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September 23, 2026

**VIA ELECTRONIC DELIVERY**

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

**Re: Direct Testimony of John D. Wilson on Behalf of Georgia Interfaith Power & Light, Park Avenue Baptist Church, Temple Sinai, and Unitarian Universalist Church of Savannah; Docket No. 57171**

Dear Ms. Tanner:

Please find enclosed an electronic version of the following Direct Testimony of John D. Wilson to be filed in Docket No. 57171 regarding Georgia Power's Real Time Pricing ("RTP") Revenue Credit and Allocation Methodology on behalf of Georgia Interfaith Power & Light, Park Avenue Baptist Church, Temple Sinai, and Unitarian Universalist Church of Savannah.

Respectfully submitted,

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**STATE OF GEORGIA**

**BEFORE THE**

**PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In Re:** | **)** | |
| | **)** | |
| **Real Time Pricing Revenue Credit and** | **)** | **Docket No. 57171** |
| **Allocation Methodology** | **)** | |

# DIRECT TESTIMONY OF JOHN D. WILSON
# ON BEHALF OF
# GEORGIA INTERFAITH POWER & LIGHT, PARK AVENUE BAPTIST CHURCH, TEMPLE SINAI, AND UNITARIAN UNIVERSALIST CHURCH OF SAVANNAH

September 23, 2026

**PUBLIC DISCLOSURE VERSION**

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

A: My name is John D. Wilson. I am the Vice President of Grid Strategies LLC, which is headquartered in Bethesda, MD, and my office is in Lexington, KY.

**Q: PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.**

A: I received a BA degree from Rice University in 1990, with majors in physics and history, and an MPP degree from the Harvard Kennedy School of Government with an emphasis in energy and environmental policy, and economic and analytic methods. I have been employed by Grid Strategies since 2023, and previously, I performed similar duties as an employee of Resource Insight.

Prior to entering consulting in 2019, I was deputy director of regulatory policy at the Southern Alliance for Clean Energy (SACE) for more than twelve years, where I was the senior staff member responsible for SACE's utility regulatory research and advocacy, as well as energy resource analysis. I engaged with southeastern utilities through regulatory proceedings, formal workgroups, informal consultations, and research-driven advocacy.

My work has considered and entailed, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, energy conservation program design, prudency review, ratemaking and cost recovery for utility efficiency programs, allocation of costs of service between rate classes and jurisdictions, design of retail rates, and performance-based ratemaking for electric utilities.

My current clients include consumer advocates, a state regulatory commission, renewable energy trade associations, and clean energy advocacy organizations. A copy of my

professional resume, which includes my employment history, education, and history of commission and similar hearings, is attached as Exhibit JW-1 to this testimony.

**Q: HAVE YOU TESTIFIED PREVIOUSLY IN UTILITY PROCEEDINGS?**

A: Yes. I have testified more than eighty times before utility regulators in twelve U.S. states and Nova Scotia and appeared numerous additional times before various regulatory and legislative bodies.

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

A: Yes. I have testified seven times before this Commission, as listed in the attached resume.

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

A: Georgia Interfaith Power and Light (GIPL), and its member congregations Park Avenue Baptist Church, Temple Sinai, and Unitarian Universalist Church of Savannah.

## FINDINGS AND RECOMMENDATIONS

**Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS CASE.**

A: I have two sets of recommendations for the Commission. First, I find that Georgia Power has set its RTP price too low during peak hours because the reliability cost component was set inconsistently with the peaker method. Accordingly, I recommend that the Commission direct Georgia Power to:

1. File its method for calculating the transmission and reliability cost component prices in the rate case docket, with full details on the source(s) of market value data and how the prices are to be calculated. If the Commission has concerns that either

calculation method is inconsistent with prior orders or otherwise potentially adverse to the interests of other customers, it should direct further proceedings as appropriate.

2. File its annual update of RTP transmission and reliability cost component prices as a compliance filing in the rate case docket with evidence demonstrating how it has followed the Commission-approved method.
3. If Georgia Power seeks to make changes to the method, file the proposed revised method at least 60 days prior to its annual update so that the Commission has an opportunity to review that change and determine if further proceedings are necessary prior to the update becoming effective.

Furthermore, I also suggest that the Commission should direct Georgia Power to engage with its Staff and intervenors to reconsider the appropriateness of the design of its transmission and reliability cost components.

Second, I find that several categories of costs recovered from FCR customers are not included in the RTP fuel credit. The RTP fuel credit – on a $/MWh basis – is therefore an underestimate of the fuel costs that should be allocated to the incremental load priced at RTP. Accordingly, I make several recommendations for changes to the RTP fuel credit, including that the Commission should:

4. Adopt Georgia Power's recommendation to "exclude both the costs and the output from non-dispatchable PPAs in the RTP fuel credit calculation."

5. Adopt, with modifications, Georgia Power's recommendation to recover the costs of new firm transportation (FT) cost from large load customers, excluding those costs from the FCR rate.
6. Revise the RTP fuel credit calculation to include direct contributions to FT cost, assuming fixed fuel delivery costs are not included in the marginal value of generation capacity. If that is not the case, then I provide two alternate recommendations whereby the Commission should either allocate FT costs to RTP customers in the fuel docket or move FT costs to base rates.
7. Reject Georgia Power's proposal for a winter 1CP allocation of new FT cost, instead using the same allocation factor as transmission costs until the issue is fully examined in the next rate case. To the extent that the Commission seeks to rely on Georgia Power's large load cost model, the Commission should also direct Georgia Power to make a working copy available to intervenors on a basis that addresses commercial sensitivity concerns yet allows for full stakeholder participation in Commission decisions based wholly or in part on that model.
8. Revise the RTP fuel revenue credit to include coal-related costs and corporate overhead and labor.

Furthermore, I suggest that, in the next rate case, the Commission consider updating the RTP rate design to also include corporate overhead and labor as well as FT, coal-related, and other fixed fuel delivery costs if it is determined that the reliability cost component of the RTP rate does not include these costs. This could be simply accomplished by updating

the recovery factor. I also draw to the Commission's attention the effect of including large load growth in the hedging cap approved as part of the FCR-27 settlement.

## BACKGROUND

**Q: WHY IS THE COMMISSION REVIEWING THE RTP REVENUE ALLOCATION METHODOLOGY?**

A: In the last few years, the Commission has approved the procurement of thousands of megawatts of new generation resources to accommodate large load customers. Given the magnitude of the billpayer investments forecasted by Georgia Power, the Commission has treated these large loads in a distinct manner, holding them to a higher standard when it comes to cost shifting. The FCR-27 proceeding was the first fuel proceeding since the data center boom began and parties raised concerns that the current RTP methodology, which has been applied to data center customers, resulted in higher fuel costs for other customers, in apparent contravention of Georgia Power's statements that data centers would not be subsidized by existing customers.

**Q: IS THE STANDARD FOR LARGE LOAD CUSTOMERS LIKE DATA CENTERS DIFFERENT THAN FOR OTHER RTP CUSTOMERS?**

A: Yes. The Commission has ordered Georgia Power to "protect existing customers from bearing any of the costs of adding these large customers."[1] The Commission has further ordered Georgia Power to "file its next base rate case in a manner that will ensure the incremental revenue from large load customers has downward pressure … to the typical

[1] Order on Georgia Power Company's Revision to Rules and Regulations Tariff Compliance Filing, Dkt. 44280 (April 17, 2025).

residential customer … for the years 2029, 2030, and 2031."[2] As described on the homepage of the Commission's website, "These rules ensure NO residents or small businesses will see increases on their power bills due to data centers."[3]

## PURPOSE OF REAL-TIME PRICING

**Q: WHAT IS THE BASIS OF GEORGIA POWER'S REAL-TIME RATE DESIGN?**

A: Georgia Power's real-time rate design is intended to recover the full marginal cost of meeting electric demand. The rate design is founded on the peaker method, which "reproduces the true optimal-mix marginal cost."[4] Georgia Power further states that, "At the least-cost mix, the peaker-based total exactly equals the true cost built up tier-by-tier – peaking, intermediate, and base."[5]

Practically speaking, the RTP rate gives customers an option to take on price risk in exchange for potential cost savings.

The total RTP rate design, which I will summarize later in my testimony, is intended to contribute both fuel and base revenues. The RTP fuel credit represents the revenues to cover fuel costs and the remainder represents a contribution to base revenues, also referred to as "capital substitution."

For large load customers on TOU-SC MAC, the Monthly Access Charge (MAC) also recovers base revenues and all energy is billed at the hourly RTP-DA price. For other RTP

[2] Order Adopting Stipulation and Granting Certification of Capacity from the 2029-2031 All-Source RFP and Supplemental Resources for 2028-2031 Capacity, at 12, Dkts. 56298 & 56310 (Dec. 30, 2025)
[3] Georgia PSC, "Information on Data Centers," available at psc.ga.gov (last accessed Sept. 23, 2026) (emphasis in original).
[4] Georgia Power's Response to STF-JKA-3-1 Attachment at 17, Dkt. 57171 (Sept. 3, 2026).
[5] *Id.*

customers, the Customer Baseline Load (CBL) portion of their bill collects both variable and fixed costs. The combination of "capital substitution" and base revenues recovered through the MAC or CBL portions of a customer's bill are intended to cover fixed costs associated with providing the customer service.

**Q: DOES CAPITAL SUBSTITUTION REPRESENT DOWNWARD PRESSURE ON RATES?**

A: No. Capital substitution is a core component of the peaker method and represents the contribution from lambda to the cost of more efficient generation. As an example, if a utility built all peakers, then system lambda would be approximately equal to average fuel costs, and there would be no surplus to provide capital substitution – but capital substitution would be unnecessary because the marginal cost of generation, based on the peaker cost, would also be covered. This is because the marginal cost of generation is set to cover the full cost of a peaker unit. Thus, if a customer's energy use is fully priced using RTP, then in theory the RTP rate covers the full cost of that peaker unit.

However, Georgia Power does not fully rely on peakers, at some periods the system lambda recovers more revenues than are credited to cover fuel costs. This surplus is needed to cover the higher cost of generation that operates more frequently than peakers (e.g., intermediate units). This is a necessary cost of service, and from an economics perspective does not provide further surplus to represent downward pressure on rates.

