STATE OF GEORGIA

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:		
GEORGIA POWER COMPANY'S	**)**	
FUEL COST RECOVERY (FCR-27)	**)**	**DOCKET NO. 56765**
	)	
	)	
	)	
	)	

POST-HEARING BRIEF

SIERRA CLUB, SOUTHERN ALLIANCE FOR CLEAN ENERGY, NATURAL RESOURCES DEFENSE COUNCIL

MAY 14, 2026

INTRODUCTION

Georgia Power's premises in this case are that it is entitled to 100% recovery of fuel costs and that it is under no obligation to prove that its coal dispatching practices are economic. Both premises are invalid. First, O.C.G.A. § 46-2-26 allows for disallowance when the Company's actions were "illegal or clearly imprudent" — but not exclusively in those cases. Since the Commission has disallowed $14.5 million over the last fifteen years without a specific finding of illegality or imprudent activity,[1] then the statute clearly allows for cost sharing between the Company and its ratepayers. Although $14.5 million is a trivial amount in comparison to a conservative estimate of $29 billion dollars spent by Georgia Power on fuel costs during the same period, the Commission's past practice demonstrates that it has statutory authority to limit the Company's recovery.

Second, Georgia Power's testimony regarding its uneconomic dispatch of coal suggests that the Company wants to have its cake and eat it too: it fails to meet its burden to show that its dispatch was in fact economic, while simultaneously seeking to discredit testimony that uses the best available alternative methodology to evaluate whether that dispatch was in fact economic. Intervenors had to use an alternative methodology because the Company does not allow other intervenors (nor Staff) to use its proprietary software to confirm Georgia Power's claims that there were no cheaper available options when it dispatched coal.[2] Using system lambda, which "reflects the marginal cost of the highest cost unit dispatched across the Company's system to meet electricity demand in that hour" and is "the best metric of the marginal cost of producing electricity in that hour," Sierra Club, SACE and NRDC's Witness Michael Goggin found that the Company incurred in $152 million in net losses due to the imprudent dispatch decisions at plants Bowen and Scherer.[3] Disallowance of this amount "will protect ratepayers from shouldering these imprudently incurred costs, and more importantly will incentivize the Company to avoid uneconomic dispatch going forward."[4]

---

[1] *See* Direct Testimony and Exhibits of Jeremy Kalin, SACE, Sierra Club, and NRDC at 14 (Apr. 9, 2026) [hereinafter "Kalin Direct"].
[2] *See* Commissioner Hubbard's questions to Georgia Power's counsel regarding Georgia Power's model at 9:17:29, https://youtu.be/LNMvQS7AkSc?t=33449. *See also* Commissioner Hubbard's questions to Georgia Power's Rebuttal Panel at 42:38, https://youtu.be/-UX1sz7IVQ8?t=2560.
[3] Direct Testimony and Exhibits of Michael Goggin, SACE, Sierra Club, and NRDC at 2 (Apr. 9, 2026) [hereinafter "Goggin Direct"].
[4] *Id.*

To address these issues and to protect ratepayers, the Commission should open an investigatory docket exploring an adequate fuel cost sharing mechanism to take place in Georgia. Alternatively, the Commission may consider fuel cost sharing at the Real Time Pricing (RTP) proceedings proposed in the stipulation entered into between PIA Staff and Georgia Power.[5]

ARGUMENT

1. The Commission Should Implement a Fuel Cost Sharing Mechanism

A. Fuel Cost Sharing in Georgia

The Commission should direct Georgia Power to share a percentage of the fuel costs that the Company seeks to recover in this proceeding. One-hundred percent fuel cost recovery is not mandatory nor set in stone under Georgia law. While Georgia's fuel cost recovery statute allows Georgia Power to pass along all of fuel costs to ratepayers, it does not *require* it. O.C.G.A. § 46-2-26(c) merely directs the utility to propose "base rate tariffs to recover [fuel] costs," but does not mention that costs must be 100% passed through to customers. While O.C.G.A. § 46-2-26(h) establishes that the Commission shall disallow fuel costs that are "the result of illegal or clearly imprudent conduct on the part of the utility," it does not preclude the Commission from disallowing fuel costs on other bases, i.e., as part of a fuel cost sharing mechanism. Commissioner Hubbard correctly identified that the Company and the Commission regularly add and remove costs from the fuel tariff, such as firm transportation or Power Purchase Agreement (PPA) costs. Therefore, the Commission can likewise implement a fuel cost sharing mechanism where shareholders pay a portion of the costs. There is plenty of room under the statute to implement a fuel cost sharing mechanism and, for the reasons discussed over the course of this proceeding, the Commission should do so in this case.

