BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

Capacity and Energy Payments to Cogenerators Under PURPA	Docket No. 4822
Georgia Power Company's Green Energy Program	Docket No. 16573

TESTIMONY OF

JOHN D. WILSON

ON BEHALF OF GEORGIA LARGE SCALE SOLAR ASSOCIATION

September 18, 2020

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ATTACHMENTS

I. Identification & Qualifications

Q: Mr. Wilson, please state your name, occupation, and business address.

A: I am John D. Wilson. I am the research director of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and 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 was deputy director of regulatory policy at the Southern Alliance for Clean Energy 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, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, conservation program design, prospective review of capital investment projects, 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 professional qualifications are further summarized in Exhibit JDW-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than twenty times before utility regulators in the Southeast U.S., California and Nova Scotia, including five times before the Georgia Public Service Commission. I have appeared numerous additional times before various regulatory and legislative bodies.

II. Introduction

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Georgia Large Scale Solar Association.

Q: What is the scope of your testimony?

A: The Commission has ordered the reopening of this proceeding to ensure the appropriate valuation of renewable and demand side resources, including a review of the Company's methodology and computation of avoided cost paid to Qualifying Facilities (QFs) pursuant to the Public Utility Regulatory Policies Act (PURPA). I am proposing modifications to Georgia Power's current application of its avoided costs and the methodologies to calculate those avoided costs for QFs.

Q: Why is it appropriate for the Commission to review its prior determination of utility avoided costs?

A: The rapid development of renewable energy, storage, and energy efficiency technologies have significantly changed the cost structure of utilities across the country. These resources have little or no variable cost to dispatch, and their contribution to reliability is not easily expressed as capacity, at least as conventionally defined. Solar power resources are also easily deployed at customer sites, and may qualify as resources under PURPA. Storage and energy efficiency resources are also valued using avoided costs, whether in rates or in program cost-effectiveness evaluations. The opportunity to leverage these resources at or below avoided cost means that Georgia Power can partner with many of its customers to reduce the cost of service to all its customers.

If avoided costs are set too low, then some of these opportunities to partner with customers will be foregone. Foregoing cost-effective opportunities will result in the uneconomic procurement and operation of generation resources by Georgia Power. It is the Commission's responsibility to set avoided costs in a manner that ensures consistency with other decisions that promote safe and reliable electric service at the lowest practicable cost.

Q: What issues do you address?

A: I am addressing four issues. First, the fuel cost component of Georgia Power's projected avoided energy costs are modeled system lambda costs, and the forecast fuel prices for natural gas used in that model are based on Henry Hub market prices. Georgia Power incorrectly omits additional commodity charges that are incurred in the delivery of natural gas to its power plants. Second and third, the fuel cost multiplier and the marginal cost multiplier components of Georgia Power's projected avoided energy costs do not appear consistent with the Commission's 1994 Order. Fourth, Georgia Power's avoided capacity resource is unnecessarily restricted to years with a capacity need identified in the IRP. Georgia Power can derive benefit from capacity supplied by QFs in advance of the need identified in the IRP.

Q: What modifications do you recommend to Georgia Power's current avoided cost methodologies?

A: The Commission should direct Georgia Power to:

- Adjust its forecast fuel prices for natural gas and diesel fuel to account for additional commodity charges and delivery costs,
- Revise its fuel cost multiplier and marginal cost multiplier components to follow the Commission's 1994 Order,
- Include additional capacity benefits in its forecast of capacity value credit, and
- Increase its forecast of capacity value credit based on the economic carrying cost of a combustion turbine.

III. Application of fuel cost forecast in Georgia Power's calculation of the avoided cost of energy.

Q: Please summarize Georgia Power's calculation of fuel costs for the avoided cost of energy.

A: Georgia Power's avoided cost of energy includes six components, including:

- System territorial spot fuel lambda
- Fuel cost multiplier
- Marginal cost multiplier
- Variable O&M component multiplier
- Emissions component adder
- Start-up & commitment component adder

Fuel costs affect the system territorial spot fuel lambda, fuel cost multiplier, and the start-up & commitment component adder.

The system territorial spot fuel lambda is generated by the Company's production cost model and reflects the cost of the last megawatt-hour from marginal unit meeting territorial load in each hour.[1]

The fuel cost multiplier is calculated as the "ratio of blended fuel cost to marginal fuel cost," and both values are outputs of the production cost model.[2] Georgia Power's workpapers indicate that the fuel cost multiplier is a result of conducting two runs of the Company's production cost model, a "marginal run" and a "blended run." A "blend multiplier" is calculated from the ratio of the forecast annual fuel cost for 2020, 2021, and 2022 and is used as the fuel cost multiplier. Beyond 2022, Georgia Power's workpapers demonstrate that the Company does not use a fuel cost multiplier.

The start-up and commitment component adder also includes fuel costs. Georgia Power explains that, "The hourly commitment cost values are derived externally to the production cost model from an extensive calculation based on multiple sensitivity cases that evaluate changes in production costs relative to incremental changes in load."[3] This description appears to indicate that this adder includes not only fuel costs, but also the other production costs (e.g., variable O&M), associated with start-up and commitment costs. Georgia Power has not provided any further explanation of the "extensive calculation based on multiple sensitivity cases," so it was not possible to determine whether this adder is calculated in a reasonable manner.

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[1] Georgia Power, Response to STF-4-1, p. 2.

[2] Georgia Power, Response to STF-4-1, p. 2.

[3] Georgia Power, response to STF-4-1, p. 2.

Q: What fuel cost inputs are used in the Company's production cost modeling?

