STATE OF GEORGIA

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:

Georgia Power Company's 2023	**)**	
Integrated Resource Plan Update	**)**	
And Application for Certification	**)**	
Of Plant Yates Units 8-10	**)**	
	)	**Docket No. 55378**
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Direct Testimony of
Peter Hubbard
Georgia Center for Energy Solutions

February 15, 2024

Direct Testimony of Peter Hubbard

on the Georgia Power Company 2023 Integrated Resource Plan Update

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

A. My name is Peter Hubbard. I am a Clean Energy Advocate with the Georgia Center for Energy Solutions (GCES). My business address is 55 Leslie Street SE, Atlanta, Georgia 30317.

Q. PLEASE DESCRIBE YOUR ORGANIZATION.

A. GCES seeks to develop an economic and regulatory framework to transition Georgia's electric, transportation, buildings, and agriculture sectors to a 100% clean energy (zero-carbon) future in an equitable, reliable, resilient, sustainable, rapid, and economically efficient manner and in furtherance of the public benefit.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. My professional experience is in renewable project development and energy management consulting focused on electric utility Integrated Resource Plan (IRP), organized power markets in North America, global gas market analysis, commodity price projections, stochastic risk analysis, scenario development, capacity expansion modeling, and production cost modeling. I have 15 years of professional experience in the energy sector.

Q. MR. HUBBARD, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION?

A. I have previously filed direct testimony and given an oral summary of my direct testimony before the Georgia Public Service Commission ("Commission") related to the Georgia Power Company (GPC or the Company) 2019 Integrated Resource Plan in Docket #42310 and again in the GPC 2022 IRP and Application for Certification of 2,356 MW of gas-fired Power Purchase Agreements (Docket #44160).

Q. **ON WHOSE BEHALF ARE YOU TESTIFYING?**

A. I am testifying on behalf of the Georgia Center for Energy Solutions.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of this direct testimony is to demonstrate how GPC is using flawed analysis in its application before the Commission to certify the Yates CTs, resulting in an unjust cost shift onto residential ratepayers in particular and an imprudent plan to build new gas-fired generating assets. These new gas plants are at risk of becoming stranded assets whose costs will be further shifted onto residential ratepayers as regulatory assets. I will provide examples of GPC acting in ways that result in fewer choices in the open market. And I will provide pragmatic solutions to help GPC meet the acute near-term capacity shortage due to load growth without building new gas-fired units at Plant Yates.

Q. WHAT CAN WE LEARN FROM GEORGIA POWER COMPANY EXPANSION PLANS IN THIS 2023 IRP UPDATE, PARTICULARLY THOSE CASES WITH UNPROVEN CARBON CAPTURE?

A. In Document Filing #216658, Supplemental Filing Errata dated 12-7-2023, GPC provides only six (6) capacity expansion plans out of the 14 portfolios evaluated in the 2022 IRP. Three of these capacity expansion plans (MG0, LG0, HG0) include a $0 CO2 price while varying the wholesale price of gas, which significantly favors selection of gas-fired resources by shifting costs onto GPC customers. As a result, these three portfolios heavily select 8 to 11 GWs of new gas-fired capacity by 2036. These same three portfolios include 1 to 2 GWs of brand new nuclear beginning in 2035, which is impossible for several reasons.[1] In

[1] NuScale was the top contender for a First-Of-A-Kind Small Modular Reactor to achieve commercial status until it withdrew its project in November 2023. NuScale had planned to develop a six-reactor 462 MW project in Utah with a COD in 2030, but partners began to pull out of the project as estimated costs rose from $58/MWh to $89/MWh. Compare this cost to the GA PSC Commission estimate for Vogtle Units

the next two capacity expansion plans (MG20, MG50), GPC clings to its gas-fired capacity by conjuring up Carbon Capture and Sequestration (CCS). GPC only has to look to their affiliate in Mississippi Power Company and the ruinous disaster that was the Kemper Project to understand that CCS is not a commercial technology with too many failures to count. But we could ask Southern Company, who manages and operates the National Carbon Capture Center south of Birmingham, Alabama. Their website notes they've spent 150,000 testing hours with no commercial CCS project, but there is a DOE funded report[2] that states, "*Our models indicate that our technology can meet the DOE cost targets for carbon capture* ***by 2035****. The technology is flexible to multiple applications including post-combustion carbon capture from industrial sources or direct air capture."* GPC is proposing 4 to 8 GWs of gas-fired combined cycle capacity w/ CCS in 2034. In its response to STF-PIA-10-8 question, "Has the Company evaluated the cost of installing carbon sequestration and storage, hydrogen conversion, or gas dual firing or conversion at any of its existing fossil plants (coal or gas-fired)?" GPC responds, "*Georgia Power has not evaluated the cost of installing carbon sequestration and storage, hydrogen conversion, or gas fuel firing or conversion at any of the Company's existing fossil plants (coal or gas-fired). However, at the direction of counsel, in 2021, Southern Company Services conducted a system level pre-screening analysis related to the installation of carbon sequestration and storage at fossil plants across the system. This is a confidential technical and legal analysis.*" Be that as it may, CCS is not commercial. Then in its response to STF-PIA-10-9 question, "*Has the Company evaluated the cost of installing carbon sequestration and storage, hydrogen conversion, or gas dual firing or conversion at any of its newly proposed fossil plants?"* GPC responds, "*The Company has proposed to construct Plant Yates*

3&4 at $150/MWh. In addition, a COD of 2035 is unrealistic given the 15-year experience at Plant Vogtle. https://www.eenews.net/articles/the-kemper-project-just-collapsed-what-it-signifies-for-ccs/

[2] Precision Combustion, Inc., "High-Efficiency Post Combustion Carbon Capture System National Carbon Capture Center Contractor Report," DOE Award Number: DE-SC0017221, issued 2023

Units 8-10 as a new fossil generation resource and submitted the air permit application to the Georgia Environmental Protection Division on December 8, 2023. As a part of the control technology evaluation required in the air permit application, the Company evaluated the feasibility of installing carbon capture and sequestration ("CCS") or low-greenhouse gas ("GHG") hydrogen co-firing for Plant Yates Units 8-10. Although these technologies are not demonstrated nor technically feasible for implementation on simple cycle combustion turbines, the Company nonetheless included an assessment of possible costs using generic and publicly available information. In this evaluation, there were still certain costs that could not be quantified, and no site-specific engineering was completed. ***The control technology evaluation concluded that even the partial costs for CCS or low-GHG hydrogen co-firing are unreasonable for Plant Yates Units 8-10.***" This is GPC itself saying that the Yates CTs will never see CCS technology bolted on, not now, not ever. The Yates CTs are guaranteed to become stranded assets in a rapidly decarbonizing world.

Q. IS GEORGIA POWER COMPANY PROVIDING STRAIGHTFORWARD ANALYSIS OF ITS LOAD GROWTH PROJECTIONS?

A. In STF-DEA-1-5, GPC states that, "G*eorgia Power selected a P95 load value in response to the unprecedented pace of economic development in the state of Georgia and because the Company has seen more increases in large projects interested in the state over the last several months than decreases. The P95 value establishes an upper limit for potential large load outcomes, offering a heightened level of load realization that is expected to benefit all customers and additional capacity resources to accommodate potential load increases in the ongoing economic development pipeline. Considering the uncertainty surrounding future growth, the Company opted for the P95 load value to ensure sufficient capacity to meet the anticipated loads and continue to support economic development in*

Georgia and to benefit all customers." This allows GPC to exaggerate the load growth, helping to justify the capital cost of building new gas-fired generation.