As Sierra Club, SACE and NRDC's Witnesses Michael Goggin and Jeremy Kalin testified in this proceeding, a "moral hazard" occurs when one party is incentivized to take more risk than they normally would because that party is insulated against that risk. Here, "the Company is the agent who makes the decision, but the ratepayer is the principal who pays the cost of that decision."[6] When the consequences of a decision are so disconnected from the

[5] Stipulation, Ga. Pub. Interest Advocacy Staff & Ga. Power Co. at 2, ¶6 (May 12, 2026) [hereinafter "Stipulation"].
[6] Goggin Direct at 21.

decisionmaker that that party takes a bigger risk as a result, a moral hazard exists: "In contrast to merchant generators whose profits are reduced by uneconomic generation, fuel costs do not affect the profits of vertically integrated utilities like the Company, which pass their fuel costs through to their ratepayers in proceedings such as this one."[7] While the Company claims in passing that it already has adequate incentives[8] to reduce fuel costs (it does not), "[a] fuel cost sharing mechanism will incentivize Georgia Power to account for the price risk of natural gas when making decisions about the optimal generation mix."[9] The results of this unchecked policy are palpable in FCR-27:

> The Fuel Cost Recovery mechanism and policy of 100% pass through to ratepayers has incented Georgia Power to rely far too heavily on a single power generation source, leaving a significant portion of the state's electricity supply vulnerable to a disruption from a number of hazards, such severe weather (...) Because utilities do not bear any financial cost or risk responsibilities for fuel, any increase in the cost or the volatility of purchased fuel is not borne by the utility. The Fuel Cost Recovery mechanism provides a utility with a blank check of sorts to increase the throughput of fuel-based generation, even if non-fuel alternatives would provide greater value to ratepayers and greater resource diversity. Once a plant has been granted a certificate of public necessity the equivalent, and absent any disallowance of costs for imprudence or illegal activity, the utility can be assured that all or nearly all of its fossil fuel expenses will be collected from ratepayers, even where the total operating costs of those power plants are now outside of the original economic cost-effectiveness calculation[10].

Georgia Power's direct testimony is replete with indications that the current fuel cost recovery application is a moral hazard: the Company is requesting to recover 100% of its fuel costs from customers, and is expecting to rely more, not less, on gas and coal over the next three years.[11] Indeed, the Company stated that during the FCR-27 test period, "gas fired generation is projected to be the largest energy source for Georgia Power", with "approximately 40% of the

---

[7] *Id.* at 5.
[8] *See* Rebuttal Testimony of Adam D. Houston, Matthew S. Berrigan, Lee Evans & R. John Olson, Ga. Power Co. at 32 (Apr. 23, 2026) ("The Company does not earn a return on fuel costs and is already appropriately incentivized to keep fuel costs low").
[9] *Id.* at 21.
[10] Kalin Direct at 23-24.
[11] *See*, i.e. Direct Testimony and Exhibits of Tom Newsome, Phillip M. Hayet, Anthony Sandonato, Leah J. Wellborn, Ga. Pub. Interest Advocacy Staff at 52, tbl. 18 (Apr. 9, 2026) [hereinafter "Staff Direct"].

projected fuel costs coming from" gas.[12] This percentage will further increase when the Company finishes building the new gas plants at the Bowen, McIntosh, and Wansley sites --gas plants that, during the last two IRP dockets, the Company argued were necessary to meet new data center load. The Company also acknowledged that gas prices are still subject to constant volatility[13] and recognized that factors outside of its control can significantly affect ratepayers.[14] This means more, not less, customer exposure to fuel price increases, prices that customers will be 100% responsible for unless the Commission puts a fuel-risk-sharing mechanism in place.