**Q: IF FUEL COSTS INCREASE AND RTP REVENUE IS SHOWN TO COVER THAT INCREASE, DOES THAT REPRESENT DOWNWARD PRESSURE ON RATES?**

A: No. If average fuel costs increase, but RTP revenue increases sufficiently to cover that increase in costs, then FCR customer costs are unaffected. This represents an avoidance of harm, not downward pressure on rates.

**Q: DO YOU AGREE THAT THE PEAKER METHOD IS SOUND?**

A: Yes, provided that the underlying assumptions hold. There are two basic ways that underlying assumptions may be violated. First, if Georgia Power's actual costs are greater than predicted by application of the peaker method, cost recovery through the RTP rate would be less than cost recovery using an embedded cost rate. Second, even if actual costs are commensurate with the peaker method, if some cost categories are not actually considered in the components of the RTP rate, then the RTP rate may under-recover costs.

**Q: ARE THERE ANY CONDITIONS ON GEORGIA POWER'S SYSTEM THAT MAY CAUSE ACTUAL COSTS TO EXCEED THOSE PREDICTED BY THE PEAKER METHOD?**

A: Yes, if for policy reasons or for expediency, Georgia Power does not "optimally serve added load,"[6] such as by generating power from uneconomic plants, then a portion of those generation costs is by definition in excess of those predicted by the peaker method.

**Q: WHAT ARE EXAMPLES OF POLICY REASONS A PLANT MAY BE DISPATCHED OR KEPT IN SERVICE ON AN UNECONOMIC BASIS?**

A: Certain coal plants may be being kept in service or dispatched on a must-run basis due to federal policy direction or unexpected growth in load. The U.S. Department of Energy has directed certain coal plants to be kept in service under a FPA Section 202(c), although it is

[6] *Id.* at. 21.

my understanding that federal courts have found those actions unlawful. Where fixed O&M costs are incurred where an alternative resource could have been more economic, the peaker method is violated.

Similarly, if due to unexpected growth in load, the choice of potential technologies is restricted due to resource development timelines, this also violates the peaker method. Even if it is reasonable to build a particular form of generation because it is the only available unit in the timeframe selected, it may not be an optimal unit under the peaker method's assumption of a well-planned system.

One test to determine if generation resource costs are uneconomic is to verify that the resource costs were included in the optimal plan resulting from an appropriate resource mix study. While this may not be definitive evidence that a resource is economic, it is unlikely that an economic resource would be excluded from selection in such a mix study. Georgia Power indicates that the mix study is the "traditional way" to estimate marginal cost, and that the peaker method is a simpler alternative to this method.[7]

**Q: HAVE THESE ISSUES BEEN DOCUMENTED IN ECONOMIC RESEARCH?**

A: Yes. One example is a 2011 paper by Ehrenmann and Smeers which discussed how risk aversion creates a shift towards less capital-intensive technologies (and thus more fuel-intensive technologies) and may also increase a shortage in capacity.[8] Maintaining inefficient generation and limiting generation selection to technologies that can be

[7] *Id.* at 11-17.

[8] Note that while this paper focuses on restructured markets, its use of an equilibrium model "substitutes optimization to account for competition," which suggests the findings also apply to vertically-integrated utilities that optimize using capacity expansion models. Andreas Ehrenmann and Yves Smeers, Generation Capacity Expansion in a Risky Environment: A Stochastic Equilibrium Analysis, *Operations Research*, November-December 2011, Vol. 59, No. 6, pp. 1332-1346, available at https://www.jstor.org/stable/41316039.

developed quickly are forms of risk aversion. If a utility's generation portfolio is biased due to risk-aversion, this research suggests that it may be expressed more strongly as upward pressure on fuel costs than generation base rates. This emphasizes the import of this proceeding making large load costs more visible and appropriately accounted for, because this upward pressure is caused by large load customers and concealed in FCR rate increases.

**Q: HAVE RECENT PROCUREMENTS REFLECTED THE PEAKER METHOD'S ASSUMPTION OF A WELL-PLANNED SYSTEM?**

A: Arguably not. It is my understanding that recent procurements of generation resources by Georgia Power were selected under significant time pressure and in some cases without the benefit of a competitive bidding process. It is also mu understanding that for the All-Source RFP resources certified last year, every single proposal that complied with the conditions of the RFP was chosen—in other words, no resources were excluded for being too expensive.

**Q: ARE THERE ANY COST CATEGORIES THAT GEORGIA POWER DOES NOT CONSIDER IN THE COMPONENTS OF THE RTP RATE?**

A: Yes. Even to the extent that Georgia Power optimally serves added load, there are several costs of service that are not considered in the components of the RTP rate – except to the extent that they are included in the recovery factor.

## REAL-TIME PRICING METHOD

**Q: PLEASE SUMMARIZE THE PEAKER METHOD UNDERLYING THE RTP RATE DESIGN.**

A: Georgia Power summarizes the peaker method as follows:

> The total marginal cost to serve incremental load can be reliably and accurately calculated using the cost of peaking capacity, priced against demand during peak periods, and the marginal production cost of the system in all hours. This analytical approach is known as the peaker methodology, which represents the total capacity and energy cost to serve demand from an optimal resource mix and provides a proper basis for the Company's RTP rates.[9]

The marginal cost is set to encourage "usage when the marginal unit cost is lower and discouraging usage when that cost increases."[10] It includes five components:

- **Lambda:** marginal cost of resource dispatch
- **Losses (RTP-DA Only):** physical electric losses
- **Recovery factor:** provides Georgia Power profit, compensation for the risk that advance quotes of RTP prices understate actual prices,[11] and other costs such as distribution costs[12]
- **Transmission cost:** marginal capital cost of transmission
- **Reliability capacity cost:** marginal value of generation capacity

**Q: PLEASE PROVIDE AN EXAMPLE ILLUSTRATING THE RELATIVE SIZE OF EACH OF COMPONENT OF THE RTP PRICE.**

[9] Direct Testimony of Dr. Ross Beppler, Lee Evans, and Brandon Looney on behalf of Georgia Power Company, at 7:4-10, Dkt. 57171 (Aug. 14, 2026) ["GPC Direct Testimony"].
[10] GPC Direct Testimony at 8:3-4.
[11] Order, at 6, Dkt. 11708-U In re: Petition for Rule Nisi to Examine Georgia Power Company's Real Time Pricing Structure (May 12, 2000).
[12] Transcript of Hearing on Georgia Power's Direct Testimony in Docket 57171, at 113:2-6 (Sept. 1, 2026) ["Hearing Transcript"].

A: Table 1 shows RTP revenue by rate component for 2023, with the revenue from lambda further split into the RTP fuel credit and the revenue contribution for generation variable O&M and capital substitution.

***Table 1: 2023 RTP Revenue by Rate Component***[13]

| | $ (millions) | Percent |
|---|---|---|
| **Lambda: RTP Fuel Credit** | [redacted] | [redacted] |
| **Lambda: O&M / Capital Substitution** | | |
| **Recovery Factor** | | |
| **Transmission Cost** | | |
| **Reliability Capacity Cost** | | |
| **Total Revenue** | | |

However, the total revenue based on this calculation differs from the $740.0 million total provided in another discovery response.[14]

**Q: HOW WELL DOES THIS ALIGN WITH GEORGIA POWER'S FORECAST OF 2023 REVENUE IN ITS 2022 RATE CASE?**

A: Based on the response to GIPL Hearing Request No. 1 and data from the 2022 rate case, the capital substitution from the lambda rate component for the test year ending July 31, 2023 was forecast to be $158.3 million, the transmission cost was forecast to be $33.6 million, and the reliability capacity cost was forecast to be $21.7 million.[15]

**Q: PLEASE EXPLAIN HOW GEORGIA POWER CALCULATES THE MARGINAL VALUE OF GENERATION CAPACITY.**

[13] Calculated from Georgia Power's Trade Secret Attachments to STF-JKA 3-5, JKA-3-8, and JKA-8-7 in Docket 56765.
[14] Georgia Power's Response to STF-JKA-4-6 Attachment, Dkt. 56765 (March 30, 2026).
[15] Direct Testimony of Lee Evans on behalf of Georgia Power Company, Exhibit LPE-2, Dkt. 44280 (June 24, 2022).

A: From 2020 to 2024, Georgia Power used the "[redacted]"[16]

However, Georgia Power deviated from this approach in 2023, 2024, and 2025:

- In 2023, Georgia Power disregarded the [redacted].[17]
- In 2024, Georgia Power again justified deviations from its prior approach [redacted].[18]
- In 2025, Georgia Power changed to a different data source for the capacity value, [redacted].[19] Again, Georgia Power used a [redacted]

[16] Georgia Power's Response to STF-JKA-10-11 Attachment A TRADE SECRET, Dkt. 56765 (July 14, 2026).
[17] *Id.*
[18] *Id.*
[19] Circumstantial evidence suggests that [redacted] *Id.* Attachments A and G TRADE SECRET.

[redacted]

[redacted].[20]

**Q: WHAT SPECIFIC COSTS OF NEW GENERATION CAPACITY ARE INCLUDED IN GEORGIA POWER'S MARKET VALUE ESTIMATES?**

A: This information was not provided by Georgia Power. For example, it is unclear whether these costs would include firm transportation delivery costs for natural gas or costs related to coal quality and delivery (e.g., rail cars) if the market value were determined by a gas or coal unit. Similarly, if the market value is based on a battery storage unit, consideration might (or might not) be given to charge cycle losses, degradation, and other costs that may be viewed as either fixed or variable. This is relevant because it remains unclear exactly what fixed costs are included in Georgia Power's marginal value data.

