain timely approval or acceptance thereof.

ARTICLE VII - INTERCHANGE CAPACITY TRANSACTIONS BETWEEN THE OPERATING COMPANIES

Section 7.1 – Provision for Sharing of Temporary Surpluses or Deficits of Capacity Between Operating Companies: It is a fundamental premise of this IIC that each OPERATING COMPANY is expected to have adequate resources to reliably serve its own obligations. Nevertheless, the OPERATING COMPANIES recognize that in any given year one or more of them may have a temporary surplus or deficit of capacity as a result of coordinated planning or by virtue of load uncertainty, unit availability, and other such circumstances. It is among the purposes of this IIC to share among the OPERATING COMPANIES the benefits and burdens of their coordinated system operations, including the cost associated with such capacity ("Reserve Sharing"). Reserve Sharing among the OPERATING COMPANIES is accomplished pursuant to transactions (referred to as "purchases" and "sales") effectuated on a monthly basis in accordance with ARTICLES IV and V of the Manual.

Section 7.2 – Charge for Monthly Reserve Sharing Among the OPERATING COMPANIES: The OPERATING COMPANIES recognize that capacity reserves in the Pool are predominantly

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made up of peaking plant or equivalent purchased resources. Accordingly, the monthly charge for Reserve Sharing among the OPERATING COMPANIES will be based on the most recently acquired peaking plant resource that is available for year-round operation and scheduling. Each OPERATING COMPANY's monthly charge for reserve capacity sold to the Pool is developed in accordance with the formula rate set out in ARTICLE V of the Manual. The monthly capacity charge for each OPERATING COMPANY, as developed in accordance with such formula rate, will be shown on Informational Schedules. Each selling OPERATING COMPANY will sell at its charge shown on such Informational Schedules and the buying OPERATING COMPANIES will purchase at the weighted average charge of the sellers.

ARTICLE VIII - INTERCHANGE ENERGY TRANSACTIONS BETWEEN THE OPERATING COMPANIES

Section 8.1 – Provision for Interchange Energy: Coordinated system operation, utilizing principles of centralized integrated system economic dispatch, results in energy transfers among the OPERATING COMPANIES. Such energy transfers are accounted for on an hourly basis and are referred to as "Interchange Energy." The methodology for determining the amount of Interchange Energy supplied to or purchased from the Pool is set out in ARTICLE II of the Manual. Interchange Energy is composed of the following two categories: (i) Associated Interchange Energy (energy purchased or sold to serve an OPERATING COMPANY's obligations other than those related to opportunity sales); and (ii) Opportunity Interchange Energy (energy purchased or sold to meet an OPERATING COMPANY's responsibility for opportunity sales).

Section 8.2 – Charge for Interchange Energy: The charge for Interchange Energy sales by an OPERATING COMPANY during any hour will be based on the variable costs of the generating

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resources that are considered as having supplied the Interchange Energy. The methodology for determining the charges for Associated and Opportunity Interchange Energy sales to the Pool during any hour is set out in ARTICLE III of the Manual.

ARTICLE IX - PROVISION FOR OTHER INTERCHANGE TRANSACTIONS

Section 9.1 – Assignable Energy: Assignable Energy is defined as energy derived from internal sources or from OTHERS at a cost that renders it unusable from an economic dispatch perspective. Assignable Energy is assigned to one or more of the OPERATING COMPANIES consistent with the purpose for which it is acquired. Such assignment will be accomplished by first identifying the beneficiary (or beneficiaries) of the Assignable Energy and then determining the appropriate share for each such OPERATING COMPANY. For example, these shares might be based on a Peak Period Load Ratio ("PPLR") in proportion to the PPLRs of other beneficiaries or weighted participation in a bilateral sale. Once assigned, Assignable Energy will not be delivered to the Pool unless it becomes economically usable on the integrated system.

Section 9.2 – Hydroelectric Operation During Periods of Minimum Steam Operations: During certain periods of the year when unusually good flow conditions prevail, certain steam generating units may be taken out of service to increase the utilization of hydro energy. The OPERATING COMPANY having such hydro generation may elect to take a fossil fired generating unit out of service. In the alternative, if another OPERATING COMPANY takes a fossil fired generating unit out of service for the purpose of utilizing such hydro energy, the energy rate between the two OPERATING COMPANIES for that transaction will be the average of the operation and maintenance cost of such hydro energy and the variable cost of the fossil fired generating unit.

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Section 9.3 – Tie-Line Frequency Regulation by Hydro Capacity: Tie-line load control and frequency regulation by hydro involves additional costs because of increased expenditures associated with such regulation. The charge for these transactions is computed in accordance with the formula rate contained in ARTICLE VI of the Manual.

Section 9.4 – Pool Transactions with OTHERS: Capacity and energy transactions with OTHERS that are entered into on behalf of the Pool will be governed by the following principles:

Section 9.4.1 – Pool Purchases of Capacity and Energy: The AGENT may periodically purchase capacity and energy from OTHERS for the benefit of the integrated system. Such Pool purchases will initially be allocated at cost to all OPERATING COMPANIES in proportion to their PPLRs, as provided for in ARTICLE X of this IIC. Purchases so allocated may be sold as Interchange Energy when they are economically usable on the integrated system. Adjustments may thereafter be made in order to reconcile any inequitable effects of this process among the OPERATING COMPANIES, with the intent being that none of the individual OPERATING COMPANIES should be adversely impacted by a purchase that benefits the system as a whole. These impacts will be determined through a system simulation that calculates each OPERATING COMPANY's cost of generation that is avoided by the purchase. This avoided cost will be compared on an hourly basis to the cost of the purchase. To the extent the avoided cost exceeds the purchase cost, the effect is "positive" (i.e., cost savings) for that hour. These hourly results will be summed to determine the effect on each OPERATING COMPANY for the day. In situations where individual OPERATING COMPANIES are adversely impacted by a purchase that benefits the system as a whole, such adverse impacts will be offset through a proportional

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reduction in the positive net benefits realized by the other OPERATING COMPANIES. In the event the net result for the day is negative, that result is shared among the OPERATING COMPANIES on a PPLR basis.