As Witness Kalin's testimony points out, a fuel-risk-sharing mechanism would allow Georgia Power to set a total fuel budget at the beginning of the rate-setting period based on expected fuel costs" and then:

> [a]t the end of each portion of the rate-setting period . . . if actual costs increase from the approved benchmark, the utility pays a percentage of the difference, passing along such savings to ratepayers by otherwise reducing fuel costs that such customers would have paid. If actual costs decrease, the utility retains a portion of those cost savings as an incentive, with the balance of savings passed along to ratepayers.[15]

Efforts in other states suggest that fuel cost sharing has significant benefits for "reliability, resource diversity, ratepayer protection and utility performance."[16] These factors alone should be enough for the Commission to protect ratepayers from potential fuel price swings by implementing a fuel cost sharing mechanism.

B. Neither the IFR Mechanism nor Hedging Incentivize the Company to Keep Fuel Costs Low

Implementing an Interim Fuel Recovery ("IFR") Mechanism that would authorize Georgia Power to accumulate an under- or over-recovery balance of $300 million (a 50% increase from its current $200 million cap)[17] is not a cost mitigation method. It is undisputed that

[12] Direct Testimony and Exhibits of Adam D. Houston & Matthew S. Berrigan, Ga. Power Co. at 20 (Feb. 17, 2026) [hereinafter "GPC Direct"].
[13] *Id.* at 4.
[14] *Id.* at 9.
[15] Kalin Direct at 16.
[16] *Id.* at 18.
[17] GPC Direct at 22 ("The Company proposes to increase the IFR threshold from the current amount of $200M approved by the Commission to $300M").

ratepayers will not save money from Georgia Power's proposed IFR change. Staff's testimony concluded that customers would benefit from Georgia Power modifying rates as a result of the IFR filing when the IFR is exceeded, not having it left entirely to the Company's undefined discretion.[18] In that limited sense, the Stipulation adequately addresses part of the IFR Mechanism's problem ("When the +/- $300 million threshold is exceeded in either direction, the Company shall, within five days of its IFR notification filing, submit for Commission consideration a proposed IFR rate adjustment to amortize the over- or under-recovered balance over a reasonable and financially prudent period of time"[19]). Yet, rather than reducing fuel costs, increasing the IFR merely passes along the Company's increased fuel costs to ratepayers *sooner*. Georgia Power would be allowed to collect more revenue via the higher FCR tariff, that is, if the Company even decides to file for a change in rates:

> As fuel costs increase and reach the IFR threshold, the Company merely passes along the utility's increased fuel costs to ratepayers. The utility is thus allowed to keep collecting more via the higher FCR tariff, effectively providing further disincentive to reduce fuel costs. The IFR accelerates the moral hazard of 100% fuel pass through costs.[20]

Because the IFR Mechanism worsens the moral hazard described above, the Commission should not approve it and should, instead, keep the current IFR cap at $200 million (or consider reducing it back to 15%, in line with Albert Lin's Direct Testimony[21]).

The same is true regarding Georgia Power's hedging program. While the Company stated in testimony that "[b]y enhancing the scope of the hedging program, the Company will be better positioned to mitigate exposure to price fluctuations and provide greater stability in fuel costs,"[22] most of its testimony explains that price fluctuations can never be prevented. By expanding the hedging program, the Company will pay more for this "insurance," which, according to Staff's analysis, has provided ratepayers zero financial benefits: "Q. DID THE CUSTOMERS

[18] Staff Direct at 4 ("Staff disagrees with the Company's proposed changes to the Interim Fuel Rider ("IFR"); and instead recommends the IFR remain unchanged at the $200 Million threshold. Staff further recommends that when the threshold is exceeded, the Company not only make an informational filing, but also be required to propose an adjustment to fuel rates to minimize cumulative impacts until a comprehensive fuel case can be filed and reviewed. However, Staff recommends any proposed IFR changes to fuel rates occur no more frequently than once every three months").
[19] Stipulation at 2, ¶5a.
[20] Kalin Direct at 30.
[21] Direct Testimony of Albert Lin, GIPL, SI at 25 (Apr. 9, 2026) [hereinafter "Lin Direct"].
[22] GPC Direct at 4.