**Q: IS GEORGIA POWER'S RECENT METHOD FOR CALCULATING THE VALUE OF CAPACITY FOR THE RELIABILITY COMPONENT OF THE RTP RATE CONSISTENT WITH THE PEAKER METHOD?**

A: No. In 2023, 2024 and 2025 Georgia Power charged RTP customers a significantly lower price than its contemporaneous data for the marginal cost of capacity. Georgia Power's justification that capacity prices were driven by [redacted] was demonstrated, in hindsight, to be flawed. In Table 2, I compare the Trade Secret market-derived capacity value with the reliability cost used by Georgia Power to, in combination with a loss factor, determine the reliability price used for the reliability component of the RTP Rate.

[20] *Id.* Attachment A TRADE SECRET.

*Table 2: Value of Capacity vs RTP Reliability Cost Component, 2023-2025*[21]

| | Value of Capacity ($/kW-Yr) | Reliability Price ($/kW-Yr) | Reliability Cost ($/kW-Yr) |
|---|---|---|---|
| 2023 | [redacted] | [redacted] | [redacted] |
| 2024 | | | |
| 2025 | | | |
| Average | | | |
| Variation | | | |

Over these three years, the market value of capacity was much higher than the reliability cost included in RTP rates for each year. Furthermore, the market value showed much more stability than Georgia Power's "reliability cost."

Thus, while the RTP rate is intended to encourage "usage when the marginal unit cost is lower and discouraging usage when that cost increases,"[22] in fact Georgia Power set the RTP rate so low that it encouraged more usage than it should have.

**Q: COULD AN UNREASONABLY LOW RTP RATE ENCOURAGE EXCESS DEMAND?**

A: Yes. A well-informed customer with visibility into Georgia Power's historical RTP rates during 2023-2025 could form an unreasonable expectation that the RTP rates during peak hours appear to be lower than market conditions might suggest, and could then proceed to make both short-term operational decisions and long-term investment decisions based on these incorrect prices.

**Q: IS A [redacted] OF CAPITAL COSTS A MARGINAL COST CALCULATION?**

[21] *Id.*
[22] GPC Direct Testimony at 8:3-4.

A: No. A [redacted] cost is closer to [redacted]. Georgia Power's [redacted] method – which [redacted] – does appear to be a reasonable basis for market price data. A marginal capacity cost cannot be measured in a single hour as is done for lambda. But, as shown in Table 2 above, a [redacted] can persistently misrepresent the current market price for generation capacity.

**Q: WAS THE COMMISSION OR STAFF INFORMED AS TO THESE DECISIONS BY GEORGIA POWER?**

A: The evidence I have reviewed includes no suggestion that Georgia Power informed the Commission or Staff as to its pricing decisions, or considered any views other than its own in deciding how to set the reliability component of the RTP rate.

**Q: HOW COULD OTHER CUSTOMERS BE AFFECTED BY THIS PRICING STRATEGY?**

A: Setting the RTP price too low during peak hours can affect other customers through both effects on RTP customer demand and on revenue forecasts during rate cases.

**Q: HOW CAN SETTING THE RTP PRICE TOO LOW DURING PEAK HOURS IMPACT RTP CUSTOMER DEMAND?**

A: Setting the RTP price too low during peak hours sends an improper price signal to RTP customers, resulting in more energy use than would occur with an accurate RTP price signal. In theory, RTP customers pay for this increased energy use through the RTP fuel revenue credit, as discussed below. But as also discussed below, RTP customer energy use can affect either the amount or the cost allocation of certain "fixed" fuel-related costs that

are included in the FCR; thus, uneconomically high RTP customer energy use can drive up fuel costs for other customers.

**Q: HOW CAN SETTING THE RTP PRICE TOO LOW DURING PEAK HOURS AFFECT RTP CUSTOMER REVENUE FORECASTS DURING RATE CASES?**

A: In a rate case, test year costs are compared to test year revenues. If the RTP price is set too low during a year that is used as a test year during a rate case, then system revenues will be depressed. This will tend to drive up rates.

To some extent, this may be mitigated for non-RTP customer classes since the classes with RTP customers presumably would show a greater revenue deficiency. But as Georgia Power's testimony states, RTP rate design is intended to "ensure[] that the expected revenues more than cover the incremental costs to serve new load."[23] But if the RTP rates are set too low, as suggested in Table 2, then the actual revenues will not cover those incremental costs – and thus recovery of those costs will be shifted to other customer classes.

**Q: ARE CHANGES TO RTP RATE DESIGN WITHIN THE SCOPE OF THIS PROCEEDING?**

A: No. Nonetheless, I recommend that Georgia Power propose for Commission review and approval RTP pricing that utilizes [redacted] as quickly as possible.

**Q: WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?**

[23] GPC Direct Testimony at 10:5-6.

A: It appears that Georgia Power has exercised what can charitably be described as exceptionally broad discretion in determining the reliability price component of the RTP rate. These decisions have potentially already harmed other customers. Accordingly, the Commission should direct Georgia Power to take the following steps.

First, Georgia Power should be directed to file its method for calculating the transmission and reliability cost component prices in the rate case docket, with full details on the source(s) of market value data and how the prices are to be calculated. If the Commission has concerns that either calculation method is inconsistent with prior orders or otherwise potentially adverse to the interests of other customers, it should direct further proceedings as appropriate.

Second, the Commission should require Georgia Power to file its annual update of RTP transmission and reliability cost component prices as a compliance filing in the rate case docket with evidence demonstrating how it has followed the Commission-approved method. This would be similar to its annual avoided cost filing.

Third, if Georgia Power seeks to make changes to the method, it should be required to file its revised method at least 60 days prior to its annual update so that the Commission has an opportunity to review that change and determine if further proceedings are necessary prior to the update becoming effective.

**Q: DO YOU HAVE OTHER COMMENTS ON THE TRANSMISSION AND RELIABILITY COST COMPONENTS?**

A: Yes. I suggest that the Commission should direct Georgia Power to engage with its Staff and intervenors to reconsider the design of its transmission and reliability cost components.

While the basic design of those components is sound – allocating generation and transmission costs over multiple hours based on load and, in the case of transmission, temperature, since Georgia Power developed this method, there have been advances in other jurisdictions that could inform an improved RTP design.

In a case involving the design of a real-time pricing rate for Pacific Gas & Electric (PG&E), I represented small business interests in identifying flaws in its proposed rate design. PG&E accepted my critique, and engaged in a multi-party rate design study that resulted in an improved proposal, which was accepted by the California Public Utilities Commission.

Keeping it very simple, that design involved allocating capacity costs over many hours of the year, but using an "S-shaped" curve that set capacity prices relatively low when net demand was low, and then escalated sharply as demand began to reach high levels, only to mostly level off at the highest levels.

Replicating the same design in Georgia may or may not be a good match for the different circumstances, but some of the key lessons do apply. The RTP capacity price signal was explicitly designed to be closely aligned with grid stress as experienced on the PG&E system. This is very much the definition of a cost-based rate design.

## RTP FUEL CREDIT

**Q: WHAT IS THE RTP FUEL CREDIT?**

A: The RTP Fuel Credit is the process for recording a portion of revenues from incremental load priced at RTP as a credit in the FCR. In other words, FCR customers pay all fuel costs net of the RTP Fuel Credit. The RTP fuel credit is currently calculated as follows:

$$\text{RTP Fuel Credit} = \frac{\left(\begin{array}{c}\textbf{Georgia Power}\\ \textbf{“Bottom of Stack”}\\ \textbf{unit costs} (\$)\end{array} \pm \begin{array}{c}\textbf{Pool Purchases}\\ \textbf{and Sales} (\$)\end{array}\right)}{\left(\begin{array}{c}\textbf{All Georgia Power}\\ \textbf{Generation} (\text{MWh})\end{array} \pm \begin{array}{c}\textbf{Pool Purchases}\\ \textbf{and Sales} (\text{MWh})\end{array}\right)}$$

**Q: DO YOU SUPPORT THE CURRENT RTP FUEL CREDIT METHOD?**

A: No. Several categories of costs recovered from FCR customers are not included in either the Georgia Power unit costs or the pool purchases/sales cost. The credit – on a $/MWh basis – is therefore an underestimate of the fuel costs that should be allocated to the incremental load priced at RTP. This shifts costs to FCR customers.

While in this proceeding, Georgia Power has agreed to make some changes, it argues that the current method is fair, as any revenues that are not recorded as a credit in the FCR are recorded as base revenues, and serve to diminish the revenue requirement for other customers collected through base rates. While I agree with this concept, it neglects two critical factors: cost allocation in the FCR differs from cost allocation in base rates, and the FCR is subject to under- or over-recovery that is carried forward as a balance, which may affect either an FCR filing or a rate case.

Accordingly, the Commission should resolve this proceeding by appropriately identifying costs in the FCR that should be recovered from incremental load priced at RTP and allocating an appropriate portion of those costs to the RTP fuel credit.

**Q: WHAT COST CATEGORIES ARE RECOVERED FROM FCR CUSTOMERS BUT ARE NOT INCLUDED IN THE CURRENT RTP FUEL CREDIT?**

A: Georgia Power has provided the following list:

- Natural gas firm transportation
- Natural gas storage
- Natural gas hedging gains/losses
- Natural gas (gains)/losses on resales
- Coal quality penalties and premiums
- Coal rail car lease
- Rail car shortfall/liquidated damages costs
- Start-up costs for Purchase Power Agreements (PPAs)
- Energy costs associated with non-dispatchable PPAs (Solar, Wind, Biomass, and Qualifying Facilities)
- FCR over/under-balance carrying costs
- Income Qualified Discount (IQD) program costs
- Net Renewable Program (Revenues)/Expenses
- Corporate overhead and labor[24]

**Q: HOW DOES GEORGIA POWER PROPOSE TO HANDLE NON-DISPATCHABLE PPAs IN THE RTP FUEL CREDIT CALCULATION?**

A: While non-dispatchable PPA costs are currently excluded from the RTP fuel credit calculation, the generation output from those PPAs is included in the RTP fuel credit calculation. Georgia Power's direct testimony presented two options to address the concern that this results in an underestimate of the RTP fuel credit calculation. Georgia Power testified that they preferred the first option:

> … to exclude both the costs and the output from non-dispatchable PPAs in the RTP fuel credit calculation. This is consistent with an approach that the RTP fuel credit should be derived from marginal replacement fuel costs. Removing non-dispatchable PPA output (MWh) from the denominator of the RTP fuel credit calculation will increase the RTP fuel credit rate and thus the recording of all RTP revenues to the fuel clause.[25]

[24] Georgia Power's Response to STF-JKA-3-6 Attachment PUBLIC DISCLOSURE, Dkt. 57171 (Sept. 3, 2026).
[25] GPC Direct Testimony at 18:2-8; Hearing Transcript at 105:7-13.