Section 9.4.2 – Pool Sales of Capacity and Energy: The AGENT may from time to time arrange for the sale to OTHERS of capacity and energy available to the Pool at rates provided for in contracts or at rates mutually agreed upon. The capacity and/or energy obligation for the sale, as well as the associated cost, is allocated to each OPERATING COMPANY on a PPLR basis. Payments by OTHERS are also distributed to the respective OPERATING COMPANIES on the basis of PPLRs.

The Pool has the exclusive right to use generation resources committed to the Pool ("Pool resources") to engage in opportunity transactions with OTHERS that would begin and end during the period from the current hour through Friday (midnight) of the following week. Neither Southern Power Company nor any of the other OPERATING COMPANIES can use Pool resources for its own benefit in those wholesale opportunity markets. To the extent Southern Power Company engages in other transactions solely for its own benefit, it must do so using personnel (staff) separate from the personnel (staff) that conducts similar activities on behalf of the other OPERATING COMPANIES.

ARTICLE X – UTILIZATION OF PEAK-PERIOD LOAD RATIOS

Section 10.1 – Certain Allocations and Payments to be Based on Peak-Period Load Ratios: The AGENT is responsible for the annual development of Peak-Period Load Ratios ("PPLRs") for each of the OPERATING COMPANIES. These PPLRs will be utilized for allocation of certain costs, payments, receipts and other obligations, as provided for in this IIC or the Manual. The

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procedure and methodology for developing the PPLRs are set out in ARTICLE I of the Manual and the resulting PPLR values are shown on an Informational Schedule.

ARTICLE XI - TRANSMISSION SERVICE

Section 11.1 – Applicability of Network Integration Transmission Service: Network Integration Transmission Service ("Network Service") provides for the integration, economic dispatch and regulation of current and planned Network Resources to serve Network Load. Since the OPERATING COMPANIES integrate, economically dispatch and regulate their generating resources to serve their bundled and grandfathered native load ("Native Load") pursuant to this IIC, the associated use of the transmission system is in the nature of Network Service. Except for provisions related to rates and charges, the transmission service provided to these Native Load customers is comparable to Network Service under the Open Access Transmission Tariff ("OATT"). Since the OPERATING COMPANIES' Native Load is specifically included in the determination of the load used to derive the charge for Network Service under the OATT, the OPERATING COMPANIES are bearing a cost responsibility for transactions hereunder comparable to that assigned to other Network Customers.

Section 11.2 – Transmission Service for Other Transactions: All transmission service provided to any or all of the OPERATING COMPANIES (other than service to their Native Load, as described in Section 11.1) is subject to the OATT in all respects, including adherence to the same rates, terms and conditions applicable to other market participants. Any such transmission service will be obtained pursuant to the OATT and/or from other transmission providers.

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Southern Power Company specifically commits to take all of its transmission service under the OATT of Southern Companies or from other transmission providers.

ARTICLE XII - BILLING AND PAYMENT

Section 12.1 – Recording and Billing of Energy Transactions: Each OPERATING COMPANY will transmit to the AGENT such data and other information for each hour of the year as is necessary to develop accounting and monthly billing for the various energy transactions specified under this IIC. The AGENT is responsible for assembling all of the data and information and for preparing intercompany energy billing for each month in accordance with the provisions of this IIC. The bills shall contain such details as required to permit review and verification by the OPERATING COMPANIES.

Section 12.2 – Month-End Adjustment of Daily Energy Determinations: It is recognized that the sum of the daily totals of receipts and deliveries (which are based on instantaneous integrated meters) will not exactly equal corresponding amounts determined at month-end (which are based on accumulating meters). Such differences in energy receipts and deliveries are billed or credited to each OPERATING COMPANY at the average cost of Associated Interchange Energy to the Pool for the month.

Section 12.3 – Billing for Reserve Sharing Transactions: The AGENT is responsible for preparing a monthly bill to the OPERATING COMPANIES for all capacity transactions related to Reserve Sharing, as contemplated by this IIC. The bill shall contain such details as required to permit review and verification by the OPERATING COMPANIES.

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Section 12.4 – Billing and Payment Date: The AGENT renders all bills provided for in this IIC not later than the 10th day of the billing month. All payments by the OPERATING COMPANIES are made by the 20th day of the billing month.

Section 12.5 – Billing Corrections: If the AGENT discovers missing or erroneous data of a material nature pertaining to prior billings, a correction adjustment applicable to those billings will be based on the period affected by such missing or erroneous data, but not to exceed forty-five (45) days from the date of such discovery ("correction period"). If the correction period is forty-five days, then the period actually used for the calculation will extend to the beginning of the billing month in which the forty-five day period falls. Interest does not accrue on any such adjustment. The resulting billing correction will be applied as soon as practicable to the regular monthly bill.