BENEFIT FROM THE COMPANY'S HEDGING PROGRAM OVER THE HISTORIC PERIOD? A. No. The Company reported over $273 million dollars in losses during 2023-2025."[23] Accordingly, Sierra Club, SACE and NRDC support the Stipulation's paragraph denying the Company's hedging request.[24]

C. The Commission Should Open a Fuel Cost Recovery Modernization

In addition to that RTP-specific proceeding supported below, the Commission should open a Fuel Cost Recovery modernization docket to explore fuel-cost-sharing and fuel-risk-sharing by the utility rather than continue the current moral hazard policy of passing through 100% of fuel costs to ratepayers. This Fuel Cost Recovery modernization docket should address, among other factors, the proper amount of fuel cost and fuel risk sharing to be assigned to Georgia Power, transparency of key contract terms, and reliance on forecasts versus actual historic pricing.[25] This docket would explore mechanisms to fairly share the risk of fuel cost changes between Georgia Power and ratepayers, and analyze at what percentage Georgia Power is sufficiently incentivized to reasonably manage its fuel costs.

2. <u>The Commission Should Disallow Recovery of at Least $152 Million due to Georgia Power's Uneconomic Dispatch of Coal</u>

As an initial matter, the Company's pre-filed direct testimony explains that the "FCR-27 budget includes must-run requirements for Plant Bowen to address system constraints and ensure operational reliability."[26]. In practice, this means that, for Bowen specifically, 3,498.6 MW of nameplate capacity will be dispatched regardless of economics. This will be and has been the case even when cheaper options have been available to meet the Company's demand. Hence, by designating a coal unit as must-run, Georgia Power may be leaving cheaper resources on the

[23] Staff Direct at 66.
[24] Stipulation at 2, ¶7 ("The Company's request to expand the natural gas hedging program is denied. Effective upon the effective date of FCR-27 rates, Georgia Power's natural gas hedging program shall be modified from the parameters approved by the Commission in FCR-26 (Docket No. 44902) to permit the Company to hedge up to 20% of its budgeted natural gas fuel burn in any given month, with a maximum hedging window of 36 months").
[25] *See* Kalin Direct at 19.
[26] GPC Direct at 17.

table. This is especially concerning given that, as GIPL's expert Albert Lin testified, in many cases, coal is not even cheaper than gas.[27] Witness Goggin's analysis:

> indicates that the Company's coal units are routinely operating at a loss, reflecting that their marginal cost of producing electricity is greater than that of other resources that were available (...) Said another way, the Company ratepayers would have saved money if the Company replaced the coal generation with energy generated by another resource.[28]

Despite having little information supporting the Company's must-run designation of coal and its justification, Witness Goggin's analysis did not dispute that certain units were needed at certain times, and excluded those timeframes from the total proposed disallowance amount of $152 million:

> The Company did not provide adequate information about its commitment and dispatch model processes and results to assess the extent to which the must-run commitments of coal units were prudent. To be conservative, we have excluded uneconomic dispatch costs incurred during must-run designations from our analysis. As a result, the recommended disallowance is $152 million. If net costs incurred during must-run designations were included, the recommended total disallowance would increase[.][29]

In this sense, Witness Goggin's analysis was conservative because it "exclude[d] net ratepayer costs that were incurred during must-run designations, as the Company did not provide sufficient information to assess the prudency of those must-run designations."[30] It was also conservative because:

> time periods in which a coal unit was unprofitable, but shutting it down and restarting it would have resulted in higher net costs to ratepayers, were not counted in our analysis as they did not impose a net cost on ratepayers. [Witness Goggin] also incorporated the Company's reported coal unit operating constraints, including startup time, minimum uptime, and minimum downtime when designing this counterfactual.[31]

Witness Goggin also replied to each of the Company's allegations seeking to undermine his testimony:

---

[27] *See* Albert Lin's cross examination 7:08:00, https://youtu.be/LNMvQS7AkSc?t=25690.
[28] Goggin Direct at 4-5.
[29] *Id.* at 12.
[30] *Id.* at 6.
[31] *Id.* at 7.

- Georgia Power claimed that Bowen had a 7-day minimum downtime period. In stark contrast, PJM's default assumption is that coal units require an 8-hour minimum downtime. In any case, Witness Goggin's analysis used the startup time, startup cost, and minimum up time provided by the Company, which already ensured the analysis only identified periods when it was economic to shut down the coal units for long periods of time. Even assuming the Company's coal units actually have a 7-day minimum down time, that reduces the recommended disallowance by less than $1 million as more than 99% of periods when his analysis decommitted the coal units were longer than 7 days.[32]
- Georgia Power expressed concern with the using day-ahead lambda. Yet "[i]f the coal unit's cost is higher than system lambda, this indicates that the lower-cost generator setting the system-wide lambda, and in many cases other resources like imports, could have more economically provided that generation than the coal unit."[33]. In response to Georgia Power's claims, Witness Goggin explained that day-ahead lambda is an output of the company's dispatch model, and reflects the marginal cost of the marginal resource in the day-ahead timeframe when Georgia Power had to decide which coal units to commit, which is the relevant metric for assessing if commitment decisions were prudent.[34] Replacing a coal unit with an alternative would not have a significant impact on lambda because all of the uneconomic commitment periods identified in his analysis occurred when lambda is low, which reflects that supply is abundant relevant to demand, so you are on the flat left side of the generation supply curve, where marginal production