**Q: DO YOU SUPPORT THIS PROPOSAL?**

A: Yes. This resolves this problem with the current RTP fuel credit calculation.

I would further note that as long as the output from non-dispatchable PPAs remains less than the load from FCR customers, then the net effect of this approach is to assign both the costs and the benefits of non-dispatchable resources to FCR customers. This is appropriate, as incremental RTP load should be assigned the cost of resources that may be dispatched in response to price-sensitive demand.

**Q: HOW DOES GEORGIA POWER PROPOSE TO HANDLE FIRM TRANSPORTATION (FT) IN THE RTP FUEL CREDIT CALCULATION?**

A: Georgia Power's proposal is:

> … that the costs of new FT attributable to large load customers be fully recovered from those customers and not borne by non-large load customers in the FCR clause … [and] proposes using a winter CP and basing the allocation on the share of organic versus large load demand growth.[26]

**Q: DO YOU SUPPORT THIS PROPOSAL?**

A: Yes, but with modifications. I agree with Georgia Power that removing the costs of new FT attributable to large load customers from the FCR clause addresses one problem with the current RTP fuel credit calculation. However, I do not agree that it is reasonable to excuse incremental RTP load from an explicit allocation of FT cost, nor do I agree with the proposed cost allocation factor for FT attributable to large load customers.

**Q: WHY IS IT UNREASONABLE TO EXCUSE INCREMENTAL RTP LOAD FROM AN EXPLICIT ALLOCATION OF FT COSTS?**

[26] GPC Direct Testimony at 16:20-22 and 17:6-8.

A: FT utilized by RTP customers remains included in the FCR, with full cost recovery from FCR customers. Georgia Power argues that even though RTP customers do not directly pay for FT costs through the RTP fuel credit calculation, they make up for it by paying these costs as part of base rates. It appears that Georgia Power views FT costs as a form of capital substitution.

**Q: DOES GEORGIA POWER HAVE FT FOR ALL ITS PEAKER PLANTS?**

A: Yes. Georgia Power panel testimony implied that peaking resources don't include "much FT," and that it is baseload resources that require FT.[27] But in fact, according to data filed by Georgia Power and its affiliates, every methane gas plant operated by Southern Company has FT contracts.[28]

**Q: IS IT CORRECT TO CONSIDER FT COSTS A FORM OF CAPITAL SUBSTITUTION?**

A: No. Capital substitution in the peaker theorem refers to the substitution of capital cost to achieve a lower fuel cost relative to a peaker unit. Since Georgia Power's peaker units contract for FT to provide reliable on-peak generation, choosing a higher-cost, higher-efficiency gas plant does not result in reducing FT cost relative to a peaker unit.

In a typical IRP evaluation, the cost of a new peaker unit would include fuel and other variable costs, the capital cost of the plant itself, and FT costs. In a correct application of the peaker theorem, all of these costs would be recovered during peak hours through either

[27] Hearing Transcript at 111:9.
[28] EIA Form 923, Schedule 5.

lambda (when the peaker is dispatched on the margin) or through the reliability cost component of the RTP rate.

**Q: SO DOES THE RTP RATE RECOVER FT COSTS?**

A: This is questionable. It is clear that Southern Company does not include FT cost in lambda, so this leaves the reliability capacity cost component of the RTP rate as the only source of revenues that could cover these costs during peak hours. As discussed above, it is not clear whether or not FT or any other type of fixed fuel delivery cost is, in fact, included in Georgia Power's marginal value of capacity.

Furthermore, even if FT costs are included in Georgia Power's marginal value data, it does matter where these revenues are credited. Costs in the FCR are allocated on the basis of energy (MWh) and fixed O&M in base rates are generally allocated on the basis of demand (MW). If the ratio of MWh to MW were the same for all classes, I would agree with Georgia Power. But that ratio, of course, varies, meaning that cost allocation outcomes differ depending on whether FT costs are allocated on the basis of energy or demand.

To resolve these problems, the Commission should revise the RTP fuel credit calculation to include a direct contribution to FT costs.

**Q: WOULD THIS LEAD TO DOUBLE RECOVERY OF FT COSTS?**

A: If FT cost or some similar fuel delivery fixed cost is explicitly included in the data used to determine the marginal value of generation capacity, then including FT costs in the RTP fuel credit calculation would represent double-recovery with revenues recovered by the reliability cost component of the RTP rate.

However, as discussed above, Georgia Power has not provided information on what costs are included in its marginal value of generation capacity. If fixed fuel delivery cost is

included, I would revise my recommendation in one of two ways. If the Commission prefers to keep FT costs in the FCR, then Georgia Power should exclude FT and other fuel delivery fixed costs from the marginal value of generation capacity. Alternatively, the Commission could shift FT cost recovery to base rates, with those identified as caused by large loads being directly allocated to those customers and the remainder allocated on the same basis as other generation O&M costs.

**Q: WHY DON'T YOU AGREE WITH GEORGIA POWER'S PROPOSED COST ALLOCATION FACTOR FOR FT COSTS?**

A: Georgia Power proposes to use a winter 1CP factor to allocate new FT costs between large load customers and other growth. In live testimony, Georgia Power's witnesses were unable to identify any other costs that are currently allocated using a 1CP allocation factor.[29]

Georgia Power argues that its proposal is "consistent with the capacity need that drove the incremental generation resources and the allocation in the large load cost model."[30] Georgia Power's witnesses referred to a joint letter filed with Commission Staff stating that the "existing large load contract portfolio protects non-large load customers from bearing any of the costs of serving new large load customers."[31] But when Georgia Power's panel was asked whether all costs in the large load cost model are allocated on a single winter coincident peak, the panel refused to answer that question on the basis of confidentiality.[32]

[29] Hearing Transcript at 161:20-162:16.
[30] GPC Direct Testimony at 17:8-10; Hearing Transcript at 161:15-19.
[31] Hearing Transcript at 172.
[32] *Id.* at 171.

Georgia Power provided the allocation factor by year on a trade secret basis in response to Commission Staff Hearing Request 1-1, but the response did not provide any basis for the calculation of the allocation factor.

Thus, it appears that Georgia Power's large load cost model uses a winter 1CP allocation factor for some purposes, and it may be that that Commission Staff agree that this is an appropriate cost allocation factor as it is used in the model. But Staff does not express an opinion on the cost allocation factor in the joint letter.[33]

And further, Georgia Power's assertion that its model uses a winter 1CP allocation factor, nor any information on how it is used, is not supported by any available evidence in this or any other related proceeding. Georgia Power has consistently refused to allow intervenors any opportunity whatsoever to review the large load cost model it refers to – not even on a trade secret basis.[34]

Georgia Power is requesting that the Commission approve a 1CP allocation factor as the Commission's first decision on how to directly assign costs to large load customers. This would be an unusual if unprecedented use of a 1CP allocation factor, and should be supported by more evidence than indirectly relevant opinions in a joint letter from Georgia Power and the Commission staff. Accordingly, I recommend that the Commission should not approve this proposal at this time.

[33] *See* Joint Statement of the Georgia Public Service Commission Staff and Georgia Power Company Regarding Large Load Contract Deemed filed for purposes of review July 27, 2026, Dkt. 44280 (Aug. 26, 2026).
[34] Hearing Transcript at 170:21-22 and 171:17-18; *see* Order Denying GIPL and Southface Institute's Joint Petition for Access to Trade Secret Information Under a Non-Disclosure Document, Dkt. 56298 (February 26, 2026).

**Q: WHAT ALTERNATIVE TO THE WINTER 1CP COST ALLOCATION METHOD DO YOU PROPOSE?**

A: Since FT is similar to transmission, in that it is required to meet peak demand conditions whenever and for whatever reason they may occur, I recommend that new FT costs be allocated between large load customers and other growth using the same allocation factor as transmission costs. This decision could be made explicitly provisional until the next rate case when a full review of cost allocation methods relevant to large load customers can be considered.

**Q: WHAT FURTHER STEPS SHOULD THE COMMISSION TAKE TO ALLOW FOR A FULL REVIEW OF THIS ISSUE IN THE NEXT RATE CASE?**

A: I recommend that the Commission direct Georgia Power to make a working copy of its large load cost model available to intervenors in this proceeding on a reasonable and protected basis so that I and other experts can be prepared to advise our clients and the Commission on related cost allocation questions. Speaking for myself, I have a clear understanding of the commercial sensitivity of this information and have a well-established track record of maintaining appropriate protection of Georgia Power's trade secrets.

**Q: ARE THERE OTHER FCR COST CATEGORIES WHOSE TREATMENT FOR RTP CUSTOMERS SHOULD BE REVISED?**

A: Yes. The RTP fuel credit "does not incorporate fixed fuel costs, which do not vary with changes in demand."[35] However, while I agree that these costs are not truly "marginal" in

[35] GPC Direct Testimony at 13:4-5.

the sense that they are sensitive to a single kWh increase in demand, these costs do vary with sustained increases in demand.

Coal-related costs are one type of fixed fuel costs that vary with sustained increases in demand, including coal quality penalties and premiums, coal rail car lease, and rail car shortfall/liquidated damages costs. While these costs are "fixed" based on Georgia Power's orders for coal deliveries, it is clearly the case that if coal use increased or decreased by 250%, then there would be some increase or decrease in each of these costs as Georgia Power adjusted the volume of coal delivery orders from suppliers and transportation providers.[36]

A second type of fixed fuel costs that vary with sustained increases in demand is corporate overhead and labor. While these costs are "fixed," within the scope of the FCR, my understanding is that the FCR allocation of these costs varies with annual demand. As fuel costs increase – regardless of whether FCR or RTP customers drive the cost increase – the FCR allocation of corporate overhead and labor costs increases.