Q. HOW DOES GEORGIA POWER CO. CONSISTENTLY UNDERESTIMATE THE COST OF NATURAL GAS FUEL?

A. GPC has a long history of consistently underpricing fuel costs, favoring gas capacity and leaving ratepayers exposed to volatile commodity markets. Back in 2007 GPC said, "*Since the approval of the 2004 IRP, fuel costs are significantly higher. Fuel commodity prices have increased from previous estimates.*"[3] In 2010, GPC said, "*Since the approval of the 2007 IRP, fuel costs have experienced significant volatility. Fuel commodity prices increased to record prices in the summer of 2008 and subsequently declined significantly in 2009. This price volatility highlights the need for fuel diversity to protect customers from fuel price fluctuation.*"[4] In 2013, GPC said, "*The IRP planning process overseen by the Commission has created a versatile fleet that can respond effectively to swings in gas and coal prices, with new nuclear providing low cost energy and greater fuel cost stability than fossil fuels.*"[5] GPC expressed grave concern about the cost of the EPA MATS rule in its interim 2011 IRP Update, but in 2013 was able to eliminate significant uncertainty and select a MATS compliance plan that, "*equates to a savings of several hundred million dollars for customers.*"[6] In its 2016 IRP, GPC moved from MATS to the newest grave concern over the EPA's Clean Power Plan that result in nearly $1.4 billion in higher costs and to compensate GPC for retiring its fossil-fired units.[7] In 2016 with significant Vogtle

[3] Docket #24505, Georgia Power's 2007 Application for Approval of an Integrated Resource Plan, page 1-5

[4] Docket #31081, Georgia Power's 2010 Integrated Resource Plan Main Document, pages 1-7 and 1-8

[5] Docket #36498, Georgia Power's 2013 Application for Approval of an Integrated Resource Plan, page 1-10

[6] Docket #36498, Georgia Power's 2013 Application for Approval of an Integrated Resource Plan, page 1-4

[7] Georgia Power Company: "Using the EPA's assumptions, in 2016-2017 alone, the CPP would, for Georgia Power, result in $830 million in incremental costs related to increased production costs and an insufficient reserve margin, $70 million in additional transmission projects, $485 million to compensate for impacts to

construction delays and cost overruns, GPC continued, "*It is important that nuclear continue to be evaluated as a possible resource option for the future. With the reality of carbon regulation, the Company must continue to be proactive in its consideration of future nuclear as a viable baseload option.*" GPC sought $175 million to pursue even more nuclear power in Stewart County. GPC says, "*Energy efficiency and renewable resources cannot provide a reliable and economic supply of electricity to customers without other resources in place* [note: this is verifiably false]." GPC adds, "***Adding only natural gas-fired resources would result in an over-reliance on a fuel with a history of volatility and which is subject to potential future cost increases driven by regulation, changing market conditions and other factors.***"[8] By 2022, gas-fired generation was back in favor with 2,356 MWs of gas PPAs approved. Now, in 2024, GPC is seeking certification of the Yates CTs. GPC consistently underestimates the cost of fuel in its planning by selecting moderate fuel costs with no environmental compliance costs where external emissions and economic and public health costs remains outside of the analysis, leading to favorable treatment of gas-fired resources.

Q. HOW HAS GEORGIA POWER COMPANY MANIPULATED THE IRP PROCESS IN ITS FAVOR?

A. GPC has a long history of changing the rules of its IRP process to obtain the company's preferred portfolio, but not what is in the public interest. In 2007 GPC asked, "*that the requirement to conduct RFPs be waived in years where the IRP Mix Study identifies baseload nuclear or coal capacity as the most cost effective resource. The 2007 IRP Mix Study selected nuclear as the most cost effective resource in the 2015 and 2016 timeframe. Because the Company is still uncertain as to when next generation nuclear will be available* ***the Company has taken a***

the fuels program and the retirement of over 4,000 MW of fossil-fired units with a current value of over $3.7 billion." Docket #40161, page 1-5

[8] Docket #40161, Georgia Power's 2016 Application for Approval of an Integrated Resource Plan, page 6-77

conservative approach by listing the first new nuclear unit in 2016."[9] The Commission ordered GPC to issue an RFP for capacity and energy resources identified in its 2007 IRP (Docket #25036), which resulted in three PPAs for 1,800 MW of gas-fired facilities, most of which is still under contract today.

Q. HOW IS GEORGIA POWER COMPANY FAILING TO ACCOUNT FOR TAX CREDIT OPPORTUNITIES FROM THE INFLATION REDUCTION ACT?

A. In its response to STF-JKA-2-19-f, GPC states, "*Both the Company's economic analysis and Resource Mix Study assume BESS resources would utilize the ITC. Likewise, both evaluations assume solar resources would utilize the PTC. The economic analysis does not assume domestic content or energy community benefits at commercial operation for the proposed projects given the chosen locations and likely source of materials for construction. However, the BESS augmentations are expected to receive bonus credits for domestic content. The Resource Mix Study assumes either energy community or domestic content benefits will be available for generic renewable or BESS additions. Therefore, the Resource Mix Study assumes those Inflation Reduction Act ("IRA") benefits.*" The problem is that GPC is undercounting the IRA benefits, using only a 40% tax credit for generic renewables or BESS additions when 50% is expected for utility scale solar and storage projects. It is possible for distribution level solar and storage projects to achieve even higher percentages of a project's cost in ITC and other federal benefits provided by the IRA. Moreover, GPC is suppressing the development of new solar and storage resources by not committing to a retirement date of 2028 for its coal units, which would unlock the 10% Energy Community tax credit at critical sites like in and around Plant Bowen, where GPC stated they had critical transmission issues. Plant Bowen is facing significant new capital costs to meet the proposed 2023 ELG Rule, which is a risk GPC is not accounting

[9] Docket #24505, Georgia Power's 2007 Application for Approval of an Integrated Resource Plan, page 1-8

for appropriately. When GPC says, "*The Company remains optimistic about the potential of the IRA to reduce the cost of new renewables for customers,*" they mean they will slow-walk solar and storage deployment for as long as possible.

Q. COULD GPC IDENTIFY SHORT-TERM SOLUTIONS FROM AMONG THE RECENT RFI RESPONDENTS?

A. In STF-DEA-9-2, which notes that GPC stated, "T*here is not enough time for an RFP to be conducted, resources to be constructed following certification, and transmission projects to be identified and completed to allow delivery by the end of calendar years 2025, 2026 or 2027,*" we learn that more than 2,700 MW of resources responded to the RFI and are expected to be available by the end of 2027. The RFI included: Standalone BESS with grid charging capability; BESS with a Renewable Resource with grid charging capability; and gas-fired generation. However, GPC concluded from this RFI that there were no existing resources available for the need years addressed in this IRP. GPC is able to and should tap this pool of resources to address the acute short-term capacity shortage. I urge the Commission to require GPC to allow each of these RFI respondents, and all newcomers, to provide unsolicited proposals that will be assessed from an interconnection standpoint in accordance with FERC Order 2023.[10]

Q. HOW HAS GEORGIAPOWER COMPANY DEMONSTRATED ANTI-COMPETITIVE BEHAVIOR?

A. GPC has a long history of anti-competitive behavior. In particular, GPC intentionally makes it difficult to develop cheap, clean, firm new generation resources in Georgia by obscuring and changing the calculation of system Avoided Cost, which is the cost GPC avoids by not producing for itself an equivalent amount of energy and capacity. PURPA requires electric utilities to purchase the electric energy and capacity made available by these generators at

[10] https://www.ferc.gov/explainer-interconnection-final-rule

just and reasonable rates. However, independent power producers have had difficulty selling energy and capacity to GPC, whether as a PURPA qualifying facility or when trying to secure a Power Purchase Agreement. Last month, a major developer of renewable capacity and energy resources filed a petition before this Commission in Docket #4822 that states, "***At a time when Georgia Power acknowledges its urgent need for new generation capacity, [this developer] urges the Commission to remove unlawful barriers blocking the development of 420 MW of new, clean, affordable power generation that [this developer] stands ready to build and operate.***" This developer has significant solar and storage capacity it could bring online to help meet the acute short-term capacity shortage, but for GPC standing in the way. In the 2022 IRP and again in the 2023 IRP Update, the Incremental Capacity Equivalent (ICE) Factor showed utility scale solar with a 10% winter and 35% summer capacity value (rooftop solar is 5% and 25%, respectively). Solar has non-zero capacity value at all times, yet solar received a 0% capacity credit in the GPC capacity RFP.