A: Georgia Power provided its fuel price forecasts for natural gas, delivered coal, and ultra-low-sulfur diesel fuels.[4]

The natural gas fuel price forecast is for Henry Hub gas prices, and is based on a combination of New York Mercantile Exchange (NYMEX) futures settlements and a long term forecast supplied by Charles River Associates. Henry Hub is a natural gas hub that serves as the official delivery location for futures contracts on NYMEX, and settlement prices are used as benchmarks for the North American natural gas market. In order to use that fuel, Georgia Power needs to pay pipeline companies to transport the gas to its plants. Georgia Power did not provide plant-specific delivery charges for natural gas fuel.

The diesel fuel price forecast is labeled as a "retail" fuel price forecast, but is based on wholesale futures prices and a long term wholesale price forecast provided by Charles River Associates. The forecast notes that diesel fuel is "purchased for the plants at wholesale price, not on-highway price." Since the purchase and forecast both reflect a wholesale market orientation, it is unclear why the diesel forecast is labeled "retail." Georgia Power did not provide plant-specific delivery charges for diesel fuel.

Q: Does Georgia Power acknowledge the need to include plant-specific delivery charges for any fuel?

A: Yes. Georgia Power provided plant-specific delivery charges for coal. These charges include "transportation charges (including fuel surcharges and

[4] Georgia Power, response to STF-4-14(a).

relevant transloader fees), Maintenance and Taxes ("M&T") costs (expenses related to railcar use), dust suppression adders (Powder River Basin ("PRB") only), and taxes (Georgia Power only)."[5] I have not reviewed the derivation of those delivery charges.

Q: Do Henry Hub prices reflect the full cost of natural gas to Georgia Power's power plants?

A: No. If Georgia Power purchased fuel at the Henry Hub spot market price, the Company would also incur additional commodity charges to transport the gas along trunk pipelines from Louisiana to locations near its plants, as well as charges to move the gas from the mainlines to the plants. Commodity charges are specified in each pipeline delivery contract; they are imposed on a volumetric basis or on an energy basis.[6]

Q: What commodity charges does Georgia Power pay for natural gas?

A: The Federal Energy Regulatory Commission (FERC) tariffs for Southern Natural Gas Company (SNG) and Transco Gas Pipe Line Company—the major pipelines running from Louisiana to Georgia—include commodity transportation rates and a fuel retention percentage, which covers the shipper's contribution to gas lost or used in operating the pipeline. Georgia Power (or the operators of other natural gas plants included in the Company's production cost model and used in the marginal-cost computation) may pay for transportation with other combinations of commodity charges.

[5] Georgia Power, response to STF-4-14(c).

[6] The energy content for a given volume of pipeline-quality gas does not vary widely. Customers do not receive the specific molecules of methane that are delivered to the pipeline on their behalf; they are more concerned with getting the amount of energy they paid for than the volume of gas.

The current transportation rates and fuel retention percentages for SNG and Transco are summarized in Table 1. For Transco, the transportation rates reflect the additional cost to deliver from Henry Hub in Transco Zone 3 (Louisiana) to a point in Zone 4 (including Georgia). For SNG, transportation rates are similar, except that the SNG system is not directly connected to Henry Hub so there could be an additional transportation rate for delivery from Henry Hub to the SNG pipeline.

Table 1: Southeast Pipeline Commodity Charges

Pipeline	*Interruptible Transportation Rates ($ per MMBtu)*		*Fuel Retention Percentage*
	Minimum Rate	*Maximum Rate*	
SNG	$ 0.024	$ 0.293	3.37 %
Transco	$ 0.025	$ 0.321	1.17 %

Sources: SNG, FERC Tariff, Eighth Revised Volume No. 1, Effective April 1, 2020, Schedule 2.3.1. Transportation charge is for receipt in Zone 1 to delivery in Zone 3. Fuel retention charge is for SNG Zone 3 as applied April – September. Transco, FERC Gas Tariff, Fifth Revised Volume No. 1, Effective April 1, 2020, Schedules 2.1 and 12.1. Transportation charge is for receipt in Zone 3 to delivery in Zone 4. Fuel retention charge is for Zone 4.

Q: Please provide an example calculation.

A: If the Henry Hub settlement price is $3 MMBtu, and Georgia Power contracts for delivery at a rate of $0.30 per MMBtu via Transco, then the as-delivered price would be:

($3.00 + $0.30) / (100% – 1.17%) = $3.34

In this example, the commodity charges would represent an 11% increase in fuel costs over the Henry Hub spot fuel price.

Q: Can these data be used to adjust Georgia Power's fuel cost forecast?

A: No. Georgia Power has not provided any information regarding its plant-specific natural gas delivery costs. These costs will vary from plant to plant, and may vary with other factors. Georgia Power appears to have firm transportation service at some of its plants, which would affect the structure of the delivery costs. The various plants may purchase gas at a variety of points, both from producers and from marketers, while paying for pipelines and other parties for transportation on a variety of lines. I have provided the tariff data to verify that Georgia Power's avoided cost calculations omit a material component, even though the specific tariffs cannot be readily matched to specific power plants.

Q: Can you estimate Georgia Power's natural gas commodity charges?