**Q: HOW IS RTP CUSTOMER DEMAND AFFECTED BY EXCLUDING FIXED FUEL COSTS FROM THE RTP RATE?**

A: FCR costs can increase because under-pricing the RTP rate can result in an increase in RTP customer demand. In the case of coal-related transportation costs, these "fixed" costs can actually increase if RTP energy use increases by enough to result in, for example, additional rail car leases.

[36] Note that Georgia Power estimated that it would increase coal energy by 264% during the FCR-27 period compared to FCR-26. Direct Testimony of Adam D. Houston and Matthew S. Berrigan on behalf of Georgia Power Company, at 16, Table 3, Dkt. 56765 (Feb. 17, 2026).

In the case of corporate overhead and labor costs, these costs are not likely to be affected by an increase or decrease in energy use by RTP customers. But the amount of these costs included in the FCR appears to be based on total energy use by all customers, including RTP customers.

For example, in March 2025, corporate overhead and labor cost included in FCR was $646,223 compared to just $458,808 for February.[37] Presumably, nearly all of this 41% increase in allocated cost is due to higher fuel consumption in March as compared to February. If these costs had been included in RTP rates, and thus peak RTP rates were further elevated in March, then RTP customers might have reduced demand in response (as the economic theory suggests they would). Reduced RTP demand could have resulted in lower corporate overhead and labor cost allocated for collection through the FCR.

Corporate overhead and labor cost is not included in any of the marginal cost components of the RTP rate.

Even though corporate overhead and labor cost is "fixed" (does not actually vary with dispatch), a failure to include these costs in the RTP rate results in an increase in RTP-customer demand that, then, drives up FCR costs allocated to non-RTP customers. This violates principles of cost causation.

**Q: HOW DO YOU SUGGEST THAT "FIXED" FUEL COSTS BE INCLUDED IN THE RTP FUEL CREDIT?**

A: For each of the categories I have discussed above – "existing" FT, coal costs, and corporate overhead and labor, I recommend that the Commission direct Georgia Power to develop

[37] Georgia Power's Response to STF-JKA-3-6 Attachment PUBLIC DISCLOSURE, Dkt. 57171 (Sept. 3, 2026).

an RTP fuel credit value based on average annual or monthly costs on a per kWh basis, increasing the RTP fuel credit correspondingly.

While this may not represent a perfect credit for the RTP customer share of these costs, it should be reasonably close. Over time, if it is shown that there is material variation in this portion of the RTP fuel revenue credit and actual cost recovery from these customers (as compared to a per kWh cost allocation of these costs on an annual basis), then this method should be reconsidered, as the Commission has done before with the RTP fuel credit.

This will not result in double-recovery, as the rates charged to RTP customers will not change, just the RTP fuel revenue credit. But it will shift revenue credit from base rates to FCR. This will assist in reducing FCR rates for FCR customers, but may increase base rates for those same customers, depending on how other cost allocation questions are handled.

**Q: ARE YOU RECOMMENDING ANY CHANGES TO THE RTP RATE ITSELF IN THIS PROCEEDING?**

A: No, that is out of scope in this proceeding. However, the Commission should consider updating the recovery factor to also include corporate overhead and labor as well as FT, coal-related, and other fixed fuel delivery costs if it is determined that the reliability cost component of the RTP rate does not include these costs. For comparison with Table 1 values above, the 2025 corporate overhead and labor cost allocated to FCR was $5.7 million.[38]

**Q: WHAT COSTS ARE CURRENTLY INCLUDED IN THE RECOVERY FACTOR?**

[38] Georgia Power's Response to STF-JKA-3-6 Attachment PUBLIC DISCLOSURE, Dkt. 57171 (Sept. 3, 2026).

A: As noted above, in its decision in 2000, the Commission stated that the recovery factor (then referred to as an "adder") provides Georgia Power profit and compensation for the risk that advance quotes of RTP prices understate actual prices (potentially resulting in FCR costs that are not recovered from RTP load).[39] In a motion filed by Georgia Power in response to that decision, Georgia Power also stated that the recovery factor "lessens the need to collect for clean air and commitment costs" as well as indirect effects on other costs, and thus it compensates FCR customers for costs that "are not included in the RTP price."[40]

As the recovery factor has not been updated since 2000, it would be appropriate for Georgia Power to identify all costs that may not be recovered through the RTP and propose an update to the recovery factor in the next rate case.

**Q: WHAT FCR COST CATEGORIES SHOULD CONTINUE TO BE EXCLUDED FROM THE RTP FUEL CREDIT METHODOLOGY, AND WHY?**

A: I support excluding fuel-related costs that are not actual costs of fuel (or purchased power) used to generate electricity. This includes gas hedging gains/losses, gas gains/losses on resales, FCR carrying costs, and net renewable program revenues/expenses.

My rationale is that the fuel component of RTP rate revenues should be designed to cover all actual costs of fuel. Costs related to hedging and resales are intended to reduce fuel cost volatility through either financial or physical hedges.

[39] Order, at 6, Dkt. 11708-U In re: Petition for Rule Nisi to Examine Georgia Power Company's Real Time Pricing Structure (May 12, 2000).
[40] Georgia Power Company's Motion for Reconsideration, at 7-8, Dkt. 11708-U (June 22, 2000).

In FCR-27, the Commission limited Georgia Power's natural gas hedging program to 20% of its budgeted natural gas burn for up to 36 months.[41] All hedging settlement costs flow through the FCR process.[42] Hedging also occurs through resales, which represents a physical hedge when fuel is purchased at an advance price and then resold at a later price if the fuel is not needed. Since the RTP customer is expected to experience fuel cost volatility, net costs (or revenues) related to reducing volatility should not be included in the RTP rate.

Similarly, natural gas storage costs should not be included in the RTP rate. It appears to me that Georgia Power's lambda is based on current natural gas market prices, not the price of natural gas as stored and then withdrawn for use. Assuming I understand the lambda calculation correctly, then it appears that natural gas storage functions as a physical hedge for FCR customers and its costs and benefits should accrue to those customers, leaving RTP customers fully exposed to actual fuel cost variability on a day-ahead or real-time basis.

Also similarly, FCR carrying costs are a result of the structure of FCR costs, with rate stability resulting in some months over-recovering and others under-recovering. Because RTP revenues should increase and decrease roughly concurrently with actual fuel use and pricing, RTP customers would not be expected to contribute substantially to FCR carrying costs.

[41] Order Adopting Stipulation, at 5, Dkt. 56765 (Aug. 4, 2026).
[42] Georgia Power's Response to STF-JKA-4-21(c), Dkt. 56765 (March 30, 2026).

Finally, with respect to the net renewable program, under the FCR-27 stipulation, these costs are no longer recovered through the fuel clause and thus the issue is moot.[43]

**Q: HOW DOES LARGE LOAD GROWTH AFFECT GEORGIA POWER'S HEDGING COSTS INCLUDED IN THE FCR RATE?**

A: As noted above, as a result of the settlement in FCR-27, Georgia Power's hedging is capped at 20% of total forecasted methane gas fuel burn. As large load growth impacts Georgia Power's fuel use forecast, it also drives up the amount of hedging, whether physical or financial.

For example, without large load customer demand, Georgia Power would hedge 20% of FCR gas fuel burn. If large load customer demand is forecast to increase total gas fuel burn by 50% for a given period, then hedging would increase proportionately. The result would be an effective increase in the FCR gas fuel cost hedging cap from 20% of FCR gas fuel burn to 30%.

This is not a "cost" necessarily caused by large load demand and imposed on FCR customers, although it has resulted in a cost increase for non-large load customers in FCR-27. Rather it is the effect of the hedging cap design which applies to all gas fuel consumption rather than just consumption forecast to meet FCR customer demand.

While revisiting this issue may be outside the scope of this proceeding, I draw it to the Commission's attention as it is appropriate to exclude load served by RTP customers from the costs and benefits of managing fuel price volatility, and thus it may also be appropriate

[43] Georgia Power's Response to STF-JKA-3-6, Dkt. 57171 (Sept. 3, 2026).

to exclude that load from the limit on gas hedging, particularly in light of the Commission's rules regarding large load cost shifting.

**Q: YOU HAVE NOT DISCUSSED THE INCOME-QUALIFIED DISCOUNT (IQD). DO YOU HAVE A POSITION ON HOW THE COSTS OF THIS PROGRAM SHOULD BE TREATED FOR RTP CUSTOMERS?**

A: It is my understanding that costs of the IQD are primarily collected in base rates, but that a fuel-related portion of the cost is collected in the FCR. It is not clear whether the Commission has considered how to fairly recover IQD costs from incremental load served by RTP customers. A customer taking service on an RTP rate would pay less than the same customer taking service on a non-RTP rate. Certainly it cannot be argued that IQD costs are included in lambda or any concept of capital substitution under the peaker theorem. Resolving this is therefore not a matter of whether these costs should be included in the RTP fuel revenue credit, since these costs are not currently accounted for anywhere in the RTP rate. Given that rates have been set that do not collect IQD costs from incremental RTP load, I do not take a position on this category of costs in this proceeding.

However, I suggest that the Commission direct or that Georgia Power voluntarily agree to develop a fair and reasonable method for allocating a portion of IQD costs to RTP and/or large load customers. The most straightforward method would appear to be a further adjustment to the recovery factor, in addition to those suggested earlier in my testimony, with appropriate allocation of those revenues to both the RTP fuel revenue credit and the balance credited to base rate revenues.

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

A: Yes, it does.

**STATE OF GEORGIA**

**BEFORE THE**

**PUBLIC SERVICE COMMISSION**

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| **In Re:** | ) | |
| | ) | |
| **Real Time Pricing Revenue Credit and** | ) | **Docket No. 57171** |
| **Allocation Methodology** | ) | |

**Exhibit JW-1**

# JOHN D. WILSON

Vice President
Grid Strategies, LLC

## SUMMARY OF PROFESSIONAL EXPERIENCE

*2023–Present* **Vice President, Grid Strategies, LLC**. Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, and regulation. Reviews electric utility prudence, cost allocation and rate design. Designs and evaluates electrification and energy efficiency programs for electric utilities, including cost recovery mechanisms and performance incentives. Evaluates performance of renewable resources and designs performance evaluation systems for procurement. Designs and assesses generation interconnection, load forecasting, resource planning and procurement strategies for regulated and competitive markets.