When GPC initiated conversations in the marketplace seeking available capacity (see response to STF-JKA-2-19), GPC had, "*initial exploratory conversations in early August 2023 regarding Georgia Power's potential acquisition of additional ownership interests in an existing generation asset within the Southern Company footprint. Following initial discussions and through September 2023, the Company began its due diligence on the assets, scope, risks, and applicable regulatory requirements for the potential acquisition. Between early October 2023 and end of November 2023, the parties engaged in active negotiations regarding the terms and conditions for the proposed asset purchase agreement. However, on November 30, 2023, the parties agreed to suspend negotiations and not move forward with the transaction at this time. As stated in the direct testimony filed on December 4, 2023, the Company is no longer pursuing the potential acquisition of additional ownership interests in an existing generation asset within the Southern Company footprint.*" This was an opportunity that GPC

passed, likely based on faulty assumptions and possible anti-competitive practice, that could have helped to mitigate the acute near-term capacity shortage.

In its response to STF-PIA-9-11 "*What cost threshold would the proposed 200 MW of BESS co-located with 200 MW of new solar facility be held to? Would avoided cost be an appropriate threshold? If so, what avoided scenario (MGO, etc.)? If not, please explain why. Would bids from a recent or future renewable with BESS RFP be an appropriate threshold? If not, please explain why,"* GPC states, "*traditional avoided cost threshold is inappropriate for meeting an identified capacity need. The objective is to meet the identified need at the lowest incremental cost to customers given the capacity options available to the Company at the time. Bids from past or future RFPs do not represent capacity options that are currently available to meet the identified capacity need addressed in the 2023 IRP Update and would therefore be an inappropriate cost threshold as well.*" GPC was completely unsuccessful in its attempt to reach agreement with the bidders of 2023/2024 RFP, reportedly eliminating offers for 1,030 MW of renewable resources that did not pass the economic hurdle of artificially-low Avoided Cost parameter, which has since been relaxed into a best cost analysis in the latest RFP but it was too little, too late to salvage GPC's failing to procure more than half the solar and storage capacity they are required procure from the 2019 IRP, which could have helped to solve this acute near-term capacity shortage. GPC says twice in direct testimony[11] that "*time is of the essence*," but that only applies to building new gas capacity, not to renewable procurements required by the Commission.

Q. CAN YOU PROVIDE ADDITIONAL EXAMPLES OF GPC BEHAVIOR THAT YOU CONSIDER TO BE ANTI-COMPETITIVE.

[11] Document Filing #216591, Direct Testimony, page 24 line 14, page 31 line 9

A. The uncertainty and unfairness of GPC's calculation of Avoided Cost is a major impediment to the development of solar and storage resources in Georgia. By stripping out capacity revenues, by stripping out environmental compliance costs for coal ash into a separate rider, by stripping out nuclear construction costs into another separate rider, and so on, the leftover revenue ascribed to the cost avoided to produce a kWh of energy is not enough to make any project pencil without subsidies. Avoided Cost is difficult to finance in the best of circumstances, but near impossible with GPC's anticompetitive treatment of Avoided Cost.

In its response to STF-GS-1-8, GPC states, "*The Company is proposing a new Curtailable Load program, which will compensate customers for curtailing load during periods of extreme supply and demand conditions. The customer payment will be directly linked to the capacity value provided by the potential demand reduction.*" Why is GPC allowed to discriminate against generators who will receive zero capacity revenue in the Avoided Cost they use to price their PPA price offers, even though these generators will add physical generation capacity to the grid, whereas the newly proposed Curtailable Load program will provide capacity revenues for removing demand. The physical implications for transmission capacity behave similarly and should be treated similarly from a commercial standpoint. This is a way that GPC exhibits anticompetitive business practices.

Q. WHAT ARE THE REASONS THE MG0 CASE IS NOT AN APPROPRIATE REFERECE CASE ON WHICH TO BASE A PREFERRED PORTFOLIO?

A. The 2023 IRP Update cannot use the MG0 results because there is now a non-zero GHG emissions cost called the methane emissions charge beginning in 2024.[12] Any analysis based on a $0 GHG emissions cost is built on flawed, outdated assumptions that are not consistent with current regulatory reality. GPC has once

[12] https://crsreports.congress.gov/product/pdf/R/R47206

again chosen MG0 as its primary case, allowing GPC to ignore the 3 million tons per year of GHG emissions[13] that the Yates CTs will create, year after year with zero environmental compliance cost assigned, leading to the selection of the Yates CTs.

Q. PLEASE DESCRIBE THE RISK TO GPC CUSTOMERS FROM NEW GAS-FIRED GENERATION SUPPLY, INCLUDING STRANDED ASSET RISK, AND PROVIDE EXAMPLES.

A. GPC's plan to build new gas-fired generation capacity creates a broad range of risks of financial impairment for these assets in the near-term and long-term, likely shortening their useful life and putting the assets at risk to retire before project debt is fully amortized. These stranded assets costs are typically passed onto customers as regulatory assets, with little accountability for the utility who took the imprudent decision to build new gas capacity. The multiple financial risks to gas-fired resources are derivative of the regulatory risk, climate risk, fuel price volatility risk, and correlated fuel scarcity risk that all fossil gas resources face today, all of which are risks that are increasing over time. Moreover, these are risks that solar and storage projects do not face.

GPC says they are evaluating emissions abatement technologies for gas-fired CC and CT units such as Carbon Capture and Sequestration (CCS) and hydrogen in order to preserve the future optionality of new gas-fired generation in the face of increasing regulatory and economic pressure. However, it is likely that any retrofitting of gas-fired generating units with carbon emissions control technology like CCS or to co-fire hydrogen will be prohibitively costly to implement, leading to assets at risk of becoming financially stranded and forced to cease operations while still holding debt. This is because CCS is pre-commercial, risky, and a poor choice for abatement technology for the foreseeable future.

[13] See Document Filing #217280, Application for Certification of Yates 8-10, Table 3-3

Several new-build gas-fired generation projects that have been cancelled in favor of battery storage help to further exemplify the risk to TVA. Recently in Q4 2023, Competitive Power Ventures cancelled plans for its 657 MW gas-fired Keasley project in New Jersey[14], and Invenergy cancelled its 639 MW gas-fired Allegheny project in Pennsylvania[15], citing unfavorable economics compared to alternatives like battery storage. Global Energy Monitor reported[16] that in the first half of 2023, plans for 68 gas-fired power projects around the world were cancelled in favor of battery storage, due to unfavorable economics, uncertainty over revenues, fewer expected run hours, etc. These investment decisions align with analysis published by the Rocky Mountain Institute in December 2022 showing that more than 90% of proposed gas plants are outcompeted by cheaper renewable energy, thanks in large part to the IRA[17].