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IN WITNESS WHEREOF, the parties hereto have caused this instrument to be signed by their duly authorized representatives on the Operating Committee, which signatures may be set forth on separate counterpart pages.

ALABAMA POWER COMPANY

By: DocuSigned by: Jim P. Heilbron
5D07C7F70B6E4CF...
Jim P. Heilbron
Its Senior Vice President & SPO-West

MISSISSIPPI POWER COMPANY

By: DocuSigned by: Michael W. Smith
13BA90BBBE0C42A...
Michael W. Smith
Its Vice President & SPO

GEORGIA POWER COMPANY

By: DocuSigned by: R Allen Reaves
33A36C6B17A4A0...
R. Allen Reaves
Its Senior Vice President & SPO-East

SOUTHERN POWER COMPANY

By: DocuSigned by: DANA P CLABURN
ABDCBAD286204FF...
Dana P. Claburn
Its Senior Vice President & SPO

SOUTHERN COMPANY SERVICES, INC.

By: DocuSigned by: Scott Teel
2EEA94D0EECB48E...
Scott Teel
Its Senior Vice President-Commercial Operations

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ALLOCATION METHODOLOGY AND PERIODIC RATE COMPUTATION PROCEDURE MANUAL

Section 0.0 – Description and Purpose of Manual: This Manual is provided for in the Southern Company System Intercompany Interchange Contract ("IIC") entered into the 1st day of May, 2007, and contains a formula description of the methodology and procedure used to calculate the charges under the IIC. The Manual is divided into six (6) basic articles as follows:

ARTICLE I	-	Methodology for Determination of Peak-Period Load Ratios
ARTICLE II	-	Methodology for Determination of Amount of Interchange Energy Sold To and Purchased From the Pool
ARTICLE III	-	Rates for Interchange Energy
ARTICLE IV	-	Methodology for Determination of Monthly Amount of Reserve Sharing Capacity To Be Sold To or Purchased From the Pool
ARTICLE V	-	Rate for Monthly Reserve Sharing Capacity for Each Operating Company
ARTICLE VI	-	Rate for Tie-Line Load Control and Frequency Regulation by Hydro Facilities

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ARTICLE I

METHODOLOGY FOR DETERMINATION OF PEAK-PERIOD LOAD RATIOS

Section 1.1 – Provision for Peak-Period Load Ratios: This article of the Manual establishes and provides for the annual derivation of Peak-Period Load Ratios ("PPLRs") that are utilized in energy and capacity transactions and in other allocations as provided for in the IIC. These ratios are shown on Informational Schedule No. 1.

Section 1.2 – Methodology for Determining Peak-Period Load Ratios: The Contract Year in the IIC is defined as January 1st through December 31st. The peak period is defined as the fourteen (14) hours between 7:00 a.m. and 9:00 p.m. (Prevailing Central Time) of each weekday, excluding holidays.

The Peak-Period Load Ratios for the Contract Year are based upon the prior year's actual peak period energy in the months of June, July, and August for each OPERATING COMPANY. The system peak period energy is equal to the sum of all the OPERATING COMPANIES' peak period energy, excluding: (i) opportunity transactions with OTHERS that would begin and end during the period from the current hour through Friday (midnight) of the following week; and (ii) any energy sales transactions that are settled on a financial basis.

The Peak-Period Load Ratios are determined by dividing each OPERATING COMPANY's summation of the June, July, and August actual weekday peak-period energy by the total system June, July, and August actual weekday peak-period energy.

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ARTICLE II

METHODOLOGY FOR DETERMINATION OF AMOUNT OF INTERCHANGE ENERGY SOLD TO AND PURCHASED FROM THE POOL

Section 2.1 – Methodology for Determination of Amounts of Interchange Energy: Interchange Energy is composed of the following two categories: (i) Associated Interchange Energy (energy purchased or sold to serve an OPERATING COMPANY's obligations other than those related to opportunity sales); and (ii) Opportunity Interchange Energy (energy purchased or sold to meet an OPERATING COMPANY's responsibility for opportunity sales).

Section 2.1.1 – Determination of Associated Interchange Energy: The amount of Associated Interchange Energy purchased or sold is computed hourly on the basis of the following:

1. Net receipts and deliveries, which is the total of energy delivered by each OPERATING COMPANY to all other OPERATING COMPANIES and to OTHERS, less the total of energy received by each OPERATING COMPANY from all other OPERATING COMPANIES and from OTHERS;

2. Adjustments for schedules of the OPERATING COMPANIES and OTHERS, for energy movements received from or delivered to sources within or outside the territory of the OPERATING COMPANIES and settled for under arrangements made for such energy movements;

3. Adjustments for Opportunity Interchange Energy, as determined pursuant to Section 2.1.2 below; and

4. Adjustments to account for: (i) the effects of remote generation to which an OPERATING COMPANY is entitled and remote load for which an OPERATING COMPANY is responsible; and (ii) hydro energy losses due to tie-line frequency regulation.

Section 2.1.2 – Determination of Opportunity Interchange Energy: The amount of Opportunity Interchange Energy purchased or sold is computed hourly for each opportunity sale in order to account for the difference between an OPERATING COMPANY's responsibility for

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an opportunity sale and the amount of energy actually generated by that OPERATING COMPANY in connection with such sale.