*2019–23* **Research Director, Resource Insight, Inc.** Same services as above.

*2007-19* **Deputy Director for Regulatory Policy, Southern Alliance for Clean Energy.** Directed regulatory policy, including supervision of experts in areas of energy efficiency, renewable energy, and market data. Provided expert witness testimony to utility regulators. Directed litigation activities, including support of expert witnesses. Represented SACE on numerous legislative, utility, and private committees across a wide range of climate and energy related topics.

*2001–06* **Executive Director, Galveston-Houston Association for Smog Prevention.** Directed advocacy and regulatory policy related to air quality, including ozone, air toxics, and other industrial, utility, and transportation pollutants. Served on the Regional Air Quality Planning Committee, Transportation Policy Technical Advisory Committee, and Steering Committee of the TCEQ Science Committee.

*2000–01* **Senior Associate, The Goodman Corporation.** Provided transportation and urban planning consultant services to cities and business districts across Texas.

*1997–99* **Senior Legislative Analyst and Technology Projects Coordinator, Office of Program Policy Analysis and Government Accountability, Florida Legislature.** Author or team member for reports on water supply policy, environmental permitting, community development corporations, school district financial management and other issues – most recommendations implemented by the 1998 and 1999 Florida Legislatures. Edited statewide government accountability newsletter and coordinated online and internal technical projects.

*1997* **Environmental Management Consultant, Florida State University.** Project staff for Florida Assessment of Coastal Trends.

*1992-96* **Research Associate, Center for Global Studies, Houston Advanced Research Center.** Coordinated and led research for assessments of environmental and resource issues in the Rio Grande / Rio Bravo basin and the Greater Houston region. Coordinated and edited book on climate change in Texas.

## EDUCATION

BA, Physics (with honors) and history, Rice University, 1990.

MPP, John F. Kennedy School of Government, Harvard University, 1992. Concentration areas: Environment, negotiation, economic and analytic methods.

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"Urban Areas," with Judith Clarkson and Wolfgang Roeseler, in Gerald R. North, Jurgen Schmandt and Judith Clarkson, *The Impact of Global Warming on Texas: A Report of the Task Force on Climate Change in Texas*, 1995.

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"Review of NERC's 2025 Long-Term Reliability Assessment," with Adria E. Brooks and Michael Goggin, Grid Strategies LLC, prepared for Earthjustice, NRDC, and Environmental Defense Fund, March 2026.

"Federal Transmission Pricing: The Evolution of Current Policies and Practices," Volumen 1, with Gretchen Kershaw, Rob Gramlich, and Sophie Meyer, Grid Strategies LLC, prepared for the Electricity Customer Alliance and Americans for a Clean Energy Grid, May 2026.

"Federal Transmission Pricing: Options for Ensuring Affordability and Reliability in an Era of High Load Growth," Volume 2, with Sophie Meyer, Gretchen Kershaw, and Rob Gramlich, Grid Strategies LLC, prepared for the Electricity Customer Alliance and Americans for a Clean Energy Grid, June 2026.

## SELECTED PRESENTATIONS

"Clean Energy Solutions for Western North Carolina," presentation to Progress Energy Carolinas WNC Community Energy Advisory Council, February 7, 2008.

"Energy Efficiency: Regulating Cost-Effectiveness," Florida Public Service Commission undocketed workshop, April 25, 2008.

"Utility-Scale Renewable Energy," presentation on behalf of Southern Alliance for Clean Energy to the Board of the Tennessee Valley Authority, March 5, 2008.

"An Advocates Perspective on the Duke Save-a-Watt Approach," ACEEE 5th National Conference on Energy Efficiency as a Resource, September 2009.

"Building the Energy Efficiency Resource for the TVA Region," presentation on behalf of Southern Alliance for Clean Energy to the Tennessee Valley Authority Integrated Resource Planning Stakeholder Review Group, December 10, 2009.

"Florida Energy Policy Discussion," testimony before Energy & Utilities Policy Committee, Florida House of Representatives, January 2010.

"The Changing Face of Energy Supply in Florida (and the Southeast)," 37th Annual PURC Conference, February 2010.

"Bringing Energy Efficiency to Southerners," Environmental and Energy Study Institute panel on "Energy Efficiency in the South," April 10, 2010.

"Energy Efficiency: The Southeast Considers its Options," NAESCO Southeast Regional Workshop, September 2010.

"Energy Efficiency Delivers Growth and Savings for Florida," testimony before Energy & Utilities Subcommittee, Florida House of Representatives, February 2011.

"Rates vs. Energy Efficiency," 2013 ACEEE National Conference on Energy Efficiency as a Resource, September 2013.

"TVA IRP Update," TenneSEIA Annual Meeting, November 19, 2014.

"Views on TVA EE Modeling Approach," presentation with Natalie Mims to Tennessee Valley Authority's Evaluating Energy Efficiency in Utility Resource Planning Meeting, February 10, 2015.

"The Clean Power Plan Can Be Implemented While Maintaining Reliable Electric Service in the Southeast," FERC Eastern Region Technical Conference on EPA's Clean Power Plan Proposed Rule, March 11, 2015.

"Renewable Energy & Reliability," 5th Annual Southeast Clean Power Summit, EUCI, March 2016.

"Challenges to a Southeast Carbon Market," 5th Annual Southeast Clean Power Summit, EUCI, March 2016.

"Solar Capacity Value: Preview of Analysis to Date," Florida Alliance for Accelerating Solar and Storage Technology Readiness (FAASSTeR) meeting, Orlando, FL, November 2017.

"Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement," Southeast Energy and Environmental Leadership Forum, Nicholas Institute for Environmental Policy Solutions, August 2020.

"Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement," Indiana State Bar Association, Utility Law Section, Virtual Fall Seminar, September 2020.

"Resource Adequacy, Reserve Margin, & Seasonal Planning," 2022 Georgia IRP Training and Roundtable Series, February 2022.

"Six Lessons from the PG&E Real Time Pricing Rate Proceeding," 45th Peak Load Management Alliance Conference, April 2022.

"The Era of Flat Power Demand is Over," EFI Foundation, February 2024.

"The Era of Flat Power Demand is Over," 2024 The Energy Authority Energy Symposium, March 2024.

"RTO Generator Interconnection Scorecard," 2024 The Energy Authority Energy Symposium, March 2024.

"The Era of Flat Power Demand is Over," 2024 The Energy Authority Energy Symposium, March 2024.

"Energy Transition Challenges & Opportunities," Panel Member, 2024 The Energy Authority Energy Symposium, March 2024.

"The Era of Flat Power Demand is Over: 2024 'Early Release'," NERC Large Loads Task Force, October 2024.

"Strategic Industries Surging," Midcontinent Power Sector Collaborative, February 2025; Institute for State Policy Leaders, August 2025, and others.

"Forecasting for Large Loads: Current Practices and Recommendations," with Sophie Meyer, Energy Systems Integration Group webinar, December 2025.

"Increasing the Certainty and Transparency of Load Forecasts," NASEO 2026 Energy Policy Outlook Conference, February 2026.

"Advancing Long-Term Forecasting for Large Loads," NARUC Bulk Power System Virtual Training Series: Processing Large Load Interconnection Requests, April 2026.

Panelist, Federal Energy Regulatory Commission Technical Conference on Increasing Market and Planning Efficiency Through Improved Software, Docket No. AD10-12-017, July 2026.

## EXPERT TESTIMONY

*2008* **South Carolina PSC** Docket No. 2007-358-E, surrebuttal testimony on behalf of Environmental Defense, the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy and the Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

*2009* **North Carolina UC** Docket No. E-7, Sub 831, direct testimony on behalf of Environmental Defense Fund, Natural Resources Defense Council, Southern Alliance for Clean Energy, and Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

**Florida PSC** Docket Nos. 080407-EG through 080413-EG, direct testimony on behalf of Southern Alliance for Clean Energy and the Natural Resources Defense Council. Energy efficiency potential and utility program goals.

**South Carolina PSC** Docket No. 2009-226-E, direct testimony in general rate case on behalf of Environmental Defense, the Natural Resources Defense Council, the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy and the Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

*2010* **North Carolina UC** Docket No. E-100, Sub 124, direct testimony on behalf of Environmental Defense Fund, the Sierra Club, Southern Alliance for Clean Energy, and Southern Environmental Law Center. Adequacy of consideration of energy efficiency in Duke Energy Carolinas and Progress Energy Carolinas' 2009 integrated resource plans.

**Georgia PSC** Docket No. 31081, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2010 integrated resource plan, including cost effectiveness, rate and bill impacts, and lost revenues.

**Georgia PSC** Docket No. 31082, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2010 demand side management plan, including program revisions, planning process, stakeholder engagement, and shareholder incentive mechanism.

*2011* **South Carolina PSC** Docket No. 2011-09-E, allowable ex parte briefing on behalf of Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, and Upstate Forever. Adequacy of South Carolina Electric & Gas's 2011 integrated resource plan, including resource mix, sensitivity analysis, alternative supply and demand side options, and load growth scenarios.

**South Carolina PSC** Docket Nos. 2011-08-E and 2011-10-E, allowable ex parte briefing on behalf of Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, and Upstate Forever. Adequacy of Progress Energy Carolinas and Duke Energy Carolinas' 2011 integrated resource plans, including resource mix, sensitivity analysis, alternative supply and demand side options, cost escalation, uncertainty of nuclear and economic impact modeling.

*2013* **Georgia PSC** Docket No. 36498, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2013 integrated resource plan, including cost effectiveness, rate and bill impacts, and lost revenues, economics of fuel switching and renewable resources.

**South Carolina PSC** Docket No. 2013-392-E, direct testimony with Hamilton Davis in Duke Energy Carolinas need certification case on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. Need for capacity, adequacy of energy efficiency and renewable energy alternatives, and use of solar power as an energy resource.