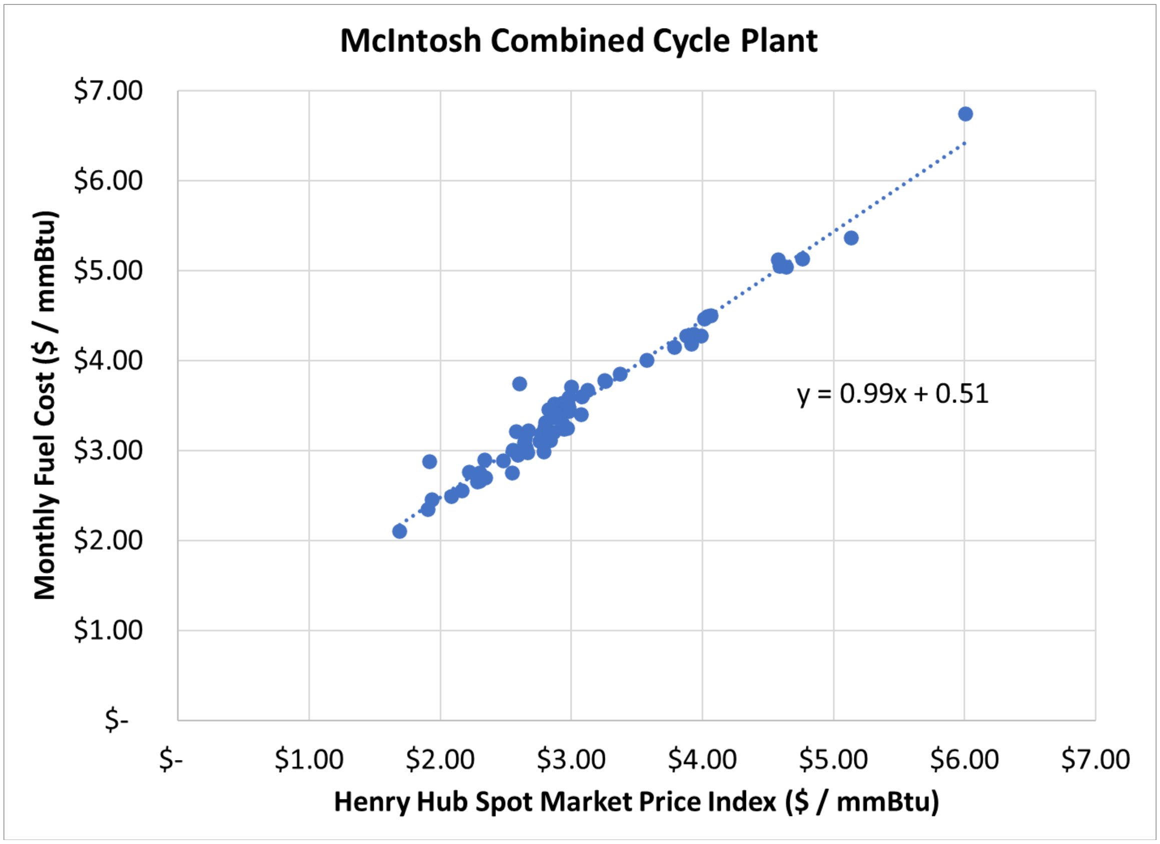
A: Yes, for three plants. Georgia Power reports fuel costs by plant to the US Energy Information Administration (EIA) on Form EIA-923. I reviewed the natural gas fueled plants included in the Company's production cost model[7] and obtained all available fuel cost data for those plants from the EIA.[8] I removed plants that had significant outliers data (e.g., monthly average fuel costs in excess of $100 per MMBtu).

I compared the monthly EIA-923 fuel costs for 2014-2019 for Plants McDonough, McIntosh and Wansley (all combined-cycle plants) with the monthly average of the Henry Hub spot market natural gas price index. As illustrated in Figure 1, there is a very good correlation between the Henry Hub price index and the fuel costs reported by Georgia Power.

[7] Georgia Power, Response to STF-4-1 (Trade Secret Attachment A, tab Blend Multiplier).

[8] Some plants do not report fuel cost data to EIA.

Figure 1: Comparison of Henry Hub Spot Market Price to Reported Fuel Costs for Plant McIntosh, 2014-2019



Even though the correlation between reported fuel costs and the Henry Hub spot market price is very good, there are three differences worth pointing out. First, there are a few outlier points. This could be an artifact of the averaging in certain months. For example, if Plant McIntosh happened to run more on the November 2019 days that happened to have higher-than-average gas prices for that month, its monthly average cost might be higher than the average Henry Hub price index for the month.

Second, the monthly fuel cost increases by only $0.99 for every $1.00 increase in the Henry Hub price index. This could also be an artifact of data averaging, or it might reflect the purchases of gas at a point that is less expensive than Henry Hub but has high commodity charges.

Third, Figure 1 shows that fuel costs at Plant McIntosh are $0.51 per MMBtu higher than the Henry Hub price index, regardless of price or volume of sales.

Q: What are the differences between Georgia Power's fuel costs and the Henry Hub price index?

A: As noted above, I am only able to meaningfully compare reported monthly fuel costs to the Henry Hub price index for three Georgia Power gas plants. As illustrated in Table 2, all three have fuel costs that are significantly higher than the Henry Hub price index. I interpret this difference as an estimate of the average commodity charge paid for delivery of natural gas to each plant.

Table 2: Estimated Commodity Charges for Three Georgia Power Gas Plants, 2014-2019

Gas Plant	*Pipeline*	*Estimated Commodity Charge ($ / MMBtu)*	*Percent Increase in Fuel Price*	
			At $3 / MMBtu	*At $4 / MMBtu*
McDonough	SNG	$ 0.60	20 %	15 %
McIntosh	SNG	$ 0.51	17 %	13 %
Wansley	Transco	$0.19	6 %	5 %

Sources: Natural Gas Intelligence, Bidweek Historical Data for Henry Hub; US EIA Form 923.

It is also interesting to note that even though Plant McDonough and Plant Wansley are located fairly close to each other, the commodity charge for Plant Wansley appears to be much lower. This could be a result of more advantageous contract terms with Transco than those obtained from SNG.

Q: Could this delivery charge be a fixed cost?