Specifically in this proceeding, GPC appears to use a 40-year book life for accounting purposes. The Yates CTs simply will not be able to recover the plant capital costs, let alone the $79.2 million in transmission improvements required by the Yates CTs[18], which will lead to a stranded asset costs that GPC will request be put into a regulatory asset and added to the rate base together with the original unamortized capital costs from the unpaid for Yates CTs and any additional environmental compliance costs. At a minimum, any gas-fired capacity must be 100% hydrogen-capable, which is currently commercially available from multiple OEMs, in order to preserve future optionality and avoid assets that are guaranteed

[14] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/competitive-power-ventures-pulls-plug-on-657-mw-gas-plant-in-new-jersey-77841585

[15] https://webcache.googleusercontent.com/search?q=cache:iZai_Cx0ETMJ:https://www.post-gazette.com/business/powersource/2023/11/14/invenergy-natural-gas-powerplant-allegheny-energy-center-cancelled/stories/202311130131&hl=en&gl=us

[16] https://www.reuters.com/business/energy/giant-batteries-drain-economics-gas-power-plants-2023-11-21/

[17] https://rmi.org/business-case-for-new-gas-is-shrinking/

[18] STF-DEA-4-1, Table 2

to become stranded. But H_2 is not a silver bullet[19] and represents significant moral hazard for GPC and its affiliates. The Southern Natural Gas Pipeline that delivers fuel to power plants in the Southeast is 50% owned by Southern Company. There is affiliate incentive and profit directly tied to the transport of gas to new-build gas-fired power plants. Southern Company spent $2.27 billion in 2015 on a gas pipeline, which now sells gas to GPC-owned gas-fired power plants. GPC-affiliate company Southern Company Services then provides specialized services, at cost, to Southern Company to market gas to affiliate-owned gas-fired power plants, costing $762 million in 2022 for their expertise in fuel supply services. These intimate commercial arrangements among affiliates and subsidiaries deserve greater regulatory scrutiny.

Q: PLEASE DESCRIBE THE RISK TO GPC FROM RISING FUEL COSTS AND PRICE VOLATILITY.

A: The US natural gas market is experiencing a long-term structural shift towards increased linkage to global markets due primarily to Liquefied Natural Gas (LNG) exports. The US became the top LNG exporting country last year[20] and as much as 30% of US natural gas production will be exported to markets primarily in Asia and Europe by 2030, doubling the percentage of current exports[21]. These LNG exports together with rising pipeline exports to Mexico and Canada will put upward pressure on the cost of natural gas that GPC must purchase for its gas-fired generation fleet. Increasing LNG and pipeline exports will more closely bind the US to the whiplash fluctuations of global markets and extreme weather events, adding to the inherent price volatility of commodities like natural gas. GPC has stated previously that the volatility of natural gas prices becomes a greater risk as gas-fired generation becomes a larger portion of its portfolio. This risk takes a

[19] https://www.canarymedia.com/articles/hydrogen/should-power-plants-burn-clean-hydrogen-to-make-electricity

[20] https://www.eia.gov/todayinenergy/detail.php?id=60582

[21] https://www.eia.gov/todayinenergy/detail.php?id=60944 and other sources

back seat to GPC's proposed plan to build new gas-fired capacity, which will certainly result in greater gas reliance and vulnerability to volatile fossil gas prices. Since GPC passes its fuel costs directly to customers, it is GPC's customers who are forced to bear this unlimited upside risk. This risk was borne out in 2022 when the annual average wholesale natural gas price in the United States was $6.45/MMBtu—or more than double the annual average of the prior 12 years—and GPC fuel costs skyrocketed as a direct result. Moreover, passing fuel costs onto customers invites moral hazard, which is discussed at length by the Southern Alliance for Clean Energy's expert witness Ron Binz before the South Carolina Public Service Commission, "*From the utility's perspective, operating a natural gas plant is not risky because there is no way the utility will collect less than its reasonable and prudently incurred cost for fuel, no matter how much the price changes.*"[22]

Q: IS GEORGIA POWER COMPANY PRUDENTLY ACCOUNTING FOR THE MANY RISKS THAT COME WITH INCREASED GAS-FIRED CAPACITY?

A: GPC is not accounting for the risk of more gas-fired capacity. Currently GPC relies heavily on thermal power plants; adding more gas capacity concentrates and increases the risk. During extreme weather events, which are becoming more common, thermal power plants can see their summer net dependable capacity reduced by 7% or more during period of high summer heat. Thermal plants may experience frozen equipment, involuntary interruptions to natural gas transport, and other winter-related causes for failure to dispatch reliably. Natural gas fuel supply issues are implicated in each of the last five major North American load shed events 2011-2022.

[22] https://cleanenergy.org/wp-content/uploads/South-Carolina-Fuel-Cost-Proceeding-Testimony-for-SACE-Upstate-Forever-SC-Coastal-Conservation-League.pdf

Q. DID GEORGIA POWER COMPANY FOLLOW ANY OF THE RECOMMENDATIONS IN YOUR DIRECT TESTIMONY IN THE 2019 IRP AND 2022 IRP?

A. In my 2019 direct testimony I made several recommendations: triple solar procurements to 3,000 MW; publish a distribution hosting capacity map; accurately model solar and storage as a dispatchable resource; and commit to a clearly articulated roadmap for 100 percent zero carbon system by 2050. The Commission stipulated in 2019 to more than double the GPC-proposed solar capacity. However, GPC only minimally complied with this requirement by issuing its second utility-scale solar RFP 10 days before the 2022 IRP was filed.[23] It went on to fail entirely and zero MWs of solar and storage were procured, to the best of my knowledge. This demonstrates an inability to execute on required obligations in a timely manner and a lack of respect for the Commission's stipulation. In my 2022 direct testimony, I pointed out the many ways in which GPC was steering the outcome of its IRP analysis toward its preferred outcome, providing credible analysis both from me and other experts. I demonstrated with GPC-provided analysis that they were increasing risk by decreasing fuel diversity with 2,356 MW new gas PPAs lasting up to 15 years. GPC failed to address any of the concerns raised and dismissed the direct testimony stating falsely that I did not bring any analysis. In this 2023 IRP Update and in its procurements, GPC continues to unjustly undervalue solar and storage and suppress wholesale market offerings with failed RFPs. GPC has yet to provide a credible plan to reach the 2050 Net Zero Carbon target set by Southern Company, despite GPC modelling out to 2056. GPC is now proposing to build new gas-fired power plants at high risk of cost shift onto GPC residential customers in particular and with no commercial prospects for carbon capture and sequestration.

[23] https://gpcrenew23.accionpower.com/_gpcrenew_2101/calendar.asp

Q. PLEASE PROVIDE A LIST OF PRAGMATIC SOLUTIONS TO THE ACUTE SHORT-TERM CAPACITY SHORTAGE THAT GPC SAYS IS URGENT.

Commissioner Echols said he felt the 2023 IRP update has been rushed and that GPC has not looked at all options to address the acute short-term capacity shortage caused by load growth, and I agree. He said we need creative solutions to meet the extraordinary energy and capacity needs requested by GPC in this 2023 IRP Update. Several options have been suggested, such as exploring Jacksonville Electric Authority's percentage ownership of Vogtle Units 3&4 as noted by SACE. GPC appears to be exploring solar plus storage microgrids with key federal partners in Georgia, which should be expanded to all customers with just and reasonable DER-enabling tariffs. GPC should explore energy and capacity wheeled from MISO into the SOCO tight pool as well as grid enhancing technologies. GPC should target BESS and hybrid projects in the SOCO interconnection queue that have already completed their interconnection studies and can be brought online relatively soon, assigning those projects their correct value when clearly GPC's Avoided Cost calculation is failing to adapt to market conditions. GPC should allow solar and storage projects to be evaluated correctly in the capacity expansion plan, whereas currently they are being modeled in Aurora incorrectly by GPC.

