BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of:	)	
GEORGIA POWER COMPANY'S	)	**DOCKET NO. 44280**
2022 RATE CASE	)	

<u>POST-HEARING BRIEF OF THE PUBLIC INTEREST ADVOCACY STAFF</u>

I. Introduction

Georgia Power Company's request is unprecedented, as will be the impact on its customers if the request is granted. The dollar figure was mentioned throughout the hearings: just shy of $3 billion over a three-year alternative rate plan. But the Company's request for a massive rate increase cannot withstand scrutiny. Over a billion dollars as a result of the Company's demanding a return on equity that is way out of line from what other electric utilities have been awarded in recent years. The Company proposes $2 billion dollars in capital investment for a grid investment plan that isn't needed and hasn't been shown to improve reliability and which will cost ratepayers hundreds of million during the 3 year period and much more in subsequent years. Other significant increases relate to Company proposals that violate a fundamental principle of the regulatory compact that the captive customer should not be forced to pay for expenses that do not relate to the provision of safe and reliable electric service. In summary, the Company has not carried its burden to demonstrate that the bulk of its proposed rate increase is necessary.

The timing of Georgia Power's request adds to the burden. Looming in the very near future are additional increases as a result of Vogtle Units 3 and 4 becoming part of rate base and a $1 billion fuel cost under-recovery. The total impact on a typical residential customer of the Company's requests could be in the range of $55 to $60 per month or approximately 45 percent increase. Tr. 1377. There is a stark difference, however, between the proposed increases that are part of this rate case and the cost increases that ratepayers will face next year. That difference is that the Commission will have far less discretion to disallow increases related to Vogtle 3 and 4 entering rate base and fuel cost recovery as compared with the discretion that it has in this case to disallow the Company's unreasonable and unsupported requests.

But the Company feels like it has an ace in the hole. Even though its dollar request is enormous, its evidence flimsy and its arguments contrary to sound and well-established ratemaking principles, Georgia Power confidently sticks to its guns because its position is that the Commission needs Company sign-off for any alternative rate plan. And Georgia Power knows that the Commission likes alternative rate plans, and for good reason because both the Company and its customers have benefited from alternative rate plans in the past. So, Georgia Power asks for the world and says that if the Commission doesn't give in, then there can be no alternative rate plan. The problem with giving in, however, is that doing so overlooks a fundamental truth about alternative rate plans, which is the same fundamental truth that can be said about any ratemaking mechanism: an alternative rate plan is only as good as its terms and conditions. If an alternative rate plan has fair and reasonable terms and conditions, then it will benefit both the Company and its customers. If an alternative rate plan has unfair and unreasonable terms and conditions, then it will not. As long as the Company insists upon the latter, the Commission has to be willing to consider a traditional rate case in order to protect consumers from the excessive rates proposed by the Company. Unless the Commission is willing to order a traditional rate case in the event that the Company won't agree to a reasonable alternative rate plan, Georgia Power will effectively be allowed to dictate the terms of its own regulation.

The Public Interest Advocacy Staff has presented the Commission with a reasonable alternative. Staff's proposal appropriately balances the interests of Georgia Power and its customers by allowing the Company the ability to earn a fair return while avoiding the rate shock that will occur if the Commission blesses the Company's draconian proposal. Staff reaches this balance through a return on equity that is more in line with what electric utilities have been awarded throughout the country, by holding the Company to its burden of proof on issues like its exorbitant Grid Investment Plan and by developing an accounting order where customers have a reasonable opportunity to benefit if the Company operates efficiently, as opposed to Georgia Power's plan where the benefits of any efficiencies flow overwhelmingly to the Company. In addition, Staff's proposal saves ratepayers from having to pay for expenses that don't contribute to the provision of safe and reliable electric service, including but not limited to costs related to electric vehicles and stock-based compensation for highly compensated Company executives.

Georgia Power may not agree to Staff's proposed alternative rate plan. If the Company is not willing to accept any reasonable alternative rate plan, the Commission should order a traditional rate case that is consistent with the recommendations presented by Staff. Regulatory lag will still provide the Company with the incentive to operate efficiently, and if Georgia Power wishes to file again for a rate case, then the Commission should once again scrutinize the request to ensure that rates remain just and reasonable. Once the Company understands that a traditional rate case is still a realistic option, then perhaps its demands on what terms and conditions need to be included in an alternative rate plan will be more reasonable. If that were to occur, then the Commission would once again have the opportunity to approve an alternative rate plan that aligns the interests of the Company and its ratepayers.

This brief does not address every adjustment that Staff proposed to Georgia Power's rate case. Instead, Staff focused on a number of key issues. For the issues not addressed in this brief, Staff stands on the testimony it presented to this Commission. A schedule showing all of Staff's proposed adjustments is attached hereto as Exhibit 1.

II. Alternative Rate Plan

Staff's proposed alternative rate plan aligns the interests of the Company and ratepayers far better than the plan proposed by the Company. First, Staff's proposed alternative rate plan consists of a 200 basis point earnings band that is symmetrical around the Staff's proposed return on equity. Tr. 1374. This earnings band, which is narrower by 50 basis points than Georgia Power's proposed band, allows ratepayers a far greater likelihood to benefit from an efficiently operated system. While there is always a lot of discussion about what sharing should take place above the band, it is important to consider that no sharing takes place inside the band. That is, 100% of earnings inside the band go to shareholders. So, how long the Company gets to stay inside the band has an effect on what benefits ratepayers are likely to see from any efficiencies. Under Georgia Power's proposed band, the Company can earn $534 million dollars above the bottom of the band before customers receive one shared dollar. Tr. 4019-20. The Company provided no explanation as to why that level of incentive was necessary for it to operate efficiently.

Staff's proposal for earnings above the band provides the Company with an appropriate incentive to operate efficiently. Instead of the sharing between ratepayers and shareholders for earnings above the top of the band, Staff recommends that such earnings be applied for the accelerated recovery of deferred costs and regulatory assets. This proposal still provides the Company with an incentive to operate efficiently. Georgia Power witness, Abramovitz, admitted that writing down assets provides the Company with cash sooner. Tr. 4022. Abramovitz also acknowledged that operating efficiently to provide refunds to customers is an incentive. *Id.* Therefore, Staff's proposed earnings band provides benefits to both ratepayer and the Company and effectively incentivizes the Company to operate efficiently.

II. Return on Equity

The Staff's proposed alternative rate band is centered around a return on common equity that is demonstrably more reasonable than the ROE recommended by the Company. Staff witness Mike Gorman recommended a return on common equity of 9.45%, within the range of 9.00% to 9.90%. Tr. 3515. Gorman's recommended a rate of return of 6.83% and 6.84% for the test year ending July 31, 2023 and calendar year 2023, respectively. *Id.* Based on a capital structure reflecting a 51% common equity ratio, Gorman recommended an overall rate of return of 6.57% and 6.61% for 2024 and 2025, respectively. *Id.* Gorman did not challenge the Company's capital structure reflecting a 56% common equity ratio for the calendar year 2023. Tr. 3516.

In comparison, Georgia Power witness Coyne recommends a return on common equity of 11.0%. Tr. 631. As Gorman explains in his testimony, "the industry authorized returns on equity for electric and gas utilities have ranged between 9.35% to 9.78% for the period 2014-2022 to date and, since 2020, the industry authorized returns on equity have averaged below 9.50%." Tr. 3517. The Company did not dispute the accuracy of Gorman's testimony on this point. That is, it is undisputed that Gorman's recommended return on common equity of 9.45%

is within the range of authorized returns on equity for electric and gas utilities over the past nine years, and is consistent with the average of ROEs awarded since 2020. The flip side of this statement is that it is undisputed that Coyne's recommended ROE is outside the range of authorized returns over the past nine years and is substantially higher than the average since 2020. Similarly, Gorman's recommended equity ratio of 51% is close to, and actually a little higher than the average and median state authorized equity ratios for electric utilities since 2010. Tr. 3543. In contrast, Coyne's recommended common equity ratio of 56% is far outside the norm. Nevertheless, the Company, in an apparent attempt to outdo the proverbial pot calling the kettle black, repeatedly accused the Staff of being "radical." The word "radical" is defined as meaning "departing from the usual or customary." American Heritage. Gorman's recommendation does not depart from the usual or customary authorized returns that utilities have been awarded. Coyne's does. With respect to the returns and capital structures that have been approved for electric utilities throughout the country in recent history, it is plain that it is the Company that is presenting this Commission with a radical proposal.