A: No. If the delivery charge were a fixed cost, then the difference between Henry Hub and delivered fuel cost per MMBtu would vary inversely with the monthly gas consumption at each plant, with very large costs per MMBtu in months with low usage. The data demonstrate that the commodity charge is driven by monthly fuel use.

Q: Does the fuel cost multiplier adjust the fuel cost forecast to include natural gas fuel commodity charges?

A: No. Since there is no evidence that Georgia Power has included natural gas fuel commodity charges in its production cost model, there is no way that the ratio of two outputs of that model could represent those charges. It is also obvious that this multiplier doesn't represent such charges because it only lasts for three years. These charges are a permanent part of natural gas fuel costs.

Q: How should Georgia Power's avoided cost methodology be revised to include the commodity charge?

A: Georgia Power should review its historical data and contract terms, and determine plant-specific commodity charges. These commodity charges should be applied to the existing fuel price forecast and used in the Company's production cost model when calculating avoided costs.

This will significantly increase the avoided cost of energy. If the three plants analyzed above are representative, then during hours in which gas plants are on the margin, the fuel component of the avoided cost of energy will increase by 5 – 20%. Since Georgia Power has not disclosed how often gas plants are on the margin, or at what costs, it is not possible to estimate the impact of this change on the resulting avoided cost rates.

Q: What about diesel fuel delivery costs?

A: Georgia Power did not provide any explanation of its diesel fuel delivery arrangements (terms or methods). These deliveries have a cost. Even though diesel fuel costs are a very small component of Georgia Power's overall fuel budget, they may be significant at the margin in some hours, and thus could have a significant effect on the avoided cost of energy.

Without information about what diesel fuel delivery arrangements Georgia Power uses, I cannot provide appropriate adjustments to Georgia Power's existing model. Because appropriate adjustments could have a significant effect on the avoided cost of energy, I recommend that the Commission direct Georgia Power to develop a forecast of diesel fuel delivery costs and include it in its calculation of the avoided cost of energy.

Q: Have you provided a spreadsheet model to support this proposed modification?

A: No. To provide a supporting model, I would require access to the Company's production cost model and access to the Company's data on natural gas commodity charges and diesel fuel delivery costs.

The "model" I suggest is to simply add a commodity or delivery charge to the existing fuel cost forecast for each gas and diesel plant included in the Company's production cost model. If Georgia Power lacks these data for any plant, an appropriate estimate could be used.

As an example, I am attaching Exhibit JDW-2 which utilizes a $0.40 per MMBtu assumption for a natural gas commodity charge for all natural gas plants, both existing and proposed future plants. This approach would be reasonable, but a preferred approach would be plant-specific, similar to that used for coal delivery costs.

The explanation I have provided should be entirely sufficient for Georgia Power and the Commission's staff, who have access to the required model and data, to apply this recommended methodology and calculate the alternative results. The startup and commitment costs should also be re-calculated since the fuel cost forecast is an input that affects calculation of those costs.

IV. Application of fuel cost multiplier in Georgia Power's calculation of the avoided cost of energy.

Q: Please summarize the Commission's order establishing the fuel cost multiplier.

A: In 1994, the Commission's order established the details of the current avoided cost methods.[9] It is my understanding that since the 1994 Order was issued, changes to the avoided cost methods have been mainly with respect to the treatment of solar power.[10] In a 2005 Order, the Commission reviewed aspects of the 1994 Order, but I have not located any findings by the Commission that Georgia Power has implemented this order consistent with the direction of the Commission.[11]

In the 1994 Order, the Commission established a fuel cost multiplier because "Georgia Power's initial proposal failed to measure the actual avoided costs of fuel, using only spot market costs." [12] Instead, the Commission agreed with the Adversary Staff's witness Mr. Davie that "QFs will allow the utility to avoid a blend of spot, short-term and long-term fuel contracts."[13] The

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[9] The 1994 Order superseded the avoided cost methodology adopted in 1983 in Docket No. 3252-U. Georgia Public Service Commission, Order in *Capacity and Energy Payments to Cogenerators Under PURPA*, Docket No. 4822-U, October 11, 1994, p. 18. ("1994 Order")

[10] I refer here to solar power rates established in Docket No. 16573 and the RCB Framework, discussed in the testimony of Mr. Arne Olsen.

[11] The main focus of the 2005 Order was the proxy unit method used to allow QFs to participate in RFPs. Order in *Capacity and Energy Payments to Cogenerators Under PURPA*, Docket No. 4822-U, February 18, 2005, p. 11. ("2005 Order")

[12] 1994 Order, p. 14.

[13] Georgia Public Service Commission Staff IRP Adversary Team, *Direct Testimony of Douglas E. Davie*, Docket No. 4822-U (May 27, 1994), p. 38. ("1994 Davie Testimony")

Commission found that avoided energy cost rates should be based on average fuel costs "recorded in the utilities' FCR reports." Georgia Power agreed to the multiplier but disagreed with one detail in Mr. Davie's method.[14]

In 2005, the Commission discussed the fuel cost multiplier further, but did not order any changes. The Commission explained that the "multiplier recognizes and adjusts for the difference between spot fuel prices used for economic dispatch and the average cost of the utility's total fuel portfolio." The Commission then directed further review of the fuel cost multiplier to determine "whether the fuel cost multiplier should be applied to natural gas generation when it is setting the marginal cost."[15] Although there is no record of any further decision by the Commission on this point, it appears that Georgia Power is currently applying the fuel cost multiplier to the system lambda irrespective of fuel.

The 1994 Order provides some, but not all, of the details needed to apply the methodology. Some of the relevant points made in the 1994 Order are that the "multiplier would be updated monthly," that the average fuel costs should exclude "non-fossil fuels and contracts not entered into within the prior 5 years," and that it would be a "5-year factor."[16] Mr. Davie's testimony suggests that the purpose of the monthly update is to maintain consistency with the

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[14] 1994 Order, p. 14.