GPC does a disservice to this Commission and to ratepayers by omitting key information from this 2023 IRP Update. For example, this 2023 IRP Update does not review the benefits of residential rooftop customers and their contribution to capacity requirements and system reliability. This 2023 IRP Update omits the fact that there are over 40,800 MWs of solar photovoltaic, standalone storage, and hybrid solar+storage projects currently in the Southern Company Interconnection Queue, and that a substantial percentage of this dispatchable renewable capacity could be brought online in Georgia more quickly if GPC found a need to move

quickly. This 2023 IRP Update fails to acknowledge the tremendous benefit and cost savings to ratepayers that would come from sharing capacity resources with neighboring Balancing Authorities, whether bilaterally or through an organized wholesale capacity market.

Nevertheless, there are many solutions to the acute short-term capacity shortage caused by load growth. These solutions include, but are not limited to, the following **Solutions:**

There are 420 MW AC of solar that are ready to be built by one developer as of last month, but this capacity and energy cannot advance due to "unlawful barriers blocking development" imposed by Georgia Power Company (see Docket #4822). A policy of enabling DERs will lessen the cost and burden of rapid load growth in Georgia by allowing GPC's customers to invest their own money in local, distributed generation that reduces system requirements for both capacity and energy. There is now a large body of evidence to support the safe and reliable operation of bulk electric systems with a large penetration of renewables, including at the distribution level as in California. Other utility IRPs like the TVA IRP that shows Rapid DER Adoption is the least cost and best performing portfolio across five strategies in terms of Present Value of Revenue Requirements (PVRR), lowest total resource cost, least risk-benefit ratio, least risk exposure, lowest CO2 emissions, lowest CO2 intensity, lowest water consumption, lowest waste, and lowest land use, with a favorable flexibility turn down factor and with positive contributions to local employment. Should GPC engineers or management have any questions about managing the increase of intermittent renewables, they can be addressed in collaboration with the US Department of Energy and its national laboratories who offer technical assistance and operational experience.

In response to STF-PIA-3-5, GPC acknowledges that the Thermostat DR program shows a positive Total Resource Cost based on kW demand savings, and this despite lower Avoided Costs that hurt DSM measures. GPC is artificially limiting this program to 50,000 customers or well under 2% of residential customers, when it could expand the program to 2.7 million residential customers. This is a missed opportunity and an example of a concrete action this Commission can authorize to address the acute near-term capacity shortage.

In its response to STF-JKA-6-5, GPC states, "*Yes, the Company could consider an agreement outside of a RFP process for the potential new or planned projects.*" The Commission should require GPC to entertain unsolicited proposals received outside of announced RFPs and RFIs, which would be subject the same rigorous scrutiny for interconnection and other requirements without being burdened by GPC's onerous and time-intensive RFP and RFI solicitation process.
In Document Filing #216375 in Docket #44160, GPC gives its 2023 Q3 figures for Community Solar, which look pitifully small if accurate. GPC reports 0.04% of its residential customers are participating in the Community Solar offering. Clearly, this failure is on GPC's program design, whereas by contrast we have multiple examples of successful Community Solar programs flourishing across the United States.

The Intercompany Interchange Contract (IIC) provides for coordinated planning between the Operating Companies and for the sharing of surpluses and deficits of capacity. GPC could rely on the reserve sharing provision of the IIC, utilizing its affiliates' capacity surplus in Winter of 2026 to eliminate the GPC capacity deficit. See Hearing Request 1-3 for more context. Beginning in Winter of 2027, GPC notes that its need with planning reserve sharing would be slightly less due to another affiliate having a small amount of capacity surplus for Winter of 2027 through Winter of 2040. This capacity is available to Georgia Power customers

through reserve sharing and could, with Commission authorization, be used as a long-term capacity resource to serve the acute near-term capacity shortage.

Grid-Enhancing Technologies are technologies that are commercially available today, are low cost, and increase power grid transmission capacity by 30% or more to directly enable the existing grid to accommodate more renewable energy projects. Examples include Ambient Adjusted Rating devices that measure the power lines temperature, current, and angle in real-time. It allows utilities to implement hourly ratings that change based on the projected ambient temperature every hour instead of just summer and winter ratings and comply with FERC Order 881 as required by 2025. While this docket is focused on supply side resources with a passing glance toward demand side management, there is a direct impact on the cost of the Transmission Planning Study (Docket #25981). In its response to STF-GS-1-7 "*Has the Company evaluated whether the transmission upgrades identified in the Transmission Screening Analysis could be reduced, deferred, or eliminated with the deployment of grid-enhancing technologies including dynamic line ratings, topology optimization, power flow control devices, and similar solutions?*" GPC has not yet filed an update to its transmission planning study in Docket #44160 as of the intervenor testimony filing deadline, but they did respond, "*Due to the timing of the transmission constraints, the most appropriate projects were developed.*" Note that the PIA staff and intervenors asked if grid-enhancing technologies had been considered in the last IRP, and GPC demurred then as well as now. When asked if GPC is considering grid-enhancing technologies, the answer was no, they are considering reconductoring, redispatch, and rebuild but not dynamic line ratings and other grid-enhancing technologies. GPC will not pursue this low cost, commercially available suite of technology solutions known as grid-enhancing technologies that can help to solve the near-term capacity and energy shortfall unless the Commission requires it in this proceeding.

GPC did not discuss in its 2023 IRP Update main document or direct testimony that Plant Franklin is an existing resource that has 712+ MW of winter capacity resources in the short-term capacity need years, which did not participate in the GPC 2022-2028 Capacity RFP and which is owned by GPC's affiliate Alabama Power Company. [24] This existing gas resource was not considered, leading in part to the selection of new gas builds at Plant Yates. Any claim that PPAs are less reliable than GPC-owned assets, which limits PPAs to 30% of load, is much less of a concern than meeting load growth with available assets. Also, many PPAs are with GPC affiliates, raising concerns more about reliability with GPC affiliates and less about the contract structure of a PPA that can be rewritten to fully mitigate any perceived risk.

A program like Hawaii Electric Company (HECO) and their highly successful Battery Bonus program should be the model in Georgia. As noted, Battery Bonus is simple: the utility pays a cash incentive and provides bill credits for customers to add energy storage (a battery) to a new or existing rooftop solar system. All customers receive an $850/kW payment for the battery in exchange for a10-year commitment of capacity that is discharged from the battery for 2 hours during the evening peak. The popular Battery Bonus incentive in Hawaii quickly reached the cap of 3% of total firm capacity, demonstrating a rapid and proven solution to the acute near-term capacity shortage.

In its response to STF-DEA-4-9 GPC states that, "*No, the Company did not evaluate the potential of localized battery storage solutions to mitigate peak loads in the transmission screens filed in the 2023 IRP Update on October 27, 2023.*" GPC must consider localized utility-scale BESS specifically and DERs in general to mitigate transmission screens in the 2023 IRP Update. GPC must look at other hybrid solar and storage configurations including AC-coupled BESS that charge

[24] See DR STF-PIA-6-14-attachment

from the grid, rather than the BESS that GPC says will only charge from solar and not from the grid.

GPC can capture an additional 10% investment tax credit by retiring coal plants and siting new solar and storage facilities in the resulting Energy Communities. By keeping these coal plants running when they are currently uneconomic ***and*** not retiring them, they are putting significant upward pressure on electricity rates.

The US Department of Defense (DOD) is an important ***existing*** customer of GPC and is very supportive of hydrogen gas; they may be willing to pay the premium in order to meet their 2030 decarbonization goals. GPC must listen to its existing customers and work toward meeting their needs, or they will see their customers go to the market as the GSA and DOD are doing to procure 100% clean energy by 2030 for all federal facilities in the wholesale PJM market covering 13 states.[25]

The Commission can exercise its authority and obligation under O.C.G.A. § 46-3A-2 to determine that the GPC 2023 IRP Update fails to demonstrate the economic, environmental, and other benefits to the state and to customers of the utilities associated with the pooling of power, facilities that operate on alternative sources of energy, and energy efficiency; and ordering an independent, objective third-party consulting firm to prepare a new IRP that follows the law.