The Company's spin on this debate is that Staff's recommendation is radical, not because it is out of step with what state commissions have authorized for utilities throughout the country, but because it is out of step with the level of authorized return that Georgia Power has grown accustomed to. In other words, Georgia Power is entitled to an inflated ROE because it has been awarded such an ROE in the past. The unfairness to consumers of this request is apparent. All things being equal, customers will pay higher rates if the Commission approves a higher return, and the Company's proposal is for ratepayers to continue to pay more as a result of an inflated authorized ROE simply because these customers have been paying more for years.

A comparison to the authorized returns for other utilities effectively shows how radical the Company's request is. But that is not the totality of the analysis. Gorman's testimony detailed the numerous flaws in Coyne's recommendation. These flaws resulted in a recommended ROE that was outside the norm. As Gorman explained,

- Coyne's constant growth DCF results are based on unsustainably high growth rates;
- Coyne's CAPM is based on inflated market risk premiums;
- Coyne's CAPM is based on beta estimates that do not reflect the low risk nature of utility investments;
- Coyne's Bond Yield Plus Risk Premium studies are based on an overly simplistic inverse relationship between equity risk premiums and interest rates, which produces inflated equity risk premiums;
- Both Coyne's CAPM and Risk Premium studies are based on projected interest rates that are highly uncertain, and
- Coyne's Expected Earnings analysis is unreasonable because it measures the book accounting return, rather than the market required return.

Tr. 3579.

In response to these valid criticisms, Georgia Power resorts to a scare tactic. Namely, if the Commission adopts Gorman's recommended ROE, then the Company will have its bond rating downgraded. There are two problems with the Company's scare tactic. *First*, it's unlikely. Staff's witness recommended an ROE that is consistent with what other utilities have been authorized to earn. So, there is no basis for sounding an alarm for Georgia Power. Not only that, but the authorized return is not the sole consideration that ratings agencies consider. As Staff witness O'Donnell testified metrics only make up 40% of what goes into a credit rating.

Tr. 3686. The other 60% is made up of regulatory framework (25%), ability to recover costs and earn a return (25%), and diversification (10%). *Id.* *Second*, the costs to consumers of a downgrade to the Company's bond rating is a small fraction of the cost to consumers of adopting Georgia Power's proposed ROE. In fact, O'Donnell testified that the ratio of these two costs is greater than 12 to 1, meaning that the higher ROE would have an impact of more than twelve times the impact of downgrade to the Company bond rating. Tr. 3685. Relative to the national average, ratepayers would pay $1.26 billion more if Georgia Power's requested authorized ROE is approved. *Id.* In comparison the increased costs to ratepayers of a downgrade would be $96 million over the next 20 years. *Id.* So, the Company's pitch on ROE boils down to this: ratepayers should be forced to pay $1.26 billion in additional costs over the next three years to incrementally reduce the possibility that they will have to pay a small fraction of that amount over the next 20 years. The Company's proposal is the epitome of the cure that is worse than the disease.

Staff's recommendation on ROE does not expose the Company to undue risk. To the contrary, Staff's recommendation is squarely in line with the authorized returns that utilities have been awarded in recent years. Also, there are numerous other considerations that factor into a utility's bond rating; consequently, it would be ill-conceived to award an inflated ROE in the hopes that it would provide security against a downgrade. Finally, because customers are being asked to pay exponentially more on the higher ROE than a downgrade would have ever cost them, the Company's proposal is contrary to ratepayer interests and fundamentally unfair.

III. Grid Investment Plan

Georgia Power's Grid Investment Plan includes a Distribution Investment Plan ("DIP") and a Transmission Investment Plan ("TIP"). Georgia Power proposes to continue its GIP in the amount of $2.3 billion from 2023 to 2025. Tr. 1563. Georgia Power has not demonstrated that there is an urgent need for the substantial investment it proposes to address system reliability. Moreover, the Company has not presented the necessary cost-benefit analyses to demonstrate that the benefits to consumers will outweigh the significant financial burden that customers are being asked to bear. The Company has not even demonstrated that there will be significant improvements to system reliability from many of the measures in its plan. Finally, the Company has not considered far more cost-effective measures to maintain a safe and reliable system. For all of these reasons, the Commission should reject the Company's proposed Grid Investment Plan. And in rejecting the plan, the Commission should find comfort in knowing that the Company has managed to operate its system safely and reliably, and that the rate case, even with the rejection of the GIP, includes significant incremental capital for system reliability beyond historical averages pre-GIP.

Georgia Power did not meet its burden to show that its proposed Grid Investment Plan is necessary. The record shows that Georgia Power has maintained system reliability consistent with industry standards. Tr. 1565 Moreover, Georgia Power customers have not identified system reliability as a concern. To the contrary, customer satisfaction surveys rate the Company's reliability higher than they rate the Company overall. *Id.* Consistent with these survey results, customers have indicated that they don't want to pay anywhere near the kind of money the Company is requesting in this rate case for reliability improvements. Georgia Power conducts "willingness to pay" research on reliability. That research shows that customers are not willing to pay more than 1.7% more for a 50% increase in reliability. *Id.* Here, Georgia Power proposes a far greater increase in rates for a much smaller gain in reliability. Staff witnesses Alvarez and Stevens estimated a revenue requirement increase for the $7.5 billion GIP at the time Georgia Power first presented in 2019 will be 10%.[1] In short, system reliability, while important, is not an urgent problem, and even if it were, the Company has not shown that the GIP is a cost-effective solution.

Georgia Power has not supported GIP with the necessary cost-benefit analyses. For TIP, the Company has failed to project reliability improvements. For DIP, the benefits cannot be identified at this time because the program was implemented concurrently with vegetation management efforts, therefore, there is no way to know how much of any reliability improvements were due to the DIP. The Company has failed to take the most basic step imaginable for seeking approval of any investment large or small, which is to establish that the benefits outweigh the costs.[2] If the benefits of an investment don't outweigh the costs, then obviously there is no reason to make the investment. And again, that would be the case for any investment large or small. Here, we're talking about an investment in the billions of dollars. If Georgia Power customers were able to choose another provider, and the Company spent billions on a program without doing a cost-benefit analysis and it turned out the program's costs outweighed its benefits, then many customers would likely leave for another provider to avoid being burdened with the costs of a bad investment. That Georgia Power customers don't have that choice means they should not be subjected to that risk.

To protect ratepayers from the potential of a sizable investment without sufficient benefits, the Commission should not approve additional investment for GIP, until it has three years of post-deployment experience to determine if the GIP results in actual reliability

[1] See Exhibit PA/DS-5 for a summary of calculations.

[2] The Customer Benefits Study the Company completed on its DIP is not a benefit-cost analysis, as the Company agreed in its response to STF-WG-1-8(f). Instead, as Staff notes, the Customer Benefits Study only estimates the customer costs of multiple scenarios of Company-defined DIP package applications, with one such scenario identified as lowest cost to customers relative to the others. Such an analysis does NOT indicate that the identified lowest-cost scenario delivers benefits in excess of costs, or indeed that any DIP package delivers benefits in excess of costs.

improvement relative to the cost. This analysis should be completed by an unbiased expert for each of the Company's reliability initiatives individually.