[32] Under more reasonable assumptions for minimum downtime, there is no impact on Witness Goggin's results. At 8 hours of minimum downtime, his analysis does not change as no shutdown periods were 8 hours or shorter. At 24 hours minimum downtime, two shutdowns are impacted, reducing the uneconomic dispatch estimate by about $10,500, which is 0.007% of the total uneconomic dispatch estimate. Witness Goggin also tested 48 hours minimum downtime, which impacted three shutdowns and reduced the uneconomic dispatch estimate by $37,000 or a 0.02% change.

[33] Goggin Direct at 8.

[34] *See generally* Witness Goggin's cross examination (https://youtu.be/LNMvQS7AkSc). *See also* Goggin Direct at 8 ("Because coal plants take a long time to start up and have limited flexibility, our analysis exclusively focused on the day-ahead forecast for system lambda. This metric accurately reflects the supply and demand balance and generator economics in the day-ahead timeframe when the Company decided which power plants to commit to operate so that long startup time coal units could be online by the next day. This makes our analysis conservative, as it does not penalize the Company when there were unexpected drops in electricity demand or increases in supply after the day-ahead timeframe when it committed the coal units. Said another way, this ensures the analysis is not 'Monday morning quarterbacking' with the advantage of perfect hindsight, and instead is only judging the Company's commitment decisions based on the information that was available to the Company at the time it made those decisions").

costs do not change significantly with changes in demand.[35] Operating reserve needs are a trivially small component of total commitment and dispatch decisions; in fact, most production cost models ignore operating reserves because they do not have a significant impact on commitment results or marginal production costs. That is particularly true when you are on the flat left side of the supply curve and marginal production costs do not change significantly with changes in demand.

- Georgia Power claimed that it uses 8-day ahead planning. However, as established in the hearing, the relevant timeframe is day-ahead as that aligns with the cold start up time for Bowen and Scherer.[36] The Company can and does change planned commitments during the course of the 8-day look ahead window in response to changes in load forecasts and the supply outlook. For a coal unit, the timeframe that matters is day-ahead as that is when the decision to start up has to be made.
- Georgia Power argued that the main difference between the Company's model and Witness Goggin's is that the Company's model follows transmission constraints and local reliability. As explained above, Witness Goggin conservatively assumed all must-run coal unit commitments, which the company indicated were all for transmission constraints and local reliability needs, were prudent. As a result, none of the $152 million in recommended disallowance were due to transmission constraints; those transmission must-run commitments are tallied in an additional $X million that was not included in our recommended disallowance.[37]

While not an IRP, the dramatic uneconomic dispatch costs of coal, particularly Plant Bowen, that were discovered in this proceeding should lead the Commission to "recognize that transitioning to a fleet with more flexible resources, like battery storage, will reduce the need to unprofitably operate inflexible coal resources."[38]. The Company's "persistent and significant overestimate of need contributes to the overcommitment of coal units, which results in uneconomic dispatch of those coal units to the detriment of ratepayers. The Commission should

[35] *See generally* Witness Goggin's cross examination (https://youtu.be/LNMvQS7AkSc).
[36] For particular timeframes, see STF-PIA 2-6, Trade Secret Attach.
[37] The "X" in this sentence refers to a trade secret amount that can be consulted in the Trade Secret version of Witness Goggin's testimony.
[38] Goggin Direct at 7.

also recognize that transitioning to a fleet with more flexible resources that can quickly start up and respond to changes in supply and demand, like battery storage, will eliminate costs caused by day ahead forecast errors."[39] In this proceeding, "the Commission can disallow [$152 million] in costs that were imprudently incurred from the excessive operation of" its coal plants.[40]

Alternatively, at the very least, the Commission should require Georgia Power to (1) cease entering into coal-supply or transportation contracts that include minimum-delivery obligations with liquidated-damages or similar penalty provisions, (2) restructure any future agreements to eliminate the fixed-cost distortions that drive uneconomic coal dispatch, and (3) remove or adjust the biases causing certain over-forecast for day-ahead load and day-ahead solar under-forecast, which cause conventional generation to be overcommitted.