[15] In a 2005 Order, the Commission ordered, "that the appropriate methodology for determining the fuel cost multiplier requires further review. To That end the Commission directs the Commission Staff to initiate such review." Order in *Capacity and Energy Payments to Cogenerators Under PURPA*, Docket No. 4822-U, February 18, 2005, p. 11. ("2005 Order")

[16] 1994 Order, p. 14.

Company's actual fuel supply portfolios, so this would apply to QFs that are compensated based on actual avoided energy costs rather than a forecast.[17]

Mr. Davie's testimony also indicates that the "5-year factor" was intended to address a concern that the QF should be compensated based on the fuel portfolio based on when the QF made a commitment to the utility, but in the interests of administrative simplification to apply the same fuel cost for all QFs, the fuel portfolio used in the simulation would be limited to those entered within the preceding five years.[18]

Q: Does Georgia Power's forecast of the fuel cost multiplier appear consistent with the 1994 Order?

A: In several respects, the methodology used by Georgia Power does not appear consistent with the 1994 Order. As discussed above, Georgia Power has not provided very much information about how the fuel cost multiplier is forecast. It does appear to be a modeled ratio of average fuel costs to marginal fuel costs based on spot market prices.

However, in several respects, it appears to be different.

- The fuel cost multiplier is forecast for only the first three years covered by the avoided cost rates. There is no indication in the 1994 Order that the Commission intended to limit the duration of its applicability.
- The Company's documentation doesn't indicate whether it excluded non-fossil fuels and legacy contracts from the calculation.

[17] 1994 Davie Testimony, p. 41. I verified that Georgia Power's actual avoided costs include a monthly update of the fuel cost multiplier. Georgia Power, Response to STF-4-6 (Trade Secret Attachment).

[18] 1994 Davie Testimony, pp. 38, 41.

- There is no indication that the fuel cost multiplier uses the "5-year factor" method.

Of these omissions, I am most concerned about the limitation of the multiplier forecast to the first three years. In my review of prior fuel cost multiplier estimates, Georgia Power has consistently forecast the fuel cost multiplier greater than 1.0. This indicates that its forecast fuel portfolio has a higher cost than the spot market.[19] This is reasonable because Georgia Power would want to secure its fuel costs in advance and avoid the risk of high spot market prices. While it may be difficult to forecast this difference into the future, I see no reasonable basis for assuming that the fuel cost multiplier will be 1.0 after 2022.

Q: Is it significant that Georgia Power's current methodology for calculating the fuel cost multiplier may be out of compliance with the 1994 Order?

A: It appears likely to be very significant. Georgia Power files annual updates to the fuel cost multiplier. In the filings I reviewed, the fuel cost multiplier has varied from 1.02 to 1.23. However, Georgia Power's current multiplier is close to or at 1.0 for 2022-2030.[20] Assuming that the Commission intended the fuel cost multiplier to be used for all ten years in the avoided cost projections, then the value of 1.0 for 8 of 10 years may be significantly lower than what the Commission intended in the 1994 Order.

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[19] However, Georgia Power's actual monthly fuel cost multiplier has been less than 1.0 in several recent years. Georgia Power, Response to STF-4-6 (Trade Secret Attachment).

[20] The value for 2022 is provided in a Trade Secret filing only, after 2022 the multiplier is not used. Georgia Power, Response to STF-4-1(a).

Q: Have you provided a spreadsheet model to support this proposed modification?

A: No. I am not proposing a modification to the approved methodology for the fuel cost multiplier. I am proposing that Georgia Power be directed to forecast a fuel cost multiplier that can be applied for each year in the ten year forecast. In order to determine a reasonable fuel cost multiplier, I would need access to the Company's production cost model and data regarding its fuel procurement contracts.

Q: What do you recommend?

A: I recommend that the Commission direct Georgia Power to demonstrate that its fuel cost multiplier is forecast consistent with the 1994 Order. If the Company's recommended fuel cost multiplier forecast differs from the 1994 Order method, the Georgia Power should be directed to explain why and provide a forecast that is consistent with the 1994 Order for review by the Commission and other parties. I also recommend that when details of the fuel cost multiplier forecast are clarified, that there be an opportunity to consider whether this adjustment should be applied in some way to the startup and commitment costs, since those costs also include a fuel cost component.

V. Application of marginal cost multiplier in Georgia Power's calculation of the avoided cost of energy.

Q: Please summarize the Commission's order establishing the marginal cost multiplier.

A: In 1994, the Commission established a marginal cost multiplier because the "territorial system lambda systematically underestimates the full costs avoided by the introduction of a QF." The Commission explained that the lambda "will reflect only the current highest system costs with the QF present; the costs would be higher without the QF energy." The marginal cost multiplier accounts for the "difference between system lambda calculations and actual avoided energy costs."[21]

The order refers to Mr. Davie's testimony for the details needed to apply the methodology. Mr. Davie explains that the multiplier should reflect the "difference between the system lambda cost with the QFs present and the correct energy cost avoided due to the QF."[22] Mr. Davie recommended that the Company should perform two production cost model simulations, one with the QF resources, and one without the QF resources. The difference in cost should then be divided by the QF generation to determine the theoretical unit cost of energy avoided by the QFs, and then divided by the marginal costs from the simulation that includes the QFs to determine the marginal cost multiplier.[23] Georgia Power agreed to use of the multiplier.[24]

Q: Does Georgia Power's current marginal cost multiplier appear consistent with the 1994 Order?