Q. GIVE AN EXAMPLE OF GEORGIA POWER COMPANY GIVING ASSURANCE OF NO RATE IMPACT WHILE PROVIDING NO SUPPORTING EVIDENCE AND THE RESULTING IMPACT TO CUSTOMER RATES.

[25] https://www.axios.com/2024/02/09/big-federal-purchase-carbon-electricity

A. In its response to STF-DEA-3-6 that asks, "*Provide a forecast of upcoming price increases as a result of the inclusion of Plant Vogtle Units 3 and 4 into rate base as well as the new load acquisitions necessary to serve major new load growth,*" GPC states, "*Plant Vogtle Units 3 and 4…will result in an increase of…$8.95 per month for a typical residential customer…All else being equal, the Company expects that the projected revenues associated with incremental load from known new customer projects, which necessitate the additional capacity requested in the 2023 IRP Update, will fully offset the costs of those resources requested in the 2023 IRP Update and put downward pressure on overall retail rates.*" GPC said the same thing about Vogtle in 2007 and they are still including nuclear in this very IRP Update. Here, in the very same response, GPC exclaims that rates are increasing now, but it won't happen again this time, although it just happened last time. GPC is not held accountable to broken promises.[26] When there is some claw back of revenues, it is much smaller than the increase in unearned revenue GPC receives.[27] Moreover, that still leaves GPC with increased profits from a now-higher authorized ROE that carries well into the future. The result is residential customers' electricity bills climbing at twice the rate of inflation since 2007.

Q. DOES GEORGIA POWER COMPANY'S TRACK RECORD GIVE CONFIDENCE THAT THERE WILL BE NO UPWARD PRESSURE ON RATES?

A. GPC's response to STF-LA-1-11 provides no confidence based on its poor track record of management and its history of flawed analysis favoring gas-fired capacity. GPC maintains its testimony that "***all else being equal, considering the expected load growth and cost of the solutions proposed in this 2023 IRP***

[26] For example, GPC has not accounted anywhere for the risible results from the first full year of its participation on the Southeastern Energy Exchange Market (SEEM). Total first year benefits were only $3.3 million whereas up to $46 million in first year benefits were promised.

[27] The Commission and Staff often point to the $3.5B saved as a result of prudency review in the Vogtle monitoring case. What is not mentioned is that GPC still walks away with $3.4B more in profit than was approved at the time of the Vogtle certification (CPCN) plus GPC receives $3.5B to cover finance costs.

Update, the Company does not expect customer rates to increase." It repeats this again in response to STF-LA-1-16, "*The costs associated with the incremental capacity requested in the 2023 IRP Update, including requests for regulatory asset treatment for certain costs, as well as the retail revenues from the additional load growth that is necessitating the need for this incremental capacity, will impact future rate adjustments for retail customers. Based on the Company's preliminary estimates, all else being equal, the revenues from the additional load growth are expected to exceed the costs of the incremental capacity and put downward pressure on retail rates.*" The risk of authorizing new gas capacity in 2024 is squarely at odds with prudent IRP practice and puts the overwhelming share of risk on the shoulders of GPC customers, not GPC management or corporate shareholders.

Q. WHY ARE THE GEORGIA POWER COMPANY-PROPOSED DER TARIFFS INSUFFICIENT TO ADDRESS THE SHORT-TERM CAPACITY SHORTAGE?

A. In STF-LA-1-10, the data request focuses on Distributed Energy Resource ("DER"). As it relates to tariff DCL-1, on page 43 (lines 1-5) of the Company Direct Testimony, the panel states: "*The participating customer's payment will be calculated as the total cost of the asset less 75% of the net present system value over the life of the asset. This structure (1) ensures all customers will see a benefit based on the discounted system value credited, (2) mitigates the bad debt risk to non-participants, and (3) ensures that participating customers receive resilience benefits.*" The data request is for information on how the discounted system value is derived. In its response to STF-LA-1-10, GPC states, "*The discounted system value was determined using a shared savings model similar to that used to determine DSM incentive levels. We believe the 75% will ensure participating customers receive sufficient incentive to participate in the program while delivering value to non-participating customers. The Company did not*

estimate any bad debt risk associated with the program. Customers will be required to pay for their portion of the asset upfront or over a period of up to 5 years in accordance with the Company's credit policy. At all times the Company will own the asset and the ability to realize the capacity and energy value it provides to the system. Resilience benefits are the ability of the participating customer to continue receiving electric service during a local outage. The value of this resiliency is customer, asset, and location specific. The participating customer will need to quantify the resiliency benefit for their operation. During a local outage, the Company will provide resilience service to the participating customers through the on-site DER. The DER will be monitored at the Company's Operations Center. In addition, the Company will provide preventative maintenance to ensure the DER is appropriately maintained and capable of responding for system or resiliency benefit." This is an overly bureaucratic, complicated, and burdensome DER program that is not likely to be successful, as proposed by GPC. Alternatively, a program like Hawaii Electric Company (HECO) and their highly successful Battery Bonus program[28] should be the model in Georgia. Battery Bonus is simple: the utility pays a cash incentive and provides bill credits for customers to add energy storage (a battery) to a new or existing rooftop solar system. All customers receive an $850/kW payment for the battery in exchange for a10-year commitment of capacity that is discharged from the battery for 2 hours during the evening peak. The popular Battery Bonus incentive quickly reached the cap of 3% of total firm capacity, demonstrating a rapid and proven solution to the acute near-term capacity shortage.

Q. HOW CAN DISTRIBUTED ENERGY RESOURCES HELP TO ADDRESS THE ACUTE SHORT-TERM CAPACITY SHORTAGE CAUSED BY LOAD GROWTH?

[28] https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/rooftop-solar/battery-bonus

A. In a technical brief from the Lawrence Berkeley National Laboratory,[29] they find that an increasing number of states are requiring regulated utilities to file plans that identify distribution system needs, including DERs that can avoid or defer certain types of traditional utility investments cost-effectively. Price-based demand response (DR) is an underutilized resource that could substantially contribute to load flexibility and long-term planning for Georgia's bulk power and distribution systems. "*Table 7 reports the LCOC for price-based DR. Values for TOU rates range from $7/kW-year to $100/kW-year, with the latter being close to the CONE in most areas in the country.* ***This indicates that even the high end of the TOU cost range is most likely cost-effective compared to deploying new generation capacity — especially since CONE does not reflect the incremental cost of transmission.*** *The high-end values are driven by customer marketing and acquisition costs. Unfortunately, the IRPs we studied provided no detail on what these costs entail and why some utilities assume values substantially higher than others do. We compared the LCOC across utilities and rates and determined that load reduction assumptions are the main driver for LCOC. Higher load reduction assumptions typically result in lower costs. Low implementation costs also drive LCOC down.*"

Table 7. Levelized cost of capacity by customer class and rate

Utility ID	Res-TOU	C&I-TOU	Res-CPP	C&I-CPP	Res-VPP	C&I-RTP
1	$80-$100/kW-yr				$33-$59/kW-yr	
2			-$3 to -$8/kW-yr	$81-$86/kW-yr		
3				$22/kW-yr		
4	$16/kW-yr				$10/kW-yr	$8/kW-yr
5	$7/kW-yr	$14 $18/kW-yr				
6	$14-$36/kW-yr	$6-$8/kW-yr				
7				$71/kW-yr		

[29] Lawrence Berkeley National Laboratory, "The use of price-based demand response as a resource in electricity system planning," Juan Pablo Carvallo and Lisa Schwartz, November 2023, see page 13, https://emp.lbl.gov/publications/use-price-based-demand-response

Q. IS GEORGIA POWER COMPANY MARKETING AND OUTREACH FOR DER OPPORTUNITIES SUFFICIENT?

A. In response to STF-PIA-8-4 about whether GPC has coordinated with any Data Center customers to understand how the customer will coordinate rooftop PV and BESS to serve as a resource during periods of peak demand, GPC states, "*As with any new large load customers interested in selecting Georgia Power to provide their electric service, the Company discusses with potential customers the various programs available for Distributed Energy Resource ("DER") assets that can be used as a system resource. In addition, the Company often discusses the benefits and eligibility criteria for potential new large load customers to participate in one or more of Georgia Power's customer renewable programs, such as the Clean and Renewable Energy Subscription ("CARES") Program, the Flex Renewable Energy Credit ("REC") Program, the Retail REC Retirement ("R3") Program, or other renewable program solutions as outlined on Georgia Power's website. For transmission planning purposes, the Company must consider the peak demand of the future load in its analysis.*" GPC's proposed customer-sited DER tariffs are inadequate to garner sufficient interest, and we cannot rely on GPC's lack of analysis, given the critical urgency they express to meet load growth in Georgia.