In summary, Staff recommends that the Commission reject TIP in its entirety. Instead of prematurely replacing functioning equipment based on age, the Company should determine whether equipment should be replaced based on the objective, periodic, diagnostic testing the Company already employs. Staff also recommends that the Commission reject the circuit hardening and undergrounding packages, which make up approximately 85% of the DIP. In particular, the Commission should reject DIP circuit hardening and undergrounding packages as cost-inefficient. For any components of DIP the Commission approves, Staff recommends that the Commission direct the Company to document SAIDI and SAIFI projections in 2032 and to hold the Company accountable for those projections. The need for accountability is particularly important in light of the Company's clarification during discovery that the 2032 SAIDI and SAIFI projections should not be considered targets. Tr. 1625. Such clarification does not instill confidence that DIP-related reliability improvements will be realized. Staff recommends that the Company employ more aggressive vegetation management programs and more rigorous worst-performing circuit programs in place of capital intensive, cost-ineffective DIP packages.

A. Transmission Investment Plan

The cornerstone of the TIP is replacing equipment based on the age of the equipment as opposed to replacing it based on the equipment failing a diagnostic test. This practice has been referred to by Staff's experts as "prematurely replacing equipment." Prematurely replacing equipment is vastly more expensive than replacing equipment based on the results of diagnostic testing, and the reliability improvements of this approach are very small. The Company did not provide reliability improvement projections or cost-benefit analyses for the TIP or the premature replacement practice. Staff does not agree with the Company's unsupported position that such projections or analyses are impossible to provide.

The actual operating condition of transmission and distribution ("T&D") equipment as measured by periodic, objective testing and inspection programs should be the primary drivers of replacement. This is so because not all equipment lasts the same amount of time. If the expected life for a particular equipment type is 40 years on average, that does not mean that all of the equipment will fail at 40 years. In practice, some units will fail almost immediately and other units will last twice as long as the average. Georgia Power's defense that as equipment gets older the likelihood that it will fail increases is misguided because it has no limiting principle. Equipment that is three-years old is incrementally more likely to fail than equipment that is two-years old, but that is obviously no reason to replace the three-year old equipment. The absurdity of this example shows the flaw in Georgia Power's reasoning. To be clear, Georgia Power, as it should, replaces units that fail diagnostic tests, regardless of age. But what that shows is that when Georgia Power replaces a unit based on age, that necessarily means that the unit has passed its most recent diagnostic test. Because if it hadn't, Georgia Power would have already replaced it. Even though the unit is working, and may continue to work for many years to come, the premature replacement approach proposed by the Company would result in that functioning unit being scrapped. Any plan that is based on replacing functioning equipment is going to be needlessly expensive.

Georgia Power defends its approach by criticizing the effectiveness of the tests. But these criticisms do not add up. As just one example, the Company has likely completed thousands and thousands of tests on power transformers over the last ten years. Tr. 4058. Yet these thousands of tests failed to accurately predict that a transformer would continue to provide reliable service in just 108 instances over that same ten-year period. Robinson's criticism fails to consider the total number of tests performed and only considers those instances in which the equipment ultimately failed. Tr. 3983. This is error. To evaluate the accuracy of the tests, it is necessary to consider all of the tests it has performed over the ten years and compare that to the 108 instances in which it didn't perform accurately. When the proper comparison is performed, it is clear that the percentage of inaccurate tests is very small. In fact, such tests are routinely employed by all utilities precisely because of their extremely accurate predictive capabilities.

In evaluating whether prematurely replacing equipment is worth it, it is also necessary to consider the consequences of an equipment failure. In other words, the record clarifies that the age of equipment does not establish whether it is likely to fail, and that diagnostic testing is reliable and can be used to determine whether equipment is still functioning. But because the testing isn't perfect, it is also important to consider what happens in those rare instances in which a piece of equipment fails, despite having passed a diagnostic test. The record shows that equipment failure typically does not result in an outage because of the redundancy built into the system. Electric utilities are required to plan and operate their transmission systems using the N-1 criterion to comply with the NERC reliability standards. This means that the power system will operate safely and reliably following an outage of a single critical facility without causing thermal overloads or voltage problems on the facilities that remain in service. This also means that there is inherent redundancy in the system available to accommodate singular failures of critical network elements and equipment with no service interruptions for customers. Furthermore, the transmission system can operate reliably even with two network elements out due to options available to system operators such as temporary generation redispatch or network reconfiguration.

The Company also cites the incremental costs of emergent replacement as a justification for premature equipment replacement. But only replacements of equipment that fails in service *and* causes a service interruption constitute replacements so emergent as to incur large incremental cost multiples. Such failures are incredibly rare. Tr. 1577, Table 2. Thus while some amount of incremental emergency replacement cost can be avoided through premature replacement, the infrequency of emergency replacements makes these incremental replacement costs very low relative to the extreme incremental cost of premature replacement.

The failure of Georgia Power to perform a cost-benefit analysis is fatal to its effort to carry its burden. The Company maintains that such an analysis can't be done. But that's demonstrably not so. In fact, Staff's witnesses conducted a cost-benefit analysis. *Id.* The Company's protests amount to nothing more than saying that there are contingencies that would make the cost-benefit analysis imperfect. But that doesn't distinguish TIP from any other issue before this Commission that is reliant on experts making projections. In the context of a subscription price, Georgia Power witness Larry Legg testified in this proceeding that "the only thing we know about a forecast of assumptions is it's wrong . . . but it's based on the best available information we have at the time." Tr. 4303. That the forecast will not be precise was not reason for Georgia Power not to engage in the process based on its best available data, and that is what the Company should be required to do for its TIP as well. If Georgia Power can avoid having to do a cost-benefit analysis for a program any time it claims that doing so is impractical, it creates an incentive for the Company to not provide adequate support for its requests, and it exposes customers to the risk of having to pay for inefficient programs that were not robustly vetted prior to approval.

The Commission should reject Georgia Power's request to continue TIP. Testing is a less expensive way to ensure system reliability. Through its equipment testing and inspection programs, Georgia Power has historically followed utility best practices for identifying equipment in need of replacement or repair, and the Company should continue to follow these.

B. Distribution Investment Plan

The Commission should also reject the circuit hardening and undergrounding components of the Company's proposed DIP. The DIP consists of six investment "packages" the Company has defined to be applied to circuits to improve their performance. As mentioned above, the prudent course of action would be to secure at least three years' data on the reliability improvements delivered by DIP packages implemented to date before drawing any conclusions on package effectiveness. At this point, the Company has not isolated the beneficial impacts of an individual DIP package from the other packages implemented and from vegetation management actions taken on the same circuits. Such isolation is required in order to evaluate which packages, if any, are cost-effective. Early experience indicates that there is reason to be concerned about the program's effectiveness because the Company has walked back its reliability projections from 2019 when it first proposed the DIP. In the current DIP, the Company revises its SAIDI projection to reflect a 23.1% deterioration from initial projections.

The Commission should reject the circuit hardening and undergrounding components of the DIP because they are not cost-effective. Staff witnesses conducted cost-benefit analyses of both of these programs and determined that ratepayers will receive only \$0.45 in value per \$1 rate increase related to circuit hardening. The value is even less for undergrounding at \$0.36 per \$1 rate increase. For any remaining DIP component, the Commission does not reject, the Commission should direct the Company to document projections for SAIDI and SAIFI in 2032, and to hold the Company accountable for securing those projected reliability improvements. As filed, there is no consequence for the Company not meeting its projections. Before the Commission approves additional investments for this purpose, the Commission should develop a mechanism that holds Georgia Power accountable if its plan does not provide the projected benefits to customers. The Commission should also require formal policies, budgets, and annual performance reporting for the Company's vegetation management and worst performing circuit programs.

Staff's opposition to DIP does not mean that it doesn't recognize the importance of system reliability. But the DIP ignores more cost-effective ways to improve reliability. In particular, almost all utilities employ more aggressive vegetation management programs and more rigorous worst-performing circuit programs. The Company's Optimization Model and its resulting DIP do not consider such programs.

Given Georgia's extended growing season, a more aggressive, formal, and consistent vegetation management program is the first place we would concentrate to secure cost-effective improvements in reliability. Indeed, an examination of outage cause data 2017-2021 indicates that vegetation contact was one of the most common causes of service interruptions, amounting to one-fifth of all service interruptions 2017-2021.[3] Staff witnesses Alvarez and Stevens explained that this is consistent with their experience across utilities. Consistent with this experience, the Commission should require strict compliance with a four-year vegetation management cycle, and may also wish to consider related annual reporting requirements.