ARTICLE III
RATES FOR INTERCHANGE ENERGY

Section 3.1 – Procedure for Economic Dispatch: Centralized economic dispatch is accomplished by dispatching system generating resources and purchases to meet the obligations of the OPERATING COMPANIES and to supply energy for sales to OTHERS. System generating resources are dispatched based on marginal replacement fuel cost, variable operation and maintenance expenses, in-plant fuel handling costs, emission allowance replacement costs, compensation for transmission losses, and other such energy related costs that would otherwise not have been incurred. A purchase is recognized in economic dispatch on the basis of its energy cost. The above-referenced cost components are collectively referred to as the "variable dispatch cost."

Section 3.2 – Associated Interchange Energy Rate: The Associated Interchange Energy Rate, as determined for each hour, is based on the variable dispatch cost of the incremental resource(s) that serve the collective obligations of the OPERATING COMPANIES. For each hour, an OPERATING COMPANY supplying Associated Interchange Energy to the Pool will receive a payment determined by multiplying the applicable Associated Interchange Energy Rate by the quantity of kilowatt-hours sold to the Pool. For each hour, an OPERATING COMPANY purchasing Associated Interchange Energy from the Pool will be charged an amount determined by multiplying the Associated Interchange Energy Rate by the quantity of kilowatt-hours purchased from the Pool.

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Section 3.3 – Opportunity Interchange Energy Rate: The Opportunity Interchange Energy Rate, as determined for each hour, is based on the variable dispatch cost of the resources that supplied such energy in connection with a given opportunity sale. This rate will be applied to each OPERATING COMPANY's energy obligation for that transaction to derive the payment due from such OPERATING COMPANY. The resulting payments will then be used to reimburse the cost of the OPERATING COMPANIES that supplied the Opportunity Interchange Energy.

Section 3.3.1 – Opportunity Interchange Energy Rates Related to Certain Contracts and Other Obligations of the Operating Companies: The OPERATING COMPANIES are currently obligated to supply various types of energy under certain contracts with Florida Power & Light Company, Jacksonville Electric Authority, Florida Power Corporation, and South Mississippi Electric Power Association. For purposes of these contracts, the variable dispatch cost of resources supplying the energy shall be the same as described in Section 3.1 of the Manual, except that blended replacement fuel cost will be used instead of marginal replacement fuel cost.

Section 3.4 – Variable Operation and Maintenance Expenses For Fossil Fired Units: The variable Operation and Maintenance expenses for fossil fired units for the Contract Year are derived by summing the following budgeted/forecasted components for each unit: (i) all operating material, non-labor, and on-site contract labor charged to FERC Accounts 502 and 505 (Fossil Steam); and (ii) all maintenance material, non-labor, and contract labor charged to FERC Accounts 512 and 513 (Fossil Steam), and 553 (Combustion Turbine). These budgeted expense estimates may be levelized over the major maintenance cycle of a particular unit or set of units. The estimated expenses are divided by the estimated net energy output of each unit to convert the

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values to dollars per megawatt-hour. The variable Operation and Maintenance expense for each fossil fired unit is shown on Informational Schedule No. 2 for the Contract Year.

Section 3.4.1 – In-Plant Fuel Handling Costs for Fossil Fired Units: In-Plant fuel handling costs for each fossil fired unit for the Contract Year are based on the budgeted/forecasted expenditures for in-plant fuel handling expenses charged to FERC Account 501. These budgeted expense estimates may be levelized over the major maintenance cycle of a particular unit or set of units. The estimated expenses are divided by the estimated net energy output of each unit to convert the values to dollars per megawatt-hour. The in-plant fuel handling cost for each fossil fired unit is shown on Informational Schedule No. 2 for the Contract Year.

Section 3.5 – Blended Replacement Fuel Cost: Blended replacement fuel costs are determined monthly by the AGENT and are defined as the weighted average cost, escalated for the current dispatch period, of fuel receipts for the previous month (both long-term contract and spot market receipts) and the projected fuel receipts for the current month.

Section 3.6 – Marginal Replacement Fuel Cost: Marginal replacement fuel costs for coal are determined at least monthly by the AGENT and reflect the current market price for additional coal needed at a generating facility at the time of such need. For natural gas or oil-fired units, the marginal replacement fuel costs are updated each business day based upon next day market prices.

Section 3.7 – Emission Allowance Replacement Costs: The replacement costs of emission allowances are determined at least monthly by the AGENT and reflect the current market value of such allowances.

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Section 3.8 – Revisions in Methodologies: The procedures described in Sections 3.6 and 3.7 will be periodically reviewed by the AGENT and may be revised upon the approval of the Operating Committee.

ARTICLE IV

METHODOLOGY FOR DETERMINATION OF MONTHLY AMOUNT OF RESERVE SHARING CAPACITY TO BE SOLD TO OR PURCHASED FROM THE POOL

Section 4.1 – Formula for Determination of Monthly Reserve Sharing Capacity Sales/Purchases: The monthly capacity sale to or purchase from the Pool for each OPERATING COMPANY for reserve sharing purposes is determined from the following formula:

CS or CP = RS - R

Where:

CS or CP = Capacity sales to the Pool (CS) or capacity purchases from the Pool (CP) by an OPERATING COMPANY for reserve sharing purposes. A negative value indicates a sale to the Pool and a positive value indicates a purchase from the Pool.

RS = Reserve responsibility for each OPERATING COMPANY (See Section 4.1.1).

R = Reserve capacity for each OPERATING COMPANY (See Section 4.1.2).