*2014* **South Carolina PSC** Docket No. 2014-246-E, direct testimony in generic proceeding on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. Methods for calculating dependable capacity credit for renewable resources and application to determination of avoided cost.

*2015* **Florida PSC** Docket No. 150196-EI, direct testimony in Florida Power & Light need certification case on behalf of Southern Alliance for Clean Energy. Appropriate reserve margin and system reliability need.

*2016* **Georgia PSC** Docket No. 40161, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of renewable energy in Georgia Power's 2016 integrated resource plan, including portfolio diversity, operational and implementation risk, analysis of project-specific costs and benefits (including location and technology considerations), and methods for calculating dependable capacity credit for renewable resources.

*2019* **Georgia PSC** Docket Nos. 42310 and 42311, direct testimony with Bryan A. Jacob in Georgia Power's 2019 integrated resource plan and demand side management plan on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of renewable energy in IRP, retirement of uneconomic plants, and use of all-source procurement process. Shareholder incentive mechanism for both renewable energy and DSM plan.

*2020* **Nova Scotia UARB** Matter No. M09519, direct testimony with Paul Chernick in Nova Scotia Power's application for approval of the Smart Grid Nova Scotia Project on behalf of the Nova Scotia Consumer Advocate. Cost classification,

decommissioning costs, justification for software vendor selection, and suggested changes to project scope.

**Nova Scotia UARB** Matter No. M09499, direct testimony with Paul Chernick in Nova Scotia Power's 2020 annual capital expenditure plan on behalf of the Nova Scotia Consumer Advocate. Potential to decommission hydroelectric systems, review of annually recurring capital projects, use of project contingencies, and cost minimization practices.

**Nova Scotia UARB** Matter No. M09579, direct testimony with Paul Chernick in Nova Scotia Power's application for the Gaspereau Dam Safety Remedial Works on behalf of the Nova Scotia Consumer Advocate. Alternatives to proposed project, project contingency factor, estimation of archaeological costs, and replacement energy cost calculation.

**Nova Scotia UARB** Matter No. M09707, direct testimony with Paul Chernick on Nova Scotia Power's 2020 Load Forecast on behalf of the Nova Scotia Consumer Advocate. Impacts of recession, application of end-use studies, improvements to forecast components, and impact of time-varying pricing.

**California PUC** Docket A.19-10-012, direct and rebuttal testimony with Paul Chernick in San Diego Gas & Electric's application for the Power Your Drive Electric Vehicle Charging Program on behalf of the Small Business Utility Advocates. Ensuring that utility-installed chargers advance California goal for electric vehicles. Budget controls. Reporting requirements. Evaluation, monitoring and verification processes. Outreach to small business customers.

**California PUC** Docket A.19-08-013, direct testimony in Southern California Edison's 2021 general rate case (track 2) on behalf of the Small Business Utility Advocates. Reasonableness of remedial software costs to be included in authorized revenue requirement.

**Georgia PSC** Docket Nos. 4822, 16573 and 19279, direct, rebuttal and surrebuttal testimony in Georgia Power Company's PURPA avoided cost review on behalf of the Georgia Large Scale Solar Association. Reviewing compliance with prior Commission orders. Application of capacity need forecast in projection of avoided capacity cost. Calculation of cost of new capacity. Proposal of standard offer contract.

**California PUC** Docket A.19-11-019, direct, reply, responsive, and reply to responsive testimony with Paul Chernick in Pacific Gas & Electric's 2021 general rate case (phase 2) on behalf of the Small Business Utility Advocates. Cost of service methods. Rate design, including customer charges, demand charges, real time pricing tariffs, TOU differentials and periods.

**Nova Scotia UARB** Matter No. M09548, direct testimony on the audit of Nova Scotia Power's Fuel Adjustment Mechanism on behalf of the Nova Scotia Consumer Advocate. Reasonableness of fuel contract costs. Scope of study on

dispatch practices. Impact of greenhouse gas shadow pricing. Compliance issues related to resource planning.

*2021* **California PUC** Docket R.20-11-003, direct and reply testimony on rulemaking to ensure reliable electric service in the event of an extreme weather event on behalf of the Small Business Utility Advocates. Modifications to Critical Peak Pricing programs and Time of Use periods. Modifications to load management programs.

**Nova Scotia UARB** Matter No. M09898, direct testimony on Nova Scotia Power's Annually Adjusted Rates on behalf of the Nova Scotia Consumer Advocate. Effect of delays in power contract. Unit modeling assumptions. Variable capital costs. Application of Time-Varying Pricing.

**Nova Scotia UARB** Matter No. M09920, direct testimony on Nova Scotia Power's Annual Capital Expenditure Plan for 2021 on behalf of the Nova Scotia Consumer Advocate. Cost minimization. Project contingency. Economic analysis model. Analysis of specific projects.

**Nova Scotia UARB** Matter No. M09777, direct testimony with Paul Chernick on Nova Scotia Power's Time-Varying Pricing Tariff Application on behalf of the Nova Scotia Consumer Advocate. Effect of proposed TVP tariffs on load, capacity savings, and energy costs. Recommended CPP tariffs. Treatment of demand charges in TVP tariffs. Implementation and evaluation of TVP tariffs. Lost revenue adjustment mechanism.

**South Carolina PSC** Docket Nos. 2019-224-E and 2019-225-E, surrebuttal testimony on 2020 Integrated Resource Plans filed by Duke Energy Carolinas and Duke Energy Progress. All-source procurement process. Process for resolution of disputed issues in IRP proceedings.

**California PUC** Docket A.20-10-011, direct and reply testimony with Paul Chernick in Pacific Gas & Electric's Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot on behalf of the Small Business Utility Advocates. Rate design for real time pricing tariff. Marketing to small businesses. Evaluation plan.

**California PUC** Docket R.20-08-020, direct and reply testimony with Paul Chernick in rulemaking to revisit net energy metering (NEM) tariffs on behalf of the Small Business Utility Advocates. Rate design for NEM tariff. Method for analyzing NEM tariff program.

**California PUC** Docket A.20-10-012, direct testimony with Paul Chernick in Southern California Edison's 2021 general rate case (phase 2) on behalf of the Small Business Utility Advocates. Cost of service methods. Rate allocation and design, including customer charges and real time pricing tariffs.

**Nova Scotia UARB** Matter No. M10176, direct testimony on Nova Scotia Power's Smart Grid Nova Scotia Solar Garden Pilot Rate Rider on behalf of the

Nova Scotia Consumer Advocate. Addressing risks associated with future cost changes.

**Nova Scotia UARB** Matter No. M10110, direct testimony on Nova Scotia Power's Wreck Cove hydroelectric project on behalf of the Nova Scotia Consumer Advocate. Reasonableness of project and unresolved issues.

**California PUC** Docket A.19-08-013, direct testimony in Southern California Edison's 2021 general rate case (track 3) on behalf of the Small Business Utility Advocates. Reasonableness and prudence of remedial and replacement software costs to be included in authorized revenue requirement.

**Nova Scotia UARB** Matter No. M10197, direct testimony on Nova Scotia Power's Tusket Main Dam Refurbishment Authorization to Overspend application on behalf of the Nova Scotia Consumer Advocate. Whether the project should proceed and whether full cost recovery is justified.

**Colorado PUC** Proceeding No. 21AL-0317E, answer testimony in Public Service Company of Colorado's 2021 general rate case (phase 1) on behalf of Energy Outreach Colorado. Reasonableness of capital project costs, choice of test year, adjustment to load to reflect effects of pandemic.

*2022* **California PUC** Docket A.21-05-017, direct testimony with Paul Chernick in Liberty Utilities Calpeco 2022 general rate case on behalf of the Small Business Utility Advocates. Marginal cost study, revenue allocation, rate design.

**Nova Scotia UARB** Matter No. M10366, direct testimony on Nova Scotia Power's Annual Capital Expenditure Plan for 2022 on behalf of the Nova Scotia Consumer Advocate. Alignment with IRP and new regulation. Cost minimization. Project contingency. Post-project review. Total cost of ownership. Economic analysis model. Decommissioning. Analysis of specific projects.

**California PUC** Docket A.21-10-010, direct testimony on Pacific Gas and Electric's proposed Electric Vehicle Charge 2 Program on behalf of the Small Business Utility Advocates. Program scale and unit costs. Cost controls. Cost Allocation.

**Nova Scotia UARB** Matter No. M10569, direct testimony on Nova Scotia Power's 2022 Load Forecast Report on behalf of the Nova Scotia Consumer Advocate. Impact of multi-hour average temperatures and wind speed on load. Use of multiple weather stations in load forecast. Electrification forecast. Load Research Sample model. DSM adjustment.

**Nova Scotia UARB** Matter No. M10400, direct testimony on Nova Scotia Power's Work Management and Scheduling & Dispatch Application on behalf of the Nova Scotia Consumer Advocate. Economic analysis. Additional applications for software. Contingency guidelines. Total cost of ownership.

**Massachusetts DPU** Docket No. 22-22, direct, surrebuttal and supplemental testimony on Eversource Energy's 2022 Base Distribution Rate Case on behalf of the Cape Light Compact. Allocation of distribution revenue requirement.

**Nova Scotia UARB** Matter No. M10431, direct testimony on Nova Scotia Power's 2022 General Rate Application on behalf of the Nova Scotia Consumer Advocate. Board directives. Fuel costs. Capital project revenue requirements. Deferral accounts and riders. Cost allocation. Residential customer charge.

*2023*

**Nova Scotia UARB** Matter No. M10959, direct testimony on Nova Scotia Power's 2023 Application for Annually Adjusted Rates on behalf of the Nova Scotia Consumer Advocate. Seasonal and time-varying rates. Impact of Maritime Link power delivery. Cost of service study updates.

**California PUC** Docket R.22-07-005, direct testimony on Rulemaking to Advance Demand Flexibility Through Electric Rates. Income-graduated fixed charge: cost categories, rate design, and impacts on electrification, low-income ratepayers, and energy efficiency.