A worst-performing circuit program is commonly used, and it involves identifying which circuits are experiencing the most interruptions, doing a root cause analysis, and developing a

[3] Trade Secret Attachments F through J provided in response to STF-WG-1-30. Includes all vegetation contact.

remediation plan. The Company has no formal criteria for identifying the worst-performing circuits. The Company should be directed to develop written policies to formalize its program, including clear criteria for identifying circuits for additional attention annually; standards for completing root-cause analyses; standards for developing remediation plans; and standards for reviewing plans and authorizing spending, as well as standards for tracking spending, projects, and results. The Commission should establish both specific budgets for the program, and personnel/organizational accountabilities for program administration, root cause analyses, and remediation plan development and implementation. The Commission may also wish to consider establishing annual reporting requirements for this program as well.

C. Distributed Energy Resource Management System

A distributed energy resource management system (DERMS) is a software package which can, when combined with data from and remote control of customer and field equipment, help a utility meet the challenges of increasing levels of distributed energy resources on its grid. Very few utilities have installed DERMS, due largely to the low penetration of DER on most utilities' grids. Georgia Power is requesting $100 million to install DERMS in this rate case. Given that the cost to install DER capacity is likely around $1.8 million per MW,[4] the cost to implement DERMS is roughly equivalent to a minimum 6.7% cost premium on top of the costs the Company or its customers incur to install DERs. This represents a high level of overhead for very little benefit. The Commission should reject the Company's capital request to install DERMS in its entirety due to the small incremental benefits and relatively low DER penetration the Company expects on its grids by the end of the rate case period.

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[4] U.S. Energy Information Administration. "*Average U.S. Construction Costs for Solar Generation Continued to Fall in 2019*." Available via internet at https://www.eia.gov/todayinenergy/detail.php?id=48736. July 16, 2021.

IV. Electric Vehicle Make Ready and Charging Stations

The Company proposes to increase substantially the dollar amount that ratepayers will have to pay for capital expenditures related to electric vehicle ("EV") transportation. These expenditures include (1) investments in EV charging facilities and infrastructure upgrades, (2) administrative cost recovery, (3) infrastructure maintenance, and (4) rebates to accommodate the growth of EV transportation. Tr. 78. Specifically, the Company requested $30 million per year for EV capital infrastructure spending for plan years 2023 through 2025, nearly quintupling the $8 million approved for such expenditures in the 2019 rate case. Tr. 1315-17 The majority of that request, $27 million per year, is for the Company's Make Ready program *Id*. The remaining $3 million is for infrastructure upgrades for the Community Charging program. Tr. 1324 The Make Ready program, if continued for the next decade, will increase the revenue requirement by close to half a billion dollars. Tr. 1316

The Commission should reject the Company's proposal for two reasons. *First,* the proposal violates the regulatory compact. Under the regulatory compact, the utility makes investments on behalf of customers, who in turn pay the company for the investment and for a reasonable return on the investment. Unfortunately, the Company's proposed Make Ready program and EV Charging Stations would, in fact, pass on to captive ratepayers costs that primarily benefit participants in the program. Because only a tiny percentage of retail electric ratepayers drive electric vehicles, the overwhelming majority of customers do not benefit directly from the programs. Instead, captive ratepayers will be subsidizing the Make Ready program and EV charging stations. *Second,* it is expected that there will be a competitive market for new charging stations, so it is unfair and inappropriate regulatory policy to allow Georgia Power to expand its monopoly on the backs of regulated ratepayers. The purpose of this case is to provide the Company with the necessary capital to provide reliable regulated retail electrical service. The Company has failed to demonstrate that new EV assets and infrastructure are necessary to provide that service.

A. The Make Ready Program

The Commission should reject the Company's proposed Make Ready program and the associated capital costs should be excluded from calculations for ratemaking purposes because it obligates captive electric service customers to subsidize the provision of an unregulated service, electric vehicle charging. Tr. 1316. Investments needed to provide an unregulated service to private groups should be paid for by the businesses or organization wanting to provide that unregulated service because those are the entities that stand to benefit from the investments in behind-the-meter EV charging infrastructure. Most ratepayers do not currently, and likely will not during 2023-2025 or even beyond that rate plan period, own an electric vehicle and thus will receive no direct benefit from the Make Ready program. Approving the Make Ready program would allow the Company to expand its business beyond regulated retail electrical service and into the unregulated private market for EV charging at the expense of ratepayers and to the detriment of competitors in the EV charging market who do not have access to ratepayer subsidized funding.

The Company may argue that its proposal to recover Make Ready program costs from captive ratepayers is consistent with the stipulation adopted by the Commission in the 2019 rate case. In the 2019 rate case, the Commission adopted a settlement that, in relevant part, permitted Georgia Power to recover costs from Make Ready spending. Tr. 1317. The amount the Company was allowed to recover, however, was only $6 million per year for plan years 2020 through 2022, the entirety of which was authorized to go towards "wire and transformer upgrades." *Id.*

The Make Ready program proposed by the Company in the current rate case, however, goes well beyond the scope of that settlement agreement, with 99% of the Company's spending going towards upgrades that would be on the "customer side" of the meter such as EV chargers. *Id.*

The unfairness of Georgia Power's proposal is exacerbated by the uncertainty over whether the public (who will be paying for the program under Georgia Power's proposal) will even have access to Make Ready – funded EV charging stations once the infrastructure has been built. The Company failed to respond to Staff's informal question on this issue. *Id.* at 76. Despite three rounds of hearings, the record contains no evidence that Make Ready charging stations will be required to be open to the public. Moreover, it appears the vast majority of the charging stations will be private, and not open to the ratepayers who would pay for the supporting assets.[5]

The Company contends that expenditures for the Make Ready program are necessary to prepare for the coming onslaught of electric vehicle transportation. Implementing the Make Ready program would essentially make the Company a top player in the unregulated market of EV transportation and charging services. But there is no competent record evidence indicating when this change will occur and no evidence as to whether a meaningful percentage of current ratepayers will drive an electric vehicle in the near future. The current rate case record has insufficient justification to burden ratepayers with substantially increased costs for behind-the-meter EV infrastructure that is not necessary for the provision of safe and reliable retail electric service, and which will not likely be used by, or benefit, the vast majority of ratepayers.

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[5] That the Company designated the Make Ready locations as trade secret illustrates the unfairness of the Company's proposal. Not only will customers be required to fund a program they won't benefit from, but they won't even be allowed to find out who is benefitting. If the Commission approves the Make Ready program, it should scrutinize carefully Georgia Power's assertion that the Make Ready locations meet the definition of trade secret.

B. EV Community Charging Stations

The Company seeks to recover $3 million per year of capital spending on infrastructure upgrades for the Community Charging program. Tr. 1324 These infrastructure upgrades include but are not limited to "EV chargers, wires, panels, conduit, transformers, and labor."[6] *Id.*

The Commission should reject Georgia Power's request for these additional capital investments in the Community Charging program because the Company has failed to show that the charging stations will generate enough revenue to cover O&M expense and depreciation, much less cover the return on capital and income taxes associated with the investment. Tr. 1325-26. As with the Make Ready program, the majority of ratepayers that will be funding the program will not receive any benefit from it. Tr. 1324. Moreover, the open, competitive, unregulated market is expected to provide a significant number of EV charging stations in the future. *Id.* Because the competitive market is expected to provide this service, Georgia Power's proposal for additional expenditures that would be funded by captive ratepayers is unnecessary to address whatever increase in EVs occurs. Georgia Power's program should be rejected because it is unfair to the majority of its customers, has not been shown to be necessary, and would put Georgia Power in an unfairly advantaged position vis-à-vis competitors in the EV charging market who do not have access to captive monopoly ratepayer funding for their comparable capital expenditures and EV charging station operating costs.