Section 4.1.1 – Reserve Responsibility (RS): The responsibility for the reserve capacity on the integrated electric system is allocated among the OPERATING COMPANIES on the basis of peak hour load ratios for each month.

RS = L/L' x R

Where:

RS = Reserve responsibility for each OPERATING COMPANY.

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L = Monthly peak hour load responsibility of each OPERATING COMPANY (See Section 4.3).

L' = Monthly peak hour load of the integrated electric system (See Section 4.3).

R = Sum of the reserve capacity for all of the OPERATING COMPANIES.

Section 4.1.2 – Reserve Capacity (R): The reserve capacity for each of the respective OPERATING COMPANIES is determined monthly by the following formula:

R = C - CR

Where:

C = Total capacity available to the OPERATING COMPANY (See Section 4.2).

CR = Total capacity required to meet reliably the OPERATING COMPANY's load responsibility.

The capacity required to meet the OPERATING COMPANY's load responsibility is determined by the following formula:

CR = LC + LCR

Where:

LC = Portion of the total capacity required to meet reliably the OPERATING COMPANY's load responsibility that is available for load service ("available portion").

LCR = Portion of the capacity required to meet reliably the OPERATING COMPANY's load responsibility that is unavailable for load service for any reason (including forced outage, partial outage or maintenance outage) during the ten (10) highest system peak hours during each month averaged over the most recent three-year period ("unavailable portion"). These unavailable portions of capacity are determined by identifying unavailability specific to each individual OPERATING COMPANY by each generation type. Individual OPERATING COMPANY unavailability factors for each type of

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generating capacity will be applied to their respective owned resources in determining their unavailable capacity associated with load service.

The available portion of the total capacity is determined from the following formula:

LC = RPS + DSO + Cha + Cna + Coa

Where:

RPS = Reserved contract purchases from and sales to OTHERS.

DSO = Demand side option equivalent capacity.

Cha = Total conventional hydro capacity less the unavailable portion of conventional hydro capacity.

Cna = Total nuclear capacity less the unavailable portion of nuclear capacity.

Coa = Total available pumped storage hydro, coal, combustion turbine, combined cycle, oil and gas steam, and purchased resource capacity required to meet the remaining portion of the OPERATING COMPANY's load responsibility, calculated as: L - RPS - DSO - Cha - Cna.

The unavailable portion of the total capacity is determined from the following formula:

LCR = Chu + Cnu + (Coa/(1 - (Cou/Cot)) - Coa)

Where:

Chu = Unavailable portion of conventional hydro capacity.

Cnu = Unavailable portion of nuclear capacity.

Cou = Total unavailable pumped storage hydro, coal, combustion turbine, combined cycle, oil and gas steam, and purchased resource capacity.

Cot = Total pumped storage hydro, coal, combustion turbine, combined cycle, oil and gas steam, and purchased resource capacity.

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Section 4.2 – Determination of Capacity Available to Each OPERATING COMPANY (C): The capacity available to each OPERATING COMPANY is determined monthly as the sum of available owned, leased, purchased or otherwise available generating units, reserved contract purchases from and sales to OTHERS, and seasonal or other power exchanges, all as established by the Operating Committee as part of the coordinated planning process. The capacity available is determined from the following formula:

C	=	Cc + Cn + Cog + Ccc + Cp + Cct + Ch + Cpsh + DSO + RPS + PRC

Where:

Cc	=	Coal capacity.
Cn	=	Nuclear capacity.
Cog	=	Oil and gas steam capacity.
Ccc	=	Combined cycle capacity
Cp	=	Peak Load capacity.
Cct	=	Combustion turbine capacity.
Ch	=	Conventional hydro capacity.
Cpsh	=	Pumped storage hydro capacity.
DSO	=	Demand side option equivalent capacity.
RPS	=	Reserved contract purchases from and sales to OTHERS.
PRC	=	Purchased resource capacity.

The components of the above formula shall be computed as detailed below. The capability demonstrated in accordance with such procedures shall be used in establishing the following year's capacity values. Where seasonal references are made, the seasons shall be defined as

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follows: Summer (June through September); Fall (October through November); Winter (December through February); and Spring (March through May).

Section 4.2.1 – Certified Rating: The production officer at each OPERATING COMPANY will certify the full load capability of each coal electric generating unit (excluding units from which Unit Power Sales and other similar bulk power sales are made), oil and gas steam electric generating unit, combined cycle unit, and combustion turbine unit. Southern Nuclear Operating Company will certify the capability of each nuclear steam electric generating unit. These certified ratings ("Full Load" ratings) shall represent the full load capability expected to be available continuously on a daily basis, under normal operating conditions, with all units at a given plant operating concurrently. Where appropriate, certified ratings shall be adjusted to reflect cogeneration and seasonal impacts. The production officer at each OPERATING COMPANY will also certify the peak load capability of generating units demonstrating such capability ("Peak Load" capability). The Peak Load capability shall represent the additional amount of generation obtained for a limited period of time by operating all units at a given plant concurrently and under conditions such as, but not limited to, overpressure, valves wide open and top feedwater heaters out of service. These unit ratings will be included in the informational filing submitted in accordance with ARTICLE VI of the IIC.

Section 4.2.2 – Coal (Cc)and Nuclear (Cn) Capacity: The Full Load rating of each coal and nuclear steam electric generating unit shall be based on the unit's capability during hours when such unit demonstrates full output during the months of June through August, adjusted for any temporary identifiable deratings.