Q. IN WHOSE INTERESTS IS GEORGIA POWER COMPANY ACTING PRINCIPALLY?

A. GPC is putting its corporate parent shareholders' interests over the interests of Georgia residential customers primarily. In this 2023 IRP Update, GPC proposes a plan that includes 1,400 MWs of new construction gas-fired combustion turbines. There is no consideration of how gas CTs are compatible with the 2050 Net Zero Carbon Target or discussion of the recent $2 billion Fuel Cost Recovery-26 surcharge for natural gas (Docket #44902). There is no mention that new-build gas CTs will enrich GPC's affiliates—all of whom are wholly owned by GPC corporate parent Southern Company save

one—including Southern Power Company, Southern Company Services, Southern Natural Gas Company, and Southern Wholesale Energy, at the significant expense of GPCS ratepaying customers (to their detriment), given lower-cost alternatives that are not being considered in this 2023 IRP Update but are being provided in this testimony as cost effective and pragmatic solutions.

Q. GIVE AN EXAMPLE OF UNDERWHELMING EFFORT FROM GEORGIA POWER COMPANY.

A. GPC has a long history of doing the bare minimum. For example, GPC proposed the Power Credit program in 2007 and by 2019 there were 12 participants out of 2.7 million residential customers. In STF-JKA-6-2, there is a data point on Dispatchable Demand Side Options (DSO) where GPC notes it only assumes 148 MW of DER Customer Programs by 2028, followed by a question of what GPC could do to accelerate the growth of these programs if it would help meet reserve margin requirements? GPC responds saying, "*the Company has developed the two new DER programs (DCO & DCL), both of which should help to accelerate adoption of dispatchable DER. Deploying a DERMS platform will further enable the growth of dispatchable DSOs.*" This disinterest and very low target for Dispatchable DSO is insufficient to the level of alarm that GPC has raised in this 2023 IRP Update regarding the near-term acute capacity shortage.

Q. HOW IS GEORGIA POWER COMPANY REPRESENTING THE NEW-BUILD YATES CTS TO THE COMMISSION?

In the direct testimony page 40 lines 12-17, GPC states, "*To support the timely development of these units, the Company has advanced a reservation fee to the consortium to provide for the procurement of long lead time equipment and required services. These steps help ensure the proposed CT units can be developed in the timeframe needed to support the Company's capacity needs identified in the 2023 IRP Update.*" In STF-LA-1-9-d, the data request is to

"*explain fully and in detail how CT-related development costs that the Company proposes to incur could become not useful or transferable to other projects?*" In its response to STF-LA-1-9 regarding CTs, GPC states, "*Projected amounts of regulatory assets that could occur for CT-related development costs including those associated with the reservation fee that end up not being useful cannot be determined at this time. The Company will take all reasonable steps to recover expenditures and/or maintain the usefulness of equipment and services received.*" GPC is presenting the Yates CTs to the Commission as pre-selected, having already signed a precedent agreement for gas pipeline service possibly from its own pipeline affiliate and also contracted for engineering services with a major EPC contractor and also began procurement with a major turbine OEM, already signed and in effect as of last month, and also signed a Payment for Ecosystem Services agreement for the Yates CTs, and initiated LGIP applications for interconnection request (IR) for the Yates CTs (IC-1166, IC-1167, IC-1168), and even held the IR scoping meeting for Yates CTs six months ago in August 2023, with all this done before the Commission is allowed to review and approve these sunk costs because GPC analysis tells us there is no other choice than the gas-fired Yates CTs.

Moreover, in its response to STF-JKA-2-22, GPC states that, "*construction of the three units will be substantially completed in 32, 37, and 40 months, respectively, assuming a final decision for the 2023 IRP Update is obtained in April 2024.*" The Commission should ask whether the EPC Agreement that GPC executed in January 2024—ahead of Commission review and approval—has a mechanism to deal with current procurement lead times of 38 months for 230 kV breakers, which is the voltage at which the Yates CTs will interconnect to the grid. These 230 kV breakers are in high demand due to offshore wind project projects and utility stockpiling for critical reliability concerns.

Finally, note that in response to STF-JKA-2-2 supplemental filing, GPC states, "*Due to one of the proposed CTs expecting to achieve commercial operation in 2027, rather than 2026, approximately 200 MW of Other BESS were advanced to 2026 to fulfill the resulting projected capacity need for the winter of 2026/2027.*" This demonstrates that GPC can advance the timeline of BESS resources ***if it wants to***, but it chooses not to in favor of gas-fired resources.

Q. WILL INTERIM ERIS CAPACITY LIMIT THE YATES CTS FROM HELPING TO ADDRESS THE ACUTE NEAR-TERM ENERGY SHORTAGE?

A. In response to STF-GS-2-2, GPC states, "the Company plans to designate all 1,350 MW of proposed Plant Yates combustion turbines, and the facility will be limited to 600 MW of firm output until all identified transmission improvements are in-service by summer 2028. The requested energy resource interconnection service (ERIS) does not contribute to or increase the likelihood of transmission constraints or curtailments." GPC then states in STF-GS-2-1 that, "neither ERIS nor NRIS convey any delivery rights or grant any form of firm or non-firm transmission service." But that is only part of the definition in the Open Access Transmission Tariff.[30] GPC leaves out the critical part that ERIS makes one "eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission Provider's Transmission System ***on an as available basis***." The solution GPC proposes to address load growth is to build

[30] Energy Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

the three Yates CTs, even though GPC admits in STF-GS-2-2 that they would only contribute 600 MW to the short-term capacity need identified in this IRP Update, reaching full firm output three years later than needed. The requested service of ERIS will in fact throttle the Yates CTs from helping to address the acute short-term capacity shortage caused by load growth. GPC has stated that BESS resources can be brought online more quickly than gas. Indeed, BESS would have been selected far more often if given fair treatment in GPC's analysis.

Table 3-3. Proposed CT Units: Annual Potential Emissions for Each Fuel

	Potential Emission Rates (Three CTs)(1)(2)				
Pollutant	Normal Operation (tpy)	With Startup and Shutdown (tpy)	Normal Operation (tpy)	With Startup and Shutdown (tpy)	Potential to Emit (tpy)
	Natural Gas		Distillate Oil		
NO_X	218.1	293.0	403.5	**504.8**	504.8
CO	190.9	946.2	245.4	**3,013.8**	3,013.8
VOC	61.1	301.9	56.2	**1,041.2**	1,041.2
TSP	37.9	43.6	192.8	**251.0**	251.0
PM_{10} / $PM_{2.5}$	130.3	131.3	264.6	**316.4**	316.4
SO_2	30.4	29.6	28.8	27.4	30.4
H_2SO_4	46.6	45.4	44.0	42.0	46.6
Lead	0.01	0.01	**0.26**	0.25	0.26
GHG (CO_2e)	2,585,053	2,516,687	3,060,060	2,917,477	3,060,060

(1) See **Appendix C** for detailed calculations.
(2) See **Section 6.1.2** for detailed discussion of startup and shutdown emissions.