V. Stock-Based Compensation

Georgia Power should not be permitted to recover stock-based compensation from ratepayers because the compensation aligns the interest of the recipient with the interests of shareholders, not with ratepayers. This form of compensation is paid to high-level Georgia

[6] Quoting from STF-LA-6-19.

Power executives. Tr. 4027. The compensation is directly tied to the performance of Southern Company stock. Tr. 4028. As a result, if the stock does better, the executive receiving stock-based compensation does better. The recipient is thus put in a similar position to a shareholder, and is incentivized to act in a way that benefits shareholders, not customers. Therefore, to the extent the Company, like other investor-owned companies in the regulated public utility business, offers this incentive to its high-level executives, shareholders, and not ratepayers should fund the incentive. And that is a key point, Staff is not opposed to the Company offering stock-based compensation. But the compensation should be paid for by the group who benefits from the incentive, and that is the shareholders.

Georgia Power's response is that ratepayers should pay because the interests of ratepayers and the Company are always aligned. Tr. 4029. This is demonstrably not the case. Let's take return on equity as an example. If the Company earns a higher return on equity, common stockholders have a better the opportunity for higher total returns. The shareholders are the primary ones that will benefit from having higher earnings per share and having a higher total return on their common stock investment. But ratepayers have to pay more as a result of the higher return on equity. Put simply, the higher the return on equity, the higher probability that shareholders will make more money and ratepayers pay more money. The interests of shareholders and ratepayers are largely opposed in this situation. And the Company's proposal sticks ratepayers with a double-whammy. Not only do ratepayers have to pay more in the form of higher rates as a result of the high ROE awarded, but on top of that they would have to pay the incentive to Georgia Power's most generously compensated executives as a result of their success in having the Commission award the high authorized return. This outcome is even more galling considering the wealth disparity between the high-level executives receiving this incentive compensation and the Company's ratepayers, many of whom struggle to pay their power bills. The Company's argument that ratepayers benefit from a substantially above industry average ROE just as shareholders do because everyone benefits from a financially strong utility is myopic. First, it is telling that the same Company witness who claimed that the interests of the Company and its customers are always aligned could not name a single time in which a party representing customers proposed a higher ROE than the Company in a rate case. Tr. 4029. If the interests were always aligned, as Georgia Power maintains, then one would expect that occasionally a customer group may recommend an ROE that was as high or higher than the ROE recommended by the Company. But that hasn't happened, not in this case and not in any case the Georgia Power witness could remember. Second, Georgia Power can remain financially strong, even if the Commission reduces the ROE the Company requests. Thus, the fact that, all things being equal, a financially strong utility is better for its customers does not mean that the best interests of ratepayers are served by Georgia Power being awarded the ROE it requests.

For these reasons, Georgia Power's argument that shareholder-based compensation should be treated the same as any other part of the executive's overall compensation is without merit. Not all forms of compensation are the same. To the extent the Company believes that a bonus program with higher compensation is necessary to attract executives, Staff is not opposed to the Company offering incentive programs as part of that compensation package. If the Company wants ratepayers to pay for the incentive, however, the Company could have chosen an incentive mechanism that used metrics, and encouraged outcomes, that benefited ratepayers. If it had done that, it may have been reasonable to ask ratepayers to pay for it. But, it chose not to do so.

VI. RNR Monthly-Netting

Staff recommends that the Commission remove the cap on Renewable and Non-Renewable ("RNR") Monthly-Netting. At this stage in the market, there is no need to artificially constrain the amount of roof top solar in Georgia. In the event that the Commission decides that it would prefer instantaneous net metering, Staff recommends that the rate the Company pays for excess generation be set at the retail rate less 3 cents per kWh beginning January 1, 2023. This approach for setting an "export rate" is similar to the recent net metering compensation method approved by the Michigan Public Service Commission for DTE Energy (formerly Detroit Edison). Staff understands that this issue is a policy decision for the Commission and therefore recommends that customers continue to have the option of monthly-netting due to the low amount of revenue erosion alleged by Georgia Power.

As part of the July 29, 2022 Georgia Power Integrated Resource Plan ("IRP") Order, the Commission ordered Staff and Georgia Power to address the structure and pricing of the RNR tariff in the Company's 2022 Rate Case. In its Supplemental Direct Testimony, the Company simply conducted an analysis of the revenue erosion it confronts as a result of: (a) customers reducing their energy requirements simply due to supplemental self-generation; and (b) the netting value associated with RNR Monthly Netting. On page 12 of the Company's Supplemental Direct Testimony, Legg provides Figure 3 showing the components of his calculated average revenue erosion of $826 per customer per year.

Legg's analysis is based on a sample of 1,110 residential monthly netting customers. While Staff has no objection to the use of a sample, Staff believes the assumptions used by the Company to estimate the lost revenue from RNR customers overinflate the bill savings that RNR customers receive primarily by overestimating the production by customer facilities. However, more concerning is the lack of validation of the Company's methodology using historical data for estimating RNR customer solar production and the customer's consumption before the installation of their solar system. The Company has not provided or utilized any historical data from existing RNR customers in order to validate the method it used to estimate RNR lost revenue. Without a benchmark to historical data, Staff cannot ensure the accuracy of the Company's estimates of customer usage prior to solar installation, or the appropriateness of the chosen customer load profiles for representing solar customers.

Staff disagrees with the Company's assessment that there is significant cost shifting from the installation of behind the meter ("BTM") solar. Company Witnesses' Evans and Legg conducted a revenue erosion analysis showing that due to self-generation RNR Monthly Netting customers purchase less electricity from the Company. The Company labels this as cost shifting but it should be more appropriately identified as revenue erosion. RNR Monthly Netting customers still pay a basic service cost plus all applicable riders. Additionally, as shown in Staff's Supplemental Direct Testimony, RNR customers pay for some amount of kWh used in about 90% of all months. It is worth noting that the zero net usage months tend to occur on the lower cost shoulder months such as March, April, May and October. Also, over 90% of RNR Monthly Netting customers have four or fewer zero kWh usage months further demonstrating that these customers pay the Company for services the majority of the time.

According to the Company's analysis they found that an average RNR Monthly Netting customer receives $287 more than an Instantaneous Netting customers per year. If applied to the 5,000 monthly netting customers, the total revenue erosion from monthly netting is about $1.4 million dollars. When compared to the total residential revenue of $2.9 billion dollars, $1.4 million is 0.048% of total revenue and by any measure de minimis. Staff does not find this amount significant and should not be a determining factor in the Commission's determination of whether to continue RNR Monthly Netting or in the setting of a rate for excess solar compensation.

Staff conducted a study based on the Company's class cost of service study in which the residential direct and indirect distribution costs (rate base and expenses) were subtracted from the total bundled revenues such that the allocated amounts for only generation and transmission were considered. This study resulted in a possible monthly netting compensation rate of 6.99¢ per kWh at current rates and the rate per kWh should be updated as new rates are approved. For illustrative purposes, if the Commission authorized half of the Company requested base rate increase this rate would increase to 7.63¢. The details of this study were provided in Staff's Supplemental Testimony Exhibit __ BCW-12. Because electricity takes the path of least resistance, any excess generation supplied to the grid will remain within Georgia Power's distribution system. As a result, this supplied energy does not rely upon the Company's transmission system, and can therefore, be thought of as avoiding additional transmission capacity and costs in the long-term.

The valuation of excess generation supplied to the grid by RNR customers is a policy decision for the Commission, and as such, Staff provided a range of possible of values (at current rates) per kWh for the excess generation due to residential monthly netting:

Unbundled Generation plus Transmission		6.99¢
GPC Owned Solar Revenue Requirement		7.35¢ to 8.34¢
Full Retail Volumetric Rate		
Non-Summer		9.01¢
Summer		12.94¢
Annual		10.22¢

Staff also conducted research regarding what other states have done to value solar exports from BTM systems. Staff disagrees with the characterization by Company Witness Dr. Gattie that other states are dramatically shifting from monthly netting as thirty-three states have full retail monthly netting as their default payment for BTM solar (Supplemental Direct Testimony p. 7). The states that have addressed export rates recently have a much higher penetration rate, often at least twenty-five times more installed capacity, than Georgia. These states all have designed rates that compensate customers at significantly higher rates than the marginal avoided cost rate as determined by the RCB Framework and offered through instantaneous netting.