A: No. Georgia Power has provided no explanation or workpapers to support the assumed value of 1.0 for the marginal cost multiplier.[25] My review of Mr. Davie's testimony suggests that the only principled basis for fixing the marginal cost multiplier at 1.0 would be if Georgia Power has no QFs on its system. In fact, Georgia Power currently includes 33 QFs in its annual report,

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[21] 1994 Order, p. 14.

[22] 1994 Davie Testimony, p. 37.

[23] 1994 Davie Testimony, p. 40.

[24] 1994 Order, p. 14.

[25] Georgia Power, Responses to STF-4-1 and STF-4-6.

including 10 QFs that receive monthly capacity payments.[26] Effectively, Georgia Power has eliminated the marginal cost multiplier from the Commission-approved methodology. I am unaware of any proceeding in which this matter has been discussed with the Commission.

Q: Is it significant that Georgia Power's current methodology for calculating the marginal cost multiplier may be out of compliance with the 1994 Order?

A: It appears likely to be very significant. In the 1994 Order, the Commission noted that Mr. Davie estimated the fuel cost multiplier to be "at around 1.02."[27] A 2 % increase in the avoided cost of energy could be significant to a QF.

Q: Have you provided a spreadsheet model to support this proposed modification?

A: No. I am not proposing a modification to the approved methodology for the marginal cost multiplier.

Q: What do you recommend?

A: I recommend that the Commission direct Georgia Power to demonstrate that its marginal cost multiplier assumption of 1.0 is consistent with method and intent of the 1994 Order, or to provide a calculation consistent with the 1994 Order for review by other parties. Once these issues are resolved, I also recommend an opportunity for review of startup and commitment costs to determine whether those costs are affected by the introduction of a QF and, if

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[26] Georgia Power, *Co-Generator/SPP Purchases for July 2020*, Docket No. 1 (August 19, 2020).

[27] 1994 Order, p. 12.

so, whether the marginal cost multiplier should be applied to those costs in any way.

VI. Application of capacity need forecast in Georgia Power's projection of avoided capacity cost.

Q: Please summarize Georgia Power's method for projected avoided capacity cost.

A: Georgia Power describes its method as follows:

> [P]rojected avoided capacity cost is assigned only for years in which the Company's capacity resources are identified as being below the target planning reserve margin. The values in the filing are based on the load forecast and resource assumptions as contained in the Company's Budget 2020 planning cases, which result in a year of capacity need for the Company beginning in 2028.
>
> The value of capacity for years in which the Company's resources are below the target planning reserve margin is based on the Economic Carrying Costs ("ECC") of a Combustion Turbine ("CT").[28]

In its most recent projection of avoided costs, the Company has no capacity need for the years 2021-2027, and then indicates an avoided capacity cost of $57.07 / kW-yr in 2028, with slightly higher values following.[29]

Q: Do you have any concerns about this method?

A: Yes. Capacity has value to a utility and its customers, even if the utility has sufficient capacity to achieve its target planning reserve margin. Georgia Power's economically-optimal reserve margin is based on the ECC of a gas-fueled combustion turbine. If the cost of additional capacity were lower, then

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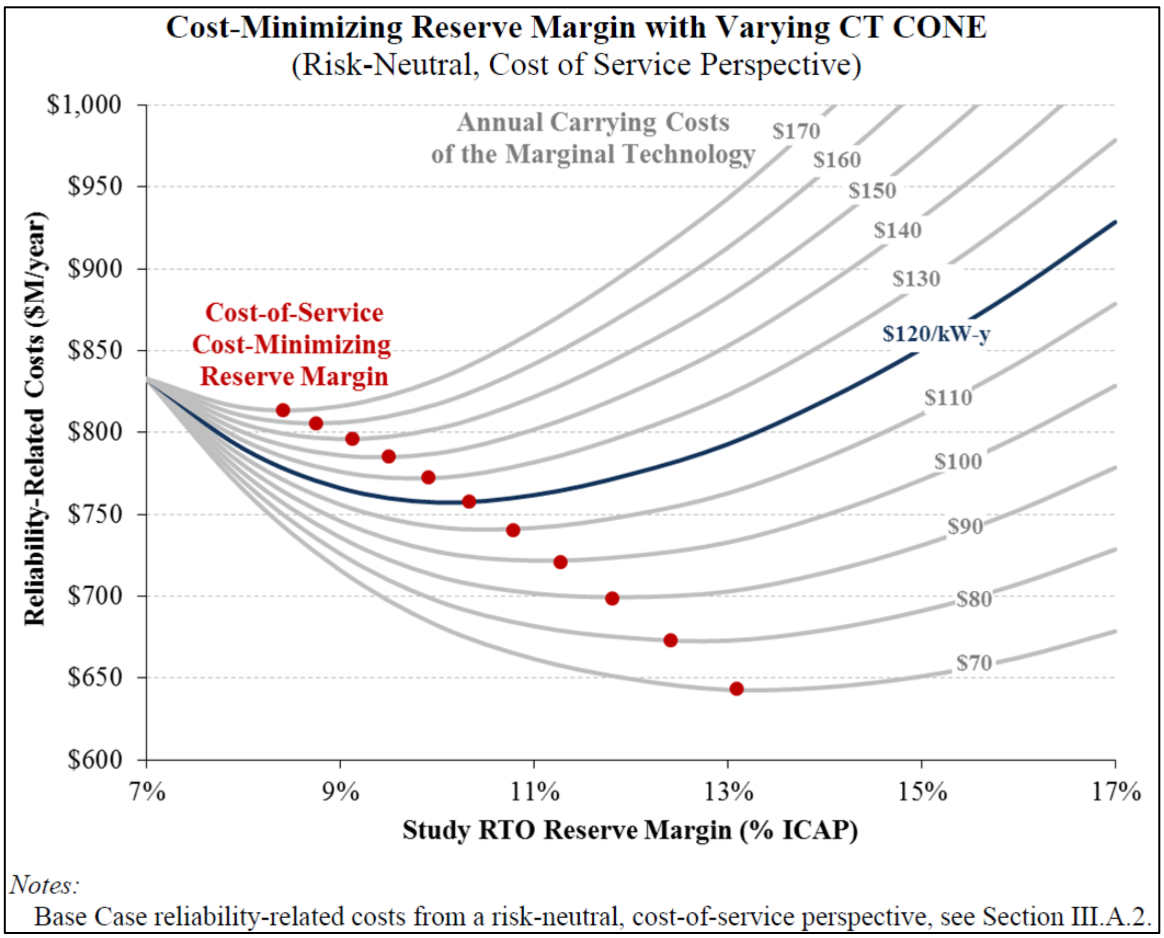
[28] Georgia Power, response to STF-4-1, p. 1.