3. Georgia Power's Recurring Practice of Buying Expensive Coal

Staff conducted an investigation of the Company's coal procurement activities.[41] That analysis shows that the Company's repetitive practice has been to purchase more expensive coal when other cheaper options were available.[42] While Staff did not ask the Commission to disallow any particular amount attached to the Company's coal purchasing activities, it did characterize this practice as problematic, and something that the Commission should look into.[43] Georgia Power's rebuttal panel admitted publicly that this amount was roughly 9 or 10%. The Company's use of coal is expected to increase over the next three years[44], and as the Company plans to burn more coal over the next few years, the risks Staff lays out in testimony will increase and have a bigger impact on the Company's and ratepayers' bottom line.

It is not Georgia Power's business to ensure that coal mines stay in business. While the Company may prefer to maintain relationships with multiple suppliers to hedge against potential supply disruptions, that preference cannot justify constantly paying above-market prices for coal.

---

[39] *Id.* at 14-15.
[40] *Id.* at 13-14.
[41] Staff Direct at 27-33.
[42] *See e.g. id.* at 30.
[43] *See id.* at 31 ("While Staff acknowledges that the Company would like to maintain diversity with its suppliers and regions from which it acquires coal, Staff is concerned that the added cost of acquiring coal from the X mine is not inconsequential. A rough estimate of the X coal acquisition as a percentage of total Bowen coal expected to be purchased in 2027 is that X represents close to X% of the total coal acquisition in 2027….) ("X" in this sentence refers to trade secret information).
[44] Staff Direct at 52, tbl. 18.

For this reason, while Sierra Club, SACE and NRDC agree with the intention of paragraph 9 of the proposed Stipulation ("The Company will limit higher than market price coal purchases to 15% of total purchases"), the cap amount should be lowered to 0-5%.

4. <u>RTP proceeding</u>

Sierra Club, SACE and NRDC support the Stipulation's paragraph 6 creating a separate proceeding in which "[t]he Commission shall further review the methodology by which the Company credits RTP revenue to the FCR revenues and the allocations that the Company is making under such methodology in this Docket." As Staff testified, there are "discrepancies in the treatment of RTP revenue used to offset FT costs recovered in fuel rates" as well as in take-or-pay contracts.[45] Consequently, Staff recommended that the Commission "open an investigation docket to consider if the RTP fuel credit methodology and the Company's application of the methodology going forward is sufficient to protect non-RTP customers from cost-shifts associated with future load growth."[46] While it has been the Company's recurring position that data centers will pay for their fair share of the costs of bringing more generation online to meet their needs, "[t]he Company's FCR-27 application appears to require that a significant amount of new data centers be built in order to achieve the claimed benefits or general ratepayer protections,"[47], and:

> the Company has not clearly stated the extent to which additional fuel costs will be incurred regardless of whether large loads are realized (in other words, whether large data centers are actually built and begin operating), or if some fuel costs will be incurred by the company and cannot be curtailed or avoided should the large load growth not be realized, or fall short of the forecasted load growth.[48]

With FCR-27, the Company would have committed significant sunk costs into serving these large loads, including hedging premiums and firm transportation costs incurred years in advance of new loads coming online: "All of the Company's ratepayers will face these increased hedging premiums if any project large load is not realized within the FCR-27 period, or at all."[49]

[45] *Id.* at 5.
[46] *Id.*
[47] Kalin Direct at 11.
[48] *Id.* at 13.
[49] *Id.*

[50] Accordingly, the proposed Stipulation's paragraph establishing a dedicated proceeding to examine RTP is essential to ensuring that non-RTP customers are not shouldering fuel-related risks and costs driven by data center growth.

CONCLUSION

Georgia Power has asked this Commission to continue a framework in which the Company bears none of the consequences of its own fuel-related decisions while ratepayers bear all of them. The record in this proceeding demonstrates why that framework harms ratepayers. The Company's uneconomic coal dispatch, its persistent over-reliance on gas and its repeated procurement of above-market coal, demonstrate that when fuel costs are 100% passed through to customers, the utility has no meaningful incentive to minimize them. O.C.G.A. § 46-2-26 does not require the Commission to accept that result.