Staff's preferred approach for determining the export value for solar exports by RNR customers is that the Commission adopt an export rate approach similar to the recent net metering compensation method approved by the Michigan Public Service Commission for DTE Energy (formerly Detroit Edison). This value is determined by using the Company's embedded costs instead of a using a marginal cost approach such as the RCB Framework.

The RNR tariff was originally offered with only an instantaneous netting compensation option to satisfy the requirements of the Georgia Cogeneration and Distributed Generation Act of 2001 ("Cogen Act"). This option, which is now referred to as RNR-Instantaneous Netting, is available to all eligible customers on a first come, first served basis until the cumulative generating capacity of all renewable sources equals to 0.2 percent (0.2%) of the Company's annual peak demand in the previous year, as dictated by the Cogen Act.

The Company reported that, at the beginning of the year, the cumulative generating capacity of RNR Instantaneous customers was approximately 2.2 MW, or only 0.014% of the Company's 2021 peak demand of 16,213 MW (Company's Response to STF-DEA-1-4 and provided as Staff Exhibit __ BCW-7). However, since the cap for RNR Monthly Netting was reached in mid-2021, more than 40 MW of additional capacity have applied for RNR Instantaneous Netting according to Company's Response to STF-TAI-8-19 and provided as Staff Exhibit __ BCW-8.

If all of these solar systems proceed to installation, this amount might exceed the 0.2% cumulative generating capacity as stated in the Cogen Act. Based on these current applications and the rate of new applications, Staff expects that the cumulative generating capacity of the RNR Instantaneous customers will exceed the 0.2% of the Company's prior year peak demand very soon.

Unlike monthly netting where the Company is not purchasing the customer's excess generation, the Company's obligation to purchase excess generation may end when the 0.2% of the Company's prior year annual peak demand is reached. This could mean that customers who install a rooftop system after the limit is reached would receive no value for their excess energy.

As described in Staff's testimony, the rooftop solar industry in Georgia has lagged behind almost every other state. Georgia ranks in the 40's for the total number of BTM installations according to a SEIA/Wood Mackenzie study and is ranked dead last in regulatory environment for rooftop solar according to industry reports cited in intervener testimony.

Staff does not recommend approval of the Company's proposal to require RNR solar customers to enroll in a three-part rate that includes a demand charge as recommended by Company Witnesses Evans and Legg (Supplemental Direct Testimony p. 14). Due to its structure, with a high demand charge, and extremely low off-peak energy price, TOU-RD is not well-suited for RNR customers. Under the current TOU-RD rate structure, there are only about 511 on-peak hours in the year and about 8,249 off-peak hours during the year.[7] First, consider

[7] The on-peak period is the four months of June-September, weekdays excluding holidays for the hours of 2:00 pm-

the scenario of the continuation of monthly netting. The customer would only receive a netting value of about 1.0¢ per kWh, less than half of the current solar avoided cost rate of 2.68¢ per kWh during all off-peak daylight hours. Second, consider the scenario of continuing instantaneous netting. During off-peak hours, the customer would pay about 1.0¢ per kWh for delivered energy but receive a netting value of about 2.68¢ per kWh for excess energy supplied to the grid.

VII. Rate Design

Staff's recommendation that the R rate become the default tariff for all residential premises regardless of when the premise was constructed is better for customers in terms of both price signals and bill impact. Staff's analysis of customers that had previously defaulted to TOU-RD showed that those customers, on average, paid $200 more per year than if they had been on the R rate. Staff does not support the Company recommendation that the Residential Service tariff be unavailable to new premises after January 1, 2023.

Company Witness Legg stated in his prefiled direct testimony that, "the Company's proposal is the logical next step in the Company's ongoing efforts to encourage residential customers to move toward more modern rate structures. As initially discussed in the Company's 2019 base rate case, utilities across the country are proactively moving away from more antiquated volumetric rate designs (such as the R rate) and toward more modern rate designs that send price signals that more appropriately reflect the cost of service."
(Barber/Deitchman/Watkins at 69).

As Staff discussed in their prefiled Direct testimony there is not a single investor-owned utility ("IOU") in the country that has mandatory residential demand charge rates. In STF-PIA-

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7:00 pm

2-5, the Company was asked to "Please provide any research or analysis of the Company related to demand charges in other jurisdictions." The Company's responded by stating in part that, "the Company does not have an internally developed analysis or summary of these programs." (*Id. At 70)*.

Staff recommends that the R rate become the default tariff for all residential premises regardless of when the premise was constructed. Staff's recommendation is based on the above sited analysis that indicated that customers that had previously defaulted to TOU-RD showed that those customers, on average, paid $200 more per year than if they had been on the R rate.

VIII. Conclusion

For the foregoing reasons, Public Interest Advocacy Staff urges the Commission to issue an order that adopts the positions contained herein and in the testimony submitted by Staff.

Respectfully submitted, this 8th day of December, 2022.

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BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of	)	
	)	
	)	**Docket No. 44280**
Georgia Power Company's	)	
2022 Rate Case	)	

CERTIFICATE OF SERVICE

I hereby certify that the foregoing Post-Hearing Brief of the Public Interest Advocacy Staff in the above-referenced docket was filed with the Commission's Executive Secretary, an electronic copy of same was served upon all parties and persons listed below via electronic mail, or unless otherwise indicated, as follows:

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So certified, this 8th day of December 2022.

/s/Ann McCullough

Ann McCullough
Public Service Commission Staff

SMITH/TROKEY DEMONSTRATIVE

EXHIBIT NO. __(2)

Based on Exhibit__(RS/RT-2), pages 5-8

and a High Level Summary of Revenue

Requirement Impacts by Staff

Witness Panels

Georgia Power Company
Revenue Requirement Reconciliation Summary
Retail Electric Amounts
Test Year Ended July 31, 2023
(Thousands of Dollars)

Line No.	Staff Witness	Staff Estimated Revenue Requirement Impact Test Year (A)	Staff Estimated Revenue Requirement Impact 2023 (B)	Staff Estimated Revenue Requirement Impact 2024 (C)	Staff Estimated Revenue Requirement Impact 2025 (D)
1	Michael Gorman - Return on Equity and Capital Structure	$ (277,265)	$ (292,322)	$(419,429)	$ (442,745)
2	Paul Alvarez, Dennis Stevens and Raj Rana - T&D Capital Spending and DERMS	$ -	$ (30,517)	$ (91,380)	$ (159,366)
3	Steve Baron and Leah Wellborn - Forecasted Revenues at Current Rates	$ (5,999)	$ (5,705)	$ (4,874)	$ (7,763)
4	Ralph Smith and Robert Trokey - Rate Base and Net Operating Income	$ (20,944)	$ (58,724)	$ (41,499)	$ (74,627)
5	Dante Mugrace - O&M Expense	$ (199,861)	$ (156,482)	$(145,367)	$ (179,790)
6	Lance Kaufman - Depreciation Expense - New Depreciation Rates	$ (30,033)	$ (51,698)	$ (50,008)	$ (47,074)
7	GRCF Difference	$ (1)	$ -	$ -	$ -
8	Staff Revenue Requirement Adjustments	$ (534,102)	$ (595,448)	$(752,558)	$ (911,364)
9	Company Requested Base Rate Revenues, Not Including Levelization	$ 447,521	$ 584,204	$ 905,447	$ 1,299,024
10	Reconciled Revenue Requirement Deficiency/(Excess)	$ (86,580)	$ (11,244)	$ 152,889	$ 387,659
11	Revenue Requirement Calculated on Schedule A of Exhibit__(RS/RT-2)	$ (86,581)	$ (11,244)	$ 152,889	$ 387,659
12	Difference	$ 0	$ 0	$ (0)	$ 0