[29] Georgia Power, *2020 Avoided Cost and Solar Avoided Cost Projections*, Docket Nos. 4822 and 16573 (June 16, 2020).

the economically-optimal target reserve margin would be higher – the utility should optimize by acquiring more capacity.

In other words, "excess" capacity has value to Georgia Power and its customers. That value will be lower than the ECC of a gas-fueled combustion turbine in years in which the target reserve margin is exceeded, but it may often be above zero. The Brattle Group and Astrape Consulting illustrated this effect in a study for FERC, as reproduced in Figure 2 below.

Figure 2: Relationship of Reserve Margin to Capacity Value



Source: The Brattle Group and Astrape Consulting, *Resource Adequacy Requirements: Reliability and Economic Implications*, prepared for the Federal Energy Regulatory Commission (September 2013), p. 90.

As shown in Figure 2, the optimal balance of reliability-related costs and the cost to acquire additional capacity[30] occurs at a different reserve margin depending on the annual carrying costs of the marginal technology. This means that for a given level of forecast reserves, the marginal value of additional capacity can be identified.

For example, if Georgia Power forecast that its target reserve margin is expected to be 30% in 2022, this would be well in excess of its current target reserve margin. Even so, additional capacity should have a value, albeit significantly less than the $57.07 /kW-yr that is forecast for 2028 when the system has a forecast capacity need. That value would be determined in a reserve margin study.

Q: How should Georgia Power determine the avoided capacity cost for years in which it does not have a capacity need?

A: Georgia Power should update its reserve margin study to estimate the reserve margin at 25%, 50%, and 75% of the ECC for a gas-fueled combustion turbine.[31] Then, Georgia Power should determine the avoided capacity cost for a given year by identifying the ECC that corresponds to that year's forecast reserve margin.

In Table 3, I have illustrated this method using hypothetical reserve margins. If the forecast reserve margin for 2022 is 31%, then the avoided capacity cost for 2022 would be $28.54 / kW-yr in this hypothetical example.

[30] In this case, the cost of new entry (CONE) for a gas-fueled combustion turbine (CT).

[31] Or whatever method Georgia Power uses to determine capacity cost.

Table 3: Relationship of Reserve Margin to Capacity Value

Marginal Resource Cost		*Cost-Minimizing Reserve Margin*
Percentage	*ECC ($/kW-yr)*	*(Hypothetical)*
100 %	$ 57.07	26 %
75 %	$ 42.80	28 %
50 %	$ 28.54	31 %
25 %	$ 14.27	35 %

Q: Do customers benefit from excess capacity above the target reserve margin?

A: Yes. Although it should never be policy to target a reserve margin level above an economically-optimal level, there are benefits to customers should Georgia Power's resources exceed the target reserve margin.

First, customers benefit from reduced reliability-related costs. These costs are usually evaluated as costs associated with outages. The target reserve margin is expected to result in infrequent outages related to system-wide resource shortages.[32] Customers are more likely to benefit from a reduced need for Georgia Power to pursue high-cost resource acquisition during periods of regional demand shortages in order to avoid outages. Since fuel and purchased power costs are passed through to customers, avoiding these high costs is a direct benefit to customers resulting from excess capacity above the target reserve margin.

Second, Georgia Power may be able to sell capacity in excess of its target reserve margin on the bilateral market, particularly during periods of regional demand shortages. Revenues from capacity sales benefit customers by offsetting fuel and purchased power costs. While this benefit is not typically captured in a reserve margin study, it does represent real economic value that

[32] Recent experience in California is a reminder that maintaining a target reserve margin does not guarantee generation sufficiency in the face of extreme weather, transmission outages or inconveniently timed outages.

also justifies the recognition of avoided capacity cost in years before Georgia Power has a resource need.

Third, during periods in which Georgia Power has excess capacity resources (for whatever reason), the Company may find it cost-effective to retire some of that excess capacity and reduce its fixed operating and maintenance costs.

Q: Is Georgia Power likely to have an opportunity to retire excess capacity in the near term?

A: Yes. In the 2019 IRP, I testified that Georgia Power should evaluate the cost-effectiveness of Plant Wansley in the 2022-2023 RFP because of its limited value to the Georgia Power system.[33] According to data obtained from the US Energy Information Administration, Plant Wansley units 1 and 2 have operated at capacity factors of less than 35% since 2012.

Furthermore, I testified that Georgia Power's unit retirement study evaluated Plant Wansley in comparison to a combined cycle unit. Considering the low capacity factor of Plant Wansley, this does not appear to be an appropriate evaluation. Georgia Power would not acquire a combined cycle unit to run at a 25-35% capacity factor.