Section 4.2.3 – Oil and Gas Steam Capacity (Cog): The Full Load rating of each oil and gas steam electric generating unit shall be based on the unit's demonstrated capability during

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hours when such unit demonstrates full output during the months of June through August, adjusted for any temporary identifiable deratings.

Section 4.2.4 – Combined Cycle Capacity (Ccc): The Full Load rating of combined cycle generating units shall be based on the unit's demonstrated capability during hours when such unit demonstrates full output during the months of June through August, adjusted for any temporary identifiable deratings. During the other months, an adjustment will be made to the Full Load rating to reflect the unit's capability at expected ambient temperatures for such non-summer period.

Section 4.2.5 – Combustion Turbine Capacity (Cct): The Full Load rating of combustion turbine units is based on the demonstrated output of such unit and the manufacturer's base design curve rating. Combustion turbine units shall demonstrate daily sustained capability during the months of June through August, adjusted for any temporary identifiable deratings. During the fall, winter and spring, adjustments will be made to the Full Load rating to reflect the unit's capability at expected seasonal ambient temperatures.

Section 4.2.6 – Peak Load Capacity (Cp): The Peak Load capacity of demonstrating generating units shall be the additional amount of generation obtained by operating all units at a given plant concurrently and under conditions such as, but not limited to, overpressure, valves wide open and top feedwater heaters out of service. The Peak Load capacity shall be based on such unit's demonstrated capability during hours when the unit demonstrates peak load capability during the months of June through August, adjusted for temporary identifiable deratings.

Section 4.2.7 – Conventional (Ch) and Pumped Storage (Cpsh) Hydro Capacity: For purposes of the IIC, hydro capability is the average simulated generation during eight (8)

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consecutive hours occurring on five (5) consecutive weekdays using the average water inflows from historical data. The simulation process utilizes maximum (full) gate setting and best (most efficient) gate setting to determine the capability of the hydro facilities. The capability for the months June-August is the summer maximum gate simulated rating. For the months December-May, the capability is the winter maximum gate simulated rating. The capability of the months September-November is the summer best gate simulated rating. To the extent that an OPERATING COMPANY can demonstrate that a hydro facility can actually achieve the maximum gate rating during the fall months, the capability of such hydro facility will be the maximum gate rating.

Section 4.2.8 – Active Demand Side Options – Equivalent Capacity (DSO): The equivalent capacity of each active demand side option for each month of the calendar year is determined from the following formula:

DSO = [(Cv x ICE) / (1 -(%TL/100))] x A

Where:

DSO = Demand side option equivalent capacity.

Cv = Contracted value.

ICE = Incremental capacity equivalent factor.

%TL = Six (6) percent incremental transmission losses.

A = Availability Factor.

The Incremental Capacity Equivalent Factor is a measure of the effect of a demand side option on generating system reliability. The Availability Factor is a measure of the probability of an active demand side option being available at the time it is needed.

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Section 4.2.9 – Reserved Contract Purchases and Sales (RPS): Reserved contract purchases and sales for any month include all contracted capacity purchases from and sales to OTHERS for which there are underlying reserves.

Section 4.2.10 – Purchased Resource Capacity (PRC): Purchased resource capacity includes all purchased capacity for which an underlying generating resource is identified and may represent any type of capacity (e.g., combined cycle).

Section 4.3 – Determination of Peak Hour Load Responsibility of Each OPERATING COMPANY (L): The monthly peak hour load responsibility of each OPERATING COMPANY is determined by the following formula:

$$L = L' \times La/100$$

Where:

L' = Monthly ten (10) highest hour average load of the integrated electric system.

La = Monthly average percent contribution of each OPERATING COMPANY's ten (10) highest hour average loads to the sum of those loads for all OPERATING COMPANIES for the most recent three-year period.

Section 4.4 – Recognition of Resource Additions or Deletions: For additions or deletions of capacity resources for the coming year, an adjustment will be made in the capability resources of the appropriate OPERATING COMPANY based upon the actual date of the addition or deletion (e.g., commercial operation, retirement, purchase, or sale); provided, however, that the adjustment will not be made in a month earlier than that originally established by the Operating Committee pursuant to the coordinated planning process. If the actual date is on or before the 15th day of the month, the capacity adjustment begins in that month. If the actual date is beyond the 15th day of the month, the capacity adjustment begins in the following month.

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Section 4.5 – Capacity Outside of the Coordinated Planning Process: If an OPERATING COMPANY has capacity that was not established by the Operating Committee as part of the coordinated planning process, such capacity will not be included as capacity available to the OPERATING COMPANY (pursuant to Section 4.2 of this Manual) for reserve sharing purposes ("unrecognized capacity"). Notwithstanding the foregoing, if an OPERATING COMPANY's monthly capacity/load ratio, as determined by comparing its available capacity (pursuant to Section 4.2 of this Manual) with its load responsibility (pursuant to Section 4.3 of this Manual), is less than the comparable ratio for the aggregate system (excluding the load responsibility and available capacity of the subject OPERATING COMPANY), then unrecognized capacity (up to an amount that will make these ratios comparable) will be designated as capacity available to that OPERATING COMPANY for that month.