The flaws in the MG0 case mean all related studies like the transmission study update—which depends on accurate generation dispatch—will be flawed immediately upon delivery by GPC in two weeks. GPC confirms yet another flaw in its response to STF-DEA-8-7 by stating, "*Battery charging studies were not performed as part of the transmission screens filed in the initial IRP Update filing and transmission supplemental filing.*"

Q. ARE BATTERIES BENEFICIAL TO THE GRID?

A. In response to STF-JKA-5-10-b, GPC states, "*Generic BESS resources may be able to provide multiple use cases subject to the availability of transmission and general system conditions. The proposed BESS facilities can provide energy arbitrage benefits and capacity value benefits. During real time operations, the BESS may also be able to provide operating reserve benefits and similar benefits during periods when the adjacent solar resources are not utilizing the interconnection capacity. The Company's economic analysis for BESS resources conservatively assumed only energy arbitrage and capacity value benefits.*" However, when GPC reduces the value stack for BESS to only energy and capacity, this unfairly limits what a BESS is able to provide. GPC now has years of experience with BESS on its system; there are no insurmountable technical barriers to deployment.

Q. WHAT DOES GEORGIA POWER COMPANY SAY ABOUT BATTERY STORAGE AS A SOLUTION TO ITS CAPACITY SHORTAGE?

A. GPC testified (Direct Testimony, p.37 lines 9-11) that, *"The time to construct BESS is shorter than other types of generation and, therefore, can be more quickly deployed…*" GPC also acknowledged that BESS provide tremendous benefits and value to the grid. However, GPC is proposing that the vast majority of the 6,600 MWs requested will come from fossil generation that will become stranded assets well before the end of their useful life, saddling ratepayers with avoidable debt. Note that half of the load requests are outside the service territory of GPC, per responses to STF-DEA-3-6.

Furthermore, in its response to STF-JKA-4-13-b, GPC states, "T*he Company is confident that the BESS will serve as a reliable and economical solution for the anticipated capacity needs…BESS technology is being demonstrated as a reliable generation option across the world. CAISO and Electric Reliability Council of Texas ("ERCOT") have over 10.4 GW of BESS in operation with another 75 GW*

planned. The ease of installation of BESS, compared to alternative technologies will allow the technology to scale at an unprecedented pace...The Company will utilize tier 1 suppliers for its BESS projects that have a proven track record and a portfolio of gigawatt hours of battery storage deployed. Initial performance testing of the battery will ensure the battery meets required performance standards...With the passing of the IRA, and the significant advancement in battery technology, the economic and reliability proposition for BESS has never been greater for customers." BESS can be deployed more quickly than gas-fired resources, even on brownfield sites.

Q. WHY IS IT IMPRUDENT TO APPROVE THE CERTIFICATION OF YATES 8-10?

A. GPC is presenting the Yates CTs as pre-selected, having already signed a precedent agreement for gas pipeline service possibly from its own pipeline affiliate and also contracted for engineering services with a major EPC contractor and also began procurement with a major turbine OEM, already signed and in effect as of last month, and also signed a Payment for Ecosystem Services agreement for the Yates CTs, and initiated an LGIP application for interconnection request for the Yates CTs, and even held the interconnection scoping meeting for Yates CTs six months ago in August 2023, with all this done before the Commission is allowed to review and approve these sunk costs because GPC analysis tells us there is no other choice than the gas-fired Yates CTs. It is noted that GPC has not deigned fit to respond to the comment: "*It is noted that O.C.G.A § 46-3A-3 lists "Actions prohibited without a certificate of public convenience and necessity" and this includes "enter[ing] into a long-term purchase of electric power" and would infer prohibition of the further step of re-marketing a contracted PPA for two (2) years prior to capacity need. GPC is presenting the PPAs with Mississippi Power Company and Santa Rosa Energy Center LLC as pre-selected and only seeking Commission review after entering*

into the contracts." It is further noted that one day before intervenor testimony is due, GPC sought favorable treatment for imprudently incurred gas development costs in its supplemental update to STF-LA-1-23 stating, "*The Company is requesting regulatory asset treatment for development costs not useful or transferable to other projects in the event the Company's request to develop three simple cycle combustion turbines (CTs) at Plant Yates is denied. The estimated maximum regulatory asset amount, if the project is denied, would equal REDACTED of projected development costs and a REDACTED cancellation cost.*" Note that GPC has a history of pre-selecting projects and poor analysis. GPC was pre-planning for Vogtle Unites 3&4 well before the 2007 IRP, "*Georgia Power Company is actively pursuing the option for deploying advanced nuclear generation at the existing Vogtle plant site. The Company filed an Early Site Permit (ESP) application with the Nuclear Regulatory Commission (NRC) in August of 2006 and anticipates filing an application for a Combined Construction Operating License (COL) in 2008.*"[31] GPC went on to say, "Because of the long lead times and licensing requirements for nuclear plants, Georgia Power must continue to invest to maintain nuclear as a viable option for new base-load capacity. ***If the company does not continue to invest in these initiatives, nuclear will not be a viable option in the 2015/2016 timeframe, and Georgia's citizens will be denied an option that could potentially result in significant savings.***"

Q. PLEASE PROVIDE A CONCLUDING SUMMARY OF YOUR DIRECT TESTIMONY.

A. In my direct testimony, I demonstrate how GPC is using flawed analysis in its application before the Commission to certify the Yates CTs, resulting in an unjust cost shift onto residential ratepayers in particular and an imprudent plan to build new gas-fired generating assets. These new gas plants are at risk of becoming stranded assets whose costs will be further shifted onto residential ratepayers as

[31] Docket #24505, Georgia Power's 2007 Application for Approval of an Integrated Resource Plan, page 6-5

regulatory assets. I also provide many examples of GPC acting anticompetitively in ways that results in fewer choices in the open market. And I provide practical solutions to help GPC meet the acute near-term capacity shortage due to load growth. I urge the Commission to reject this *ex post facto* Yates CT application due to its flawed 2023 IRP Update analysis and pre-determined outcomes, and to require GPC remove its own barriers to high-value solar and storage projects that are ubiquitous in its modeling, operations, contracting, and planning practices.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

VERIFICATION

The undersigned, Peter Hubbard, affirms on this 15th of February, 2024 under the penalties of perjury that the answers in the foregoing Direct Testimony in Georgia Power Company's 2023 Integrated Resource Plan Update and Application for Certification of Plant Yates Units 8-10 (Docket #55378) before the Georgia Public Service Commission are true to the best of his knowledge, information, and belief.

Peter Hubbard 2-15-24

Peter Hubbard

Georgia Center for Energy Solutions

On 2/15/24, Peter Hubbard personally appeared before me and presented a valid GADL as proof of identity.

Chandler Daniel Notary.

My notarial commission expires 12/5/26.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the within and foregoing Direct Testimony on behalf of the Georgia Center for Energy Solutions in Georgia Power Company's 2023 Integrated Resource Plan Update and Application for Certification of Plant Yates Units 8-10 (Docket #55378) upon all parties listed below via electronic service and addressed as follows:

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This 15th day of February 2024.

2-15-24

Peter Hubbard
Georgia Center for Energy Solutions

Georgia Center for Energy Solutions
55 Leslie St SE
Atlanta, GA 30317
404.226.4448
peter@georgia-ces.org

On 2/15/24, Peter Hubbard personally appeared before me and presented a valid GADL as proof of identity.

Chandler D. Notary.
My commission expires 12/5/26.

CHANDLER DANIEL NOTARY PUBLIC Exp. 12/05/2026 DEKALB COUNTY, GA