**Nova Scotia UARB** Matter No. M10960, direct testimony on Eastward Energy's 2023 General Rate Application on behalf of the Nova Scotia Consumer Advocate. System Expansion Investments. Customer connection incentive program. Impacts on electrification programs.

**Nova Scotia UARB** Matter No. M10416, direct testimony on the audit of Nova Scotia Power's Fuel Adjustment Mechanism on behalf of the Nova Scotia Consumer Advocate. Reasonableness of biomass fuel costs. Shortfall in expected customer benefits from Maritime Link transmission project. Regional joint dispatch. Accounting issues related to coal supplies and wind farm tax credits. Impact of demand response and time-varying rates on fuel costs.

**Nova Scotia UARB** Matter No. M11009, direct testimony on the disposition of the Nova Scotia Power Maritime Link Inc's Holdback. Benefits of Maritime Link, including energy- and capacity-related benefits. Offset of replacement energy costs. Sufficiency of regulatory process to recover customer benefits.

**Nova Scotia UARB** Matter No. M11017, direct testimony on Nova Scotia Power's Annual Capital Expenditure Plan for 2023 on behalf of the Nova Scotia Consumer Advocate. Capital projects with risk. Reliability investments. Cost minimization practices, including project contingency, total cost of ownership, project delivery model, and post-project reviews. Analysis of specific projects.

**Kentucky PSC** Case No. 2022-00402, direct testimony on Kentucky Utilities and Louisville Gas and Electric's application for the retirement of seven fossil-fired generation units on behalf of Metropolitan Housing Coalition, Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association. Demonstration that retirement of units meets statutory standard to overcome rebuttable presumption against retirement. Consideration

of utility replacement portfolio and membership in PJM. Definition of dispatchable electric generating capacity. Use of dispatch practices including full flexibility operating mode for renewables. Updates to resource adequacy methods. Economic test for investment in small-frame CT units.

**Nova Scotia UARB** Matter No. M11108, direct testimony on Nova Scotia Power's 2023 Load Forecast Report on behalf of the Nova Scotia Consumer Advocate. Use of lagged temperatures and wind speed to forecast/normalize load. Use of multiple weather stations in load forecast. Electrification forecast, including backup to heat pumps and electric vehicle demand. Load research sample model. DSM adjustment.

**Washington UTC** Docket No. UE-230172, response and cross-answer testimony on PacifiCorp's 2024 General Rate Case on behalf of the WUTC Staff. Net power costs. Revision to power cost adjustment mechanism (PCAM).

*2024* **Nova Scotia UARB** Matter No. M11017, direct testimony on Nova Scotia Power's Annual Capital Expenditure Plan for 2023 on behalf of the Nova Scotia Consumer Advocate. Capital projects with risk. Reliability investments. Distribution routine budgets. IT routine budgets. Cost minimization practices, including project contingency, project delivery model, post-project reviews, and quality control. Analysis of specific projects.

**Nova Scotia UARB** Matter No. M11621, direct testimony on Nova Scotia Power's Smart Grid Nova Scotia Final Report on behalf of the Nova Scotia Consumer Advocate. Classification of capital expenditures. Completion of business plan.

**Washington UTC** Docket No. UE-240006, response and cross-answer testimony on Avista's 2024 General Rate Case on behalf of the WUTC Staff. Net power expenses. Impact of carbon emissions policy. Revision to energy recovery mechanism (ERM).

**Nova Scotia UARB** Matter No. M11689, direct testimony on Nova Scotia Power's 2024 Load Forecast Report on behalf of the Nova Scotia Consumer Advocate. Consideration of weather trends. Hybrid scenario for electrification. Forecast for peak demand impact of time-varying pricing tariffs. Forecast peak demand for electric vehicle charging. Inconsistencies between load forecast and distribution planning.

**Washington UTC** Docket No. UE-240004, response and cross-answer testimony on Puget Sound Energy's 2024 General Rate Case on behalf of the WUTC Staff. Net power costs. Impact of carbon emissions policy. Prudency of power purchase agreement.

**Nova Scotia UARB** Matter No. M11533, direct testimony on the audit of Nova Scotia Power's Fuel Adjustment Mechanism on behalf of the Nova Scotia Consumer Advocate. Regional joint dispatch. Net benefits of hedging.

Recommended disallowances related to maintenance, human error, and uneconomic dispatch issues.

*2025* **Nova Scotia UARB** Matter No. M11150, direct testimony on Nova Scotia Power's Appeal of Minister's Decision on behalf of the Nova Scotia Minister of Energy. Lack of independent assessment of project schedule. Due diligence in compliance with renewable energy standard.

**Nova Scotia UARB** Matter No. M11989, direct testimony on Nova Scotia Power's 2025 Application for Annually Adjusted Rates on behalf of the Nova Scotia Consumer Advocate. Forecasts of power imports. Impact of scheduling uncertainty for new generation. Seasonal and time-varying rates. Stakeholder engagement on updating methods.

**Nova Scotia UARB** Matter No. M12012, direct testimony on Nova Scotia Power's Annual Capital Expenditure Plan for 2025 on behalf of the Nova Scotia Consumer Advocate. Capital projects with insufficient support. Reliability investments. Cost minimization practices, including project contingency, project delivery model, post-project reviews, and Mersey Hydro. Progress on planned renewable resources.

**Louisiana PSC** Docket No. 37425, answer testimony on Entergy Louisiana's Application for Approval of Generation and Transmission Resources in Connection with Service to Single Customer on behalf of the Southern Renewable Energy Association. Compliance with Commission orders. Failure to evaluate renewable and storage resources. Corporate sustainability rider and expedited certification process.

**Colorado PUC** Proceeding No. 24A-0442E, answer and cross-answer testimony on Public Service Company of Colorado's 2024 Just Transition Solicitation on behalf of Interwest Energy Alliance. Just Transition incentives. Utility ownership target. Bid flexibility. Transmission planning. Procurement contingencies. Systemic risks to generation developers.

**Washington UTC** Docket No. UE-250224, response and cross-answer testimony on PacifiCorp's 2025 General Rate Case on behalf of the WUTC Staff. Net power costs, including adjustments and allocation factors. Changes from dynamic to fixed allocation factors. Hedging and market transaction costs. WEIM benefits calculation method.

**Georgia PSC** Docket No. 44280, direct testimony on Georgia Power Company's stipulation on extending its alternate rate plan on behalf of Natural Resources Defense Council, Sierra Club, and the Southern Alliance for Clean Energy. Sufficiency of information and opportunity for review. Assurances regarding impact of large loads on existing customer rates. Need for an illustrative cost of service study.

**Virginia SCC** Case No. PUR-2025-00058, direct and surrebuttal testimony on Dominion Virginia's 2025 rate case on behalf of Appalachian Voices. Minimum system method and monthly customer charges. Review of proposed new large energy user rate class and related standard energy service agreement terms. Generation and transmission cost allocation methods.

**South Carolina PSC** Docket No. 2025-154-E, direct and surrebuttal testimony on Duke Energy Progress's 2025 rate case on behalf of South Carolina Coastal Conservation League and three other organizations. Large load tariffs and contract terms. Generation and transmission cost allocation methods. Treatment of interruptible load.

**South Carolina PSC** Docket No. 2025-172-E, direct and surrebuttal testimony on Duke Energy Carolinas' 2025 rate case on behalf of South Carolina Coastal Conservation League and three other organizations. Large load tariffs and contract terms. Generation and transmission cost allocation methods. Treatment of interruptible load.

**North Carolina UC** Docket Nos. E-2, Sub 1383 and E-7, Sub 1332, direct testimony on Duke Energy's proposal to combine its two operating companies on behalf of the Southern Alliance for Clean Energy and three other organizations. Rate consolidation, including jurisdictional cost allocation effects. Large load tariff. Cost minimization strategy.

*2026* **South Carolina PSC** Docket No. 2025-230-E, direct and surrebuttal testimony on Duke Energy's proposal to combine its two operating companies on behalf of the South Carolina Coastal Conservation League and three other organizations. Rate consolidation, including jurisdictional cost allocation effects. Large load tariff. Class allocation of jurisdictional revenue sharing. Cost minimization strategy.

**Nova Scotia EB** Matter No. M12012, direct testimony on Nova Scotia Power's Annual Capital Expenditure Plan for 2026 on behalf of the Nova Scotia Consumer Advocate. Cost forecasting and minimization in distribution routine capital projects. Reliability investments. Revisions to capital cost estimate practices.

**Nova Scotia EB** Matter No. M12691, direct testimony on Eastward Energy's 2026 General Rate Application on behalf of the Nova Scotia Consumer Advocate. Marketing and sales cost allocation. CRP deferral cost recovery.

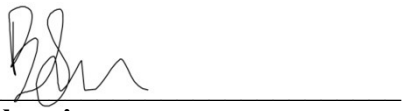
**North Carolina UC** Docket No. E-7, Sub 1329, direct testimony on Duke Energy Carolinas' 2025 general rate case on behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Southern Alliance for Clean Energy, and Vote Solar. Jurisdictional and class allocation of generation and transmission costs. Large load tariff. Minimum system method use in class allocation of distribution costs.

**North Carolina UC** Docket No. E-2, Sub 1380, direct testimony on Duke Energy Progress' 2025 general rate case on behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Southern Alliance for Clean Energy, and Vote Solar. Jurisdictional and class allocation of generation and transmission costs. Large load tariff. Minimum system method use in class allocation of distribution costs.

**Nova Scotia EB** Matter No. M12861, direct testimony on Nova Scotia Power's 2026 Load Forecast Report on behalf of the Nova Scotia Consumer Advocate. Residential heating intensity. Hybrid scenario for electrification. Demand reduction programs, including direct load control, time varying pricing and business, non-profit and institutional curtailment.

## CERTIFICATE OF SERVICE

I certify that the foregoing **Direct Testimony of John D. Wilson on behalf of Georgia Interfaith Power & Light, Park Avenue Baptist Church, Temple Sinai, and Unitarian Universalist Church of Savannah** was filed with the Public Service Commission in Docket No. 57171 by electronic delivery on the 23rd of September, 2026. An electronic copy of same was served upon all parties listed below by electronic mail as follows:



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