For these reasons, Sierra Club, SACE, and NRDC respectfully request that the Commission (1) disallow $152 million in imprudently incurred coal-dispatch costs,[51] (2) reject the Company's proposed expansion of the IFR mechanism and maintain the current cap (or, alternatively, adopt paragraph 5(c) of the proposed Stipulation), (3) adopt paragraph 7 of the Stipulation denying the Company's request to expand its hedging program, and (4) open a Fuel Cost Recovery modernization docket to evaluate appropriate fuel- and fuel-risk-sharing reforms, in addition to adopting paragraph 6 of the Stipulation.

Respectfully submitted this 14th day of May 2026.



Isabella Ariza
50 F Street NW, 8th Floor
Washington, D.C. 20001
(857) 999 6267
isabella.ariza@sierraclub.org

[50] But the Stipulation adequately limits hedging, see pg. 6 above.

[51] Alternatively, at the very least, the Commission should require Georgia Power to (1) cease entering into coal-supply or transportation contracts that include minimum-delivery obligations with liquidated-damages or similar penalty provisions, (2) restructure any future agreements to eliminate the fixed-cost distortions that drive uneconomic coal dispatch, and (3) remove or adjust the biases causing certain over-forecast for day-ahead load and day-ahead solar under-forecast, which cause conventional generation to be overcommitted.

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:		
GEORGIA POWER COMPANY'S FUEL COST RECOVERY (FCR-27)	)	**DOCKET NO. 56765**

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of Sierra Club, SACE, and NRDC's Post-Hearing Brief has been furnished by electronic mail on this 14th day of May 2026, to the following:

Sallie Tanner
Georgia Public Service Comm.
244 Washington Street, SW Atlanta,
GA 30334
stanner@psc.state.ga.us

Robert Trokey
Justin Pawluk
Chris Collado
Tom Newsome
Jamie Barber
Georgia Public Service Comm.
244 Washington Street, SW Atlanta,
GA 30334 rtrokey@psc.ga.gov
jpawluk@psc.ga.gov
ccollado@psc.ga.gov
tnewsome@psc.ga.gov
jamieb@psc.ga.gov

Jeremiah Haswell
Kyle Leach
Georgia Power Company
241 Ralph McGill Boulevard, NE
Atlanta, GA 30308-3374
jhaswell@southernco.com
kleach@southernco.com

Jennifer Whitfield
Amitav Kamani
Bob Sherrier
Alyssa Krantz
Southern Environmental Law Center
Ten 10th Street, NW, Suite 1050
Atlanta, GA 30309
jwhitfield@selc.org
akamani@selc.org
bsherrier@selc.org
akrantz@selc.org

Brandon F. Marzo
Steven J. Hewitson
Allison W. Pryor
Troutman Pepper Hamilton Sanders
LLP 600 Peachtree Street NE, S. 3000
Atlanta, GA 30308-2216
brandon.marzo@troutmansanders.com
steven.hewitson@troutman.com
allison.pryor@troutman.com

Robert B. Baker
Robert B. Baker, PC
2480 Briarcliff Road, NE, Suite 6
Atlanta, Georgia 30329-3008
706-207-5001
bobby@robertbbaker.com

Charles B. Jones, III
Jim Kelleher
Georgia Association of Manufacturers
75 Fifth Street, NW
Suite 3412
Atlanta, GA 30308
cjones@gamfg.org
jkelleher@gamfg.org

Jeffry C. Pollock
J. Pollock Incorporated
14323 South Outer 40 Road, S. 206N
Town and Country, Missouri 63017
jcp@pollockinc.com

Maggie Shober
Southern Alliance for Clean Energy
PO Box 1842
Knoxville, TN 37901
(865) 235-1448
maggie@cleanenergy.org

Jim Clarkson
Resource Supply Management
135 Emerald Lake Rd
Columbia, SC 29209
803-312-3500
jclarkson@rsmenergy.com

Patrick King II
Natural Resources Defense Council
1152 15th St. NW #300
Washington, D.C. 20005
(225) 241-2140
pkingii@nrdc.org

/s/ Caden Koontz
Caden Koontz
Sierra Club
50 F St. NW, Eighth Floor
Washington, DC 20001
(202) 650-6075
caden.koontz@sierraclub.org