Notes and Source

Col. A: see page 2
Col. B: see page 3
Col. C: see page 4
Col. D: see page 5

Georgia Power Company
Revenue Requirement Reconciliation
Retail Electric Amounts
Test Year Ended July 31, 2023
(Thousands of Dollars)

Line No.	Description	Schedule Reference	Staff Witness	Component (A)	Net Operating Income Amount Sch C.1 (B)	Rate Base Adjustment Sch B.1 (C)	Staff Rate Base Multiplier (D)	Staff Multiplier (E)	Staff Estimated Revenue Requirement Impact (F)
1		D	M. Gorman	ROR Difference				-0.8613%	
2	**Rate Base**	A-1	R. Smith/R. Trokey	GRCF	x			x 1.340378	
3	Rate Base per Company's Filing	B	M. Gorman			$ 24,018,127 x		-1.154%	$ (277,265)
	Estimated Revenue Requirement Effect of Staff NOI and Rate Base Adjustments	Staff Adjustment		Pre-Tax Operating Income Amount				Staff GRCF NOI Multiplier Sch A-1	
4	Company Supplemental - Rate Base Adjustments	E-1	R. Smith/R. Trokey	$ -	$ -	$ 9,524	9.17%	1.340378	$ 873
5	Company Supplemental - Operating Income Adjustments	E-2	R. Smith/R. Trokey	$ (11,296)	$ (8,401)		9.17%	1.340378	$ 11,260
6	Forecasted Revenues	E-3	S. Baron/L. Wellborn	$ 5,991	$ 4,475		9.17%	1.340378	$ (5,999)
7	Stock-Based Compensation	E-4	R. Smith/R. Trokey	$ 29,172	$ 21,793		9.17%	1.340378	$ (29,211)
8	Payroll Tax Expense	E-5	R. Smith/R. Trokey	$ 2,232	$ 1,667		9.17%	1.340378	$ (2,234)
9	Energy Direct Premium Packages	E-6	R. Smith/R. Trokey	$ 1,165	$ 870		9.17%	1.340378	$ (1,166)
10	Executive Financial Planning	E-7	R. Smith/R. Trokey	$ 467	$ 349		9.17%	1.340378	$ (468)
11	Interest Synchronization Adjustment	E-8	R. Smith/R. Trokey	$ -	$ (598)		9.17%	1.340378	$ 802
12	O&M Scrap Sales Proceeds	E-9	R. Smith/R. Trokey	$ 1,216	$ 908		9.17%	1.340378	$ (1,217)
13	Cash Working Capital	E-10	R. Smith/R. Trokey	$ -	$ -	$ (4,000)	9.17%	1.340378	$ (367)
14	Wireless Co-Location Revenues	E-11	R. Smith/R. Trokey	$ 404	$ 302		9.17%	1.340378	$ (404)
15	Depreciation Expense and Accumulated Depreciation - New Depreciation Rates	E-12	L. Kaufman/R. Smith/R. Trokey	$ 31,434	$ 23,483	$ 15,741	9.17%	1.340378	$ (30,033)
16	Electric Vehicle Make Ready Program	E-13	R. Smith/R. Trokey	$ -	$ -		9.17%	1.340378	$ -
17	Electric Vehicle Community Charging Stations	E-14	R. Smith/R. Trokey	$ -	$ -		9.17%	1.340378	$ -
18	O&M Expense - Electric Vehicle Infrastructure	E-15	D. Mugrace	$ -	$ -		9.17%	1.340378	$ -
19	O&M Expense - Transmission	E-16	D. Mugrace	$ 10,679	$ 7,978		9.17%	1.340378	$ (10,693)
20	O&M Expense - Distribution	E-17	D. Mugrace	$ 23,593	$ 17,625		9.17%	1.340378	$ (23,624)
21	O&M Expense - Customer Accounting	E-18	D. Mugrace	$ 16	$ 12		9.17%	1.340378	$ (16)
22	O&M Expense - Demonstration & Selling Expenses	E-19	D. Mugrace	$ 1,187	$ 887		9.17%	1.340378	$ (1,189)
23	O&M Expense - Administrative & General Salaries	E-20	D. Mugrace	$ 253	$ 189		9.17%	1.340378	$ (253)
24	O&M Expense - Office Supplies and Expense	E-21	D. Mugrace	$ 3,124	$ 2,334		9.17%	1.340378	$ (3,128)
25	O&M Expense - Outside Services Employed	E-22	D. Mugrace	$ 7,090	$ 5,297		9.17%	1.340378	$ (7,100)
26	O&M Expense - Injuries and Damages	E-23	D. Mugrace	$ 1,640	$ 1,225		9.17%	1.340378	$ (1,642)
27	O&M Expense - Employee Pensions and Benefits	E-24	D. Mugrace	$ 13,658	$ 10,203		9.17%	1.340378	$ (13,676)
28	O&M Expense - Customer Service and Information	E-25	D. Mugrace	$ 17,000	$ 12,700		9.17%	1.340378	$ (17,023)
29	O&M Expense - Miscellaneous General and Advertising	E-26	D. Mugrace	$ 5,935	$ 4,434		9.17%	1.340378	$ (5,943)
30	O&M Expense - Maintenance of General Plant	E-27	D. Mugrace	$ 1,821	$ 1,360		9.17%	1.340378	$ (1,823)
31	O&M Expense - Adjustment for Inflation	E-28	D. Mugrace	$ -	$ -		9.17%	1.340378	$ -
32	Labor O&M Expense - Vacancy Rate, Employee Levels, Performance Pay Plan and Overtime	E-29	D. Mugrace	$ 113,600	$ 84,864		9.17%	1.340378	$ (113,750)
33	Transmission Plant Investment	E-30	P. Alvarez/D. Stevens/R. Rana			$ -	9.17%	1.340378	$ -
34	Distribution Plant Investment	E-31	P. Alvarez/D. Stevens/R. Rana			$ -	9.17%	1.340378	$ -
35	Distributed Energy Resource Management System (DERMS)	E-32	P. Alvarez/D. Stevens/R. Rana			$ -	9.17%	1.340378	$ -
36	Transmission Plant - Depreciation Expense and Accumulated Depreciation	E-33	R. Smith/R. Trokey			$ -	9.17%	1.340378	$ -
37	Distribution Plant - Depreciation Expense and Accumulated Depreciation	E-34	R. Smith/R. Trokey			$ -	9.17%	1.340378	$ -
38	Distributed Energy Resource Management System (DERMS) - Amortization and Accumulated Amortizat	E-35	R. Smith/R. Trokey			$ -	9.17%	1.340378	$ -
39	Depreciation Expense - Depreciation Rates Correction for Ft Benning and Ft Gordon	E-36	R. Smith/R. Trokey	$ (1,186)	$ (886)	$ -	9.17%	1.340378	$ 1,188
40	Property Tax Expense	E-37	R. Smith/R. Trokey	$ -	$ -	$ -	9.17%	1.340378	$ -
41	Income Tax Credits Related to the Inflation Reduction Act	E-38	R. Smith/R. Trokey	$ -	$ -	$ -	9.17%	1.340378	$ -
42	Sum of Staff's Adjustments			$ 259,194	$ 193,069	$ 21,265			
43	Company Proposed Net Operating Income and Rate Base				$ 1,515,820	$ 24,018,127			
44	**Staff Adjusted Net Operating Income and Staff Adjusted Rate Base**	C			$ 1,708,889	$ 24,039,392			
	Gross Revenue Conversion Factor Difference:								
45	Per Staff	A-1						1.340378	
46	Per Company	A-1						1.340381	
47	Difference							-0.000003	
48	Company Adjusted NOI Deficiency	A						$ 333,876	
49	GRCF Difference								$ (1)
50	Staff REVENUE REQUIREMENT ADJUSTMENTS ABOVE								$ (534,102)
51	Company Requested Base Rate Revenues, Not Including Levelization	A							$ 447,521
52	Reconciled Revenue Requirement								$ (86,580)
53	Revenue Requirement Calculated on Schedule A	A							$ (86,581)
54	Unidentified Difference (rounding)								$ 0