ARTICLE V

RATE FOR MONTHLY RESERVE SHARING CAPACITY FOR EACH OPERATING COMPANY

Section 5.1 – Provision for Monthly Capacity Rate for Reserve Sharing: This article of the Manual establishes the formula rate for deriving the monthly reserve sharing capacity charge for each OPERATING COMPANY based on its most recently installed peaking facilities (or equivalent purchased resources) available for year-round operation or scheduling. OPERATING COMPANIES that have not installed or purchased such facilities or resources within the last five (5) years will utilize the weighted average rate of all the OPERATING COMPANIES that have installed or purchased such facilities or resources. In the event none of the OPERATING COMPANIES have installed or purchased such facilities or resources within the last five (5) years, the rate of the last facility or resource installed or purchased by any of them will be

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utilized for all OPERATING COMPANIES. The monthly reserve sharing capacity charges are utilized in the determination of payments to the Pool by the OPERATING COMPANIES purchasing capacity during the month and receipts from the Pool by the OPERATING COMPANIES selling capacity during the month. Each OPERATING COMPANY that sells reserve sharing capacity to the Pool will receive a payment based on the product of the amount of net capacity sales (CS) times that OPERATING COMPANY's monthly capacity rate. Each deficit OPERATING COMPANY will make payments to the Pool based on the product of the amount of net reserve sharing capacity purchased (CP) times the weighted average cost of such capacity sold to the Pool during the month. The monthly reserve sharing capacity rate of each OPERATING COMPANY for each month of the Contract Year is shown on Informational Schedule No. 3. Such rates will be revised in accordance with this Manual and the IIC in subsequent contract years.

Section 5.2 – Derivation of Monthly Capacity Costs of Each OPERATING COMPANY: The derivation of the monthly capacity costs of each OPERATING COMPANY, as used for purposes of the reserve sharing capacity rate, is based on one of the following: (i) the capacity cost of the most recently added peaking facility; (ii) the capacity cost of the most recent equivalent purchased resource; or (iii) the weighted system average of the capacity costs of the most recently added peaking facilities or equivalent purchased resources.

The monthly reserve sharing capacity rate of each OPERATING COMPANY for an installed peaking facility under subpart (i) will be determined by the following formula:

$$R1 = (I \times LFCC/100/C1) \times MCWF$$

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Where:

R1	=	Monthly charges for peaking facility ($/kW-Month).
I	=	Gross investment in peaking facility ($).
LFCC	=	16.3%, levelized fixed capacity charge.
C1	=	Peaking facility's rated production capability (kW), as determined by Section 4.2 of this Manual.
MCWF	=	Monthly Capacity Worth Factor for the applicable month.

The AGENT may periodically re-evaluate the monthly capacity worth factors based upon evaluations of system reliability. The governing MCWFs will be included in the Informational Schedules submitted in accordance with ARTICLE VI of the IIC.

For purposes of subpart (ii), the monthly reserve sharing capacity rate of each OPERATING COMPANY for an equivalent purchased resource will be the annual capacity rate ($/kW-Year) paid for such resource, multiplied by the applicable MCWF.

For purposes of subpart (iii), the monthly reserve sharing capacity rate will be the weighted system average of the costs of the most recently added peaking facilities (as determined for purposes of subpart (i)) or equivalent purchased resources (as determined for purposes of subpart (ii)), multiplied by the applicable MCWF.

Section 5.3 – Monthly Reserve Sharing Capacity Rate To Be Adjusted For Production Resource Change: If a peaking facility or an equivalent purchased resource of an OPERATING COMPANY is placed in commercial operation or available for scheduling by the 15th day of the month established by the Operating Committee as part of the coordinated planning process, the

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budgeted investment cost or annual capacity rate will be used in the determination of the monthly reserve sharing capacity rate for such OPERATING COMPANY for that and subsequent months of the calendar year. If the facility or resource is not placed in commercial operation or available for scheduling by the 15th day of such month, the cost basis established under Section 5.2, as used to derive the monthly reserve sharing capacity rate for the previous month, will remain in effect until the month in which the facility or resource is in commercial operation or available for scheduling on or before the 15th day.

ARTICLE VI

RATE FOR TIE-LINE LOAD CONTROL AND FREQUENCY REGULATION BY HYDRO FACILITIES

Section 6.1 – Provision for Hydro Regulation Energy Losses: Because of energy losses from hydro regulation, the OPERATING COMPANIES supplying this service are deprived of hydro energy. To distribute equitably this loss of energy among the OPERATING COMPANIES in accordance with size of loads regulated and to compensate the OPERATING COMPANIES for regulating services rendered, adjustments in billing determinations are necessary. Hydro energy losses actually incurred by regulating OPERATING COMPANIES during each day are replaced by the Pool at zero cost, and the AGENT allocates such energy losses to all OPERATING COMPANIES in accordance with Peak-Period Load Ratios. Energy lost during high-flow periods is replaced during the period in which such losses occur, and energy lost from poorer efficiencies during normal and low-flow periods is replaced during the 14-hour peak period since hydro energy so lost could have been retained in storage and generated during this period.

Section 6.2 – Provision for Increases in Cost Due to Hydro Regulation: Payments are made to hydro regulating OPERATING COMPANIES for each hour of such regulation for the increase

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in operating and maintenance expenditures for governor mechanisms and water turbine parts, and these expenses are allocated to all OPERATING COMPANIES in accordance with Peak-Period Load Ratios. Such payments are calculated using actual expenses incurred through the last calendar year available, adjusted to current-year dollars, for the cost of labor, engineering and supervision, and materials and supplies in the following FERC Accounts: 544-10, Generator and Exciters; 544-20, Hydraulic Turbines and Settings; 544-40, Governors and Control Apparatus; and 544-50, Powerhouse Remote Control Equipment. The basis for hourly payments is the difference in the average hourly costs for regulating plants and non-regulating plants, expressed in the following formula:

Hourly Charge	=	[MCW - (MCWO/HWO) x MCWH]/HOR
Where:		
MCW	=	Summation of costs for regulating plants.
MCWO	=	Summation of costs for non-regulating plants.
HWO	=	Summation of hours for non-regulating plants.
MCWH	=	Summation of hours for regulating plants.
HOR	=	Summation of hours in the regulating mode for regulating plants.