Georgia Power's witnesses testified that retiring Plant Wansley in the suggested timeframe would cause reliability issues, even though the system would be above the reserve target, but did not provide any evidence in support of that assertion.[34]

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[33] Southern Alliance for Clean Energy, *Direct Testimony of John D. Wilson and Bryan A. Jacob*, Docket Nos. 42310 and 42311 (April 25, 2019), p. 16.

[34] Georgia Power Company, *Rebuttal Testimony of Jeffrey R. Grubb, Narin Smith, Michael A. Bush and Jeffrey B. Weathers*, Docket Nos. 42310 and 42311 (May 30, 2019), p. 40.

In the context of setting avoided capacity costs, Georgia Power should conduct a study to determine the earliest date Plant Wansley units 1 and 2 could be retired without causing reliability issues. Then, Georgia Power should determine the capacity value of Plant Wansley for that year by determining how much replacement capacity is needed to provide the same level of reliability as Plant Wansley units 1 and 2 currently provide. These studies should consider the units individually and in combination. The fixed and production cost savings, if any, associated with the replacement of Plant Wansley would be used to calculate an equivalent ECC and thus an avoided cost of capacity.

If those studies identify a capacity value in advance of 2028, and the resulting avoided cost of capacity is greater than the value determined from the reserve margin study method, then Georgia Power should use the result to set the avoided cost of capacity.

Q: What do you recommend?

A: I recommend that the Commission direct Georgia Power to calculate the cost-minimizing reserve margin for marginal capacity costs of 25%, 50%, or 75% of the economic carrying cost of a gas-fueled combustion turbine. Georgia Power should then determine the avoided capacity cost in each year in which there is not a resource need based on matching that economic carrying cost to the forecast reserve margin. Where the economic carrying cost is between the studied values, it should be determined by linear interpolation.

If the forecast planning reserve margin is greater than that associated with 25% of the combustion turbine cost, the benefit of additional capacity should be very low, and might even be set to zero, for simplicity, except where the additional capacity would allow retirement of existing generation.

I also recommend that Georgia Power conduct the necessary studies to determine the avoided cost of capacity associated with the retirement of Plant Wansley units 1 and 2, as described above, and use that avoided capacity cost if it is greater than the amount determine by the reserve margin study method. The same would be true of any other resources that could be economically retired, were additional capacity available.

Q: Have you provided a spreadsheet model to support this proposed modification?

A: No. To provide a supporting model for the reserve margin study method, I would require access to Astrape Consulting's Strategic Energy Risk Valuation Model (SERVM). Southern Company relies on SERVM for its reserve margin studies.

The "model" I suggest is to simply add the ECC of a CT in years without a capacity need, as adjusted using the method described above.

To provide a supporting model for the Plant Wansley capacity value analysis, I would require access to the Company's production cost model software.

The "model" I suggest is to calculate the avoided capacity cost associated with the retirement of Plant Wansley by replacing it with an equivalent amount of new capacity at zero cost, as described above. If that resulting value is greater than the amount suggested by the reserve margin study method for any year(s), then it should be used instead.

The explanation I have provided should be entirely sufficient for Georgia Power and the Commission's staff, who have access to the required model and data, to apply this recommended methodology and calculate the alternative results.

VII. Georgia Power's calculation of the cost of new capacity.

Q: Please summarize Georgia Power's method for calculating the cost of new capacity.

A: As discussed earlier in my testimony, the value of capacity for years in which Georgia Power's resources are below the target planning reserve margin is based on the ECC of a CT. In its most recent projection of avoided costs, the Company has no capacity need for the years 2021-2027, and then indicates an avoided capacity cost of $57.07 / kW-yr in 2028, with slightly higher values following.

This ECC is based primarily on the Company's estimate of the in-service cost of a CT. The Company's estimate also considers operating costs, taxes, financing costs, and firm transportation for fuel.[35]

Q: Is Georgia Power's estimate for the cost of adding new CT capacity consistent with other data sources?

A: No. Georgia Power estimates that the overnight capital cost of a new CT will be [redacted] and that fixed operating & maintenance costs (FOM) will be [redacted]. These estimates are [redacted] than EIA's estimate of $656 /kW for building a new CT in the Southeast and $7.00 /kW-yr for FOM.[36] Since EIA's estimate is provided in 2019 dollars, I applied a capital cost escalator utilized by the company to restate the estimate in the

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[35] Georgia Power, Response to STF-4-1.

[36] Southeast new build frame CT costs are from Table 3 and FOM costs are from Table 1. U.S. Energy Information Administration, *Addendum: Updated Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity Generating Plants in the Electricity Market Module (EMM) of the National Energy Modeling System (NEMS)* (February 5, 2020). Available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_addendum.pdf

appropriate year. I did not change the other assumptions in the Company's ECC worksheet. The resulting ECC for 2028 is $75.47 /kW-yr, which is 32% higher than the avoided capacity cost projected in Georgia Power's 2020 filing.[37] Additional values are presented in Table 4.

Table 4: Recommended Economic Carrying Cost of a Combustion Turbine

ECC of a CT ($/kW-year)	
Year	$/kw-Yr
2020	$ -
2021	$ -
2022	$ -
2023	$ -
2024	$ -
2025	$ -
2026	$ -
2027	$ -
2028	$ 75.47
2029	$ 76.65
2030	$ 77.85

Source: Exhibit JDW-3

Q: Have you provided a spreadsheet model to support this proposed modification?

A: Yes. Exhibit JDW-3 provides a spreadsheet model, with formulas intact and clearly identifying all source data and assumptions. The exhibit primarily references two Trade Secret worksheets provided by Georgia Power and is thus designated as Trade Secret in its entirety.

Q: Does this conclude your testimony?

A: Yes.

[37] Georgia Power, Response to STF-4-1, Attachment A.