The regulating OPERATING COMPANIES shall supply the AGENT an hourly statement of energy losses incurred in providing hydro regulating services. Such statement should include sufficient detail to permit review and verification by the AGENT.

Section 6.3 – Regulation by Pumped Storage Hydro Projects: It is understood that pumped storage hydro projects owned by the OPERATING COMPANIES may also be used for regulation of the integrated electric system. In such event, the hourly charge for such regulation will be the same charge derived under the formula contained in Section 6.2 hereof.

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Section 6.4 – Provision for Increases in Cost Due to Hydro Scheduling: Because the use of hydro resources for tie-line load control and frequency regulation does not allow the hydro energy to be scheduled in the most cost effective manner, less economic gains are achieved than would have been if the hydro energy had been used to displace only the highest cost other energy sources. The difference in actual displacement costs represents the value of the lost economic opportunity by the owning OPERATING COMPANY by such use of hydro energy, or the costs of providing higher cost energy. The AGENT shall allocate such costs to all the OPERATING COMPANIES in accordance with Peak-Period Load Ratios.

[END OF MANUAL]

Southern Company

Determination of Annual Capacity Rate

January 1, 2024 - December 31, 2024

Reference: Manual, Article V

	Alabama	Georgia	Mississippi	Southern Power
Rate Basis:	Purchased Resource	Purchased Resource	Purchased Resource	Purchased Resource
1. Net Production Capacity (kW)	17,104	21,462	3,446	7,988
2. Gross Investment in Peaking Facilities (I)				
3. Levelized Fixed Capacity Charge (LFCC)				
4. Annual Charge ($ per kW year)	$ 73.200000 (a)	$ 73.200000 (b)	$ 73.200000 (d)	$ 73.200000 (e)

Notes:
(a) Cost of Peaking Resources Purchased by Alabama Power Company
(b) Cost of Peaking Resources Purchased by Georgia Power Company
(d) Cost of Peaking Resources Purchased by Mississippi Power Company
(e) Cost of Peaking Resources Purchased by Southern Power Company

MONTHLY CAPACITY CHARGES
FOR RESERVE SHARING PURPOSES
($/KW-MO)

	Monthly Capacity Worth Factors	Alabama	Georgia	Mississippi	Southern Power
January - December 2024		***73.200000***	***73.200000***	***73.200000***	***73.200000***
January	0.50	36.600000	36.600000	36.600000	36.600000
February	0.10	7.320000	7.320000	7.320000	7.320000
March	0.01	0.732000	0.732000	0.732000	0.732000
April	0.01	0.732000	0.732000	0.732000	0.732000
May	0.01	0.732000	0.732000	0.732000	0.732000
June	0.04	2.928000	2.928000	2.928000	2.928000
July	0.10	7.320000	7.320000	7.320000	7.320000
August	0.10	7.320000	7.320000	7.320000	7.320000
September	0.01	0.732000	0.732000	0.732000	0.732000
October	0.01	0.732000	0.732000	0.732000	0.732000
November	0.01	0.732000	0.732000	0.732000	0.732000
December	0.10	7.320000	7.320000	7.320000	7.320000

MONTHLY LOAD CAPACITY COMPARISON

MW PURCHASE OR (SALE)

	ALABAMA	GEORGIA	MISSISSIPPI	SOUTHERN POWER
January	-	-	-	-
February	(147.097)	(0.189)	147.285	-
March	(191.939)	-	191.939	-
April	-	(344.113)	656.885	(312.772)
May	-	(267.072)	467.201	(200.128)
June	(36.803)	(36.429)	81.308	(8.077)
July	-	-	-	-
August	-	-	-	-
September	-	(98.067)	135.351	(37.284)
October	-	-	172.337	(172.337)
November	-	-	-	-
December	-	-	-	-
Total 2024	**(375.838)**	**(745.870)**	**1,852.306**	**(730.598)**

DOLLAR PAYMENTS OR (RECEIPTS)

	ALABAMA	GEORGIA	MISSISSIPPI	SOUTHERN POWER
January	$ -	$ -	$ -	$ -
February	$ (1,076,747)	$ (1,381)	$ 1,078,128	$ -
March	$ (140,499)	$ -	$ 140,499	$ -
April	$ -	$ (251,891)	$ 480,840	$ (228,949)
May	$ -	$ (195,497)	$ 341,991	$ (146,494)
June	$ (107,758)	$ (106,663)	$ 238,069	$ (23,648)
July	$ -	$ -	$ -	$ -
August	$ -	$ -	$ -	$ -
September	$ -	$ (71,785)	$ 99,077	$ (27,292)
October	$ -	$ -	$ 126,151	$ (126,151)
November	$ -	$ -	$ -	$ -
December	$ -	$ -	$ -	$ -
Total 2024	**$ (1,325,004)**	**$ (627,217)**	**$ 2,504,755**	**$ (552,534)**

( ) Indicates Sales to Pool