Notes and Source
Pre-tax return computed using Gross Revenue Conversion Factor

	D	Rate of Return	6.84%
Effect of Staff Adjustments to Rate Base	A-1	GRCF	x 1.340378
Staff Rate Base Multiplier			9.17%

Georgia Power Company
Revenue Requirement Reconciliation
Retail Electric Amounts
Calendar Year 2023
(Thousands of Dollars)

Line No.	Description	Schedule Reference	Staff Witness	Component (A)	Net Operating Income Amount Sch C.1 (B)	Rate Base Adjustment Sch B.1 (C)	Staff Rate Base Multiplier (D)	Staff Multiplier (E)	Staff Estimated Revenue Requirement Impact (F)
1		D	M. Gorman	ROR Difference				-0.8734%	
2	**Rate Base**	A-1	R. Smith/R. Trokey	GRCF	x			x 1.340449	
3	Rate Base per Company's Filing	B	M. Gorman			$ 24,968,611 x		-1.171%	$ (292,322)
	Estimated Revenue Requirement Effect of Staff NOI and Rate Base Adjustments	Staff Adjustment		Pre-Tax Operating Income Amount				Staff GRCF NOI Multiplier Sch. A-1	
4	Company Supplemental - Rate Base Adjustments	E-1	R. Smith/R. Trokey	$ -	$ -	$ 16,781	9.17%	1.340449	$ 1,539
5	Company Supplemental - Operating Income Adjustments	E-2	R. Smith/R. Trokey	$ (26,432)	$ (19,680)		9.17%	1.340449	$ 26,380
6	Forecasted Revenues	E-3	S. Baron/L. Wellborn	$ 5,697	$ 4,256		9.17%	1.340449	$ (5,705)
7	Stock-Based Compensation	E-4	R. Smith/R. Trokey	$ 29,063	$ 21,711		9.17%	1.340449	$ (29,102)
8	Payroll Tax Expense	E-5	R. Smith/R. Trokey	$ 2,223	$ 1,661		9.17%	1.340449	$ (2,226)
9	Energy Direct Premium Packages	E-6	R. Smith/R. Trokey	$ 1,176	$ 878		9.17%	1.340449	$ (1,177)
10	Executive Financial Planning	E-7	R. Smith/R. Trokey	$ 467	$ 349		9.17%	1.340449	$ (468)
11	Interest Synchronization Adjustment	E-8	R. Smith/R. Trokey	$ -	$ (1,420)		9.17%	1.340449	$ 1,903
12	O&M Scrap Sales Proceeds	E-9	R. Smith/R. Trokey	$ 1,216	$ 908		9.17%	1.340449	$ (1,217)
13	Cash Working Capital	E-10	R. Smith/R. Trokey			$ (1,000)	9.17%	1.340449	$ (92)
14	Wireless Co-Location Revenues	E-11	R. Smith/R. Trokey	$ 433	$ 324		9.17%	1.340449	$ (434)
15	Depreciation Expense and Accumulated Depreciation - New Depreciation Rates	E-12	L. Kaufman/R. Smith/R. Trokey	$ 54,117	$ 40,428	$ 27,206	9.17%	1.340449	$ (51,698)
16	Electric Vehicle Make Ready Program	E-13	R. Smith/R. Trokey	$ 391	$ 292	$ (13,304)	9.17%	1.340449	$ (1,611)
17	Electric Vehicle Community Charging Stations	E-14	R. Smith/R. Trokey	$ 43	$ 32	$ (1,478)	9.17%	1.340449	$ (179)
18	O&M Expense - Electric Vehicle Infrastructure	E-15	D. Mugrace	$ 2,505	$ 1,871		9.17%	1.340449	$ (2,507)
19	O&M Expense - Transmission	E-16	D. Mugrace	$ 4,178	$ 3,121		9.17%	1.340449	$ (4,183)
20	O&M Expense - Distribution	E-17	D. Mugrace	$ (5,402)	$ (4,036)		9.17%	1.340449	$ 5,410
21	O&M Expense - Customer Accounting	E-18	D. Mugrace	$ (1,303)	$ (973)		9.17%	1.340449	$ 1,305
22	O&M Expense - Demonstration & Selling Expenses	E-19	D. Mugrace	$ 1,215	$ 908		9.17%	1.340449	$ (1,217)
23	O&M Expense - Administrative & General Salaries	E-20	D. Mugrace	$ 183	$ 137		9.17%	1.340449	$ (184)
24	O&M Expense - Office Supplies and Expense	E-21	D. Mugrace	$ -	$ -		9.17%	1.340449	$ -
25	O&M Expense - Outside Services Employed	E-22	D. Mugrace	$ (940)	$ (702)		9.17%	1.340449	$ 941
26	O&M Expense - Injuries and Damages	E-23	D. Mugrace	$ (622)	$ (465)		9.17%	1.340449	$ 623
27	O&M Expense - Employee Pensions and Benefits	E-24	D. Mugrace	$ 13,498	$ 10,084		9.17%	1.340449	$ (13,517)
28	O&M Expense - Customer Service and Information	E-25	D. Mugrace	$ 20,000	$ 14,941		9.17%	1.340449	$ (20,028)
29	O&M Expense - Miscellaneous General and Advertising	E-26	D. Mugrace	$ 6,123	$ 4,574		9.17%	1.340449	$ (6,131)
30	O&M Expense - Maintenance of General Plant	E-27	D. Mugrace	$ -	$ -		9.17%	1.340449	$ -
31	O&M Expense - Adjustment for Inflation	E-28	D. Mugrace	$ 15,437	$ 11,532		9.17%	1.340449	$ (15,458)
32	Labor O&M Expense - Vacancy Rate, Employee Levels, Performance Pay Plan and Overtime	E-29	D. Mugrace	$ 101,396	$ 75,747		9.17%	1.340449	$ (101,536)
33	Transmission Plant Investment	E-30	P. Alvarez/D. Stevens/R. Rana			$ (163,745)	9.17%	1.340449	$ (15,013)
34	Distribution Plant Investment	E-31	P. Alvarez/D. Stevens/R. Rana			$ (164,124)	9.17%	1.340449	$ (15,048)
35	Distributed Energy Resource Management System (DERMS)	E-32	P. Alvarez/D. Stevens/R. Rana			$ (4,974)	9.17%	1.340449	$ (456)
36	Transmission Plant - Depreciation Expense and Accumulated Depreciation	E-33	R. Smith/R. Trokey	$ 3,997	$ 2,986	$ 1,998	9.17%	1.340449	$ (3,820)
37	Distribution Plant - Depreciation Expense and Accumulated Depreciation	E-34	R. Smith/R. Trokey	$ 4,755	$ 3,552	$ 2,378	9.17%	1.340449	$ (4,544)
38	Distributed Energy Resource Management System (DERMS) - Amortization and Accumulated Amortization	E-35	R. Smith/R. Trokey	$ 995	$ 743	$ 497	9.17%	1.340449	$ (950)
39	Depreciation Expense - Depreciation Rates Correction for Ft Benning and Ft Gordon	E-36	R. Smith/R. Trokey	$ (2,033)	$ (1,519)	$ -	9.17%	1.340449	$ 2,036
40	Property Tax Expense	E-37	R. Smith/R. Trokey	$ 2,266	$ 1,693	$ -	9.17%	1.340449	$ (2,269)
41	Income Tax Credits Related to the Inflation Reduction Act	E-38	R. Smith/R. Trokey	$ -	$ 31,700	$ -	9.17%	1.340449	$ (42,492)
42	Sum of Staff's Adjustments			$ 234,643	$ 205,634	$ (299,766)			
43	Company Proposed Net Operating Income and Rate Base				$ 1,490,104	$ 24,968,611			
44	**Staff Adjusted Net Operating Income and Staff Adjusted Rate Base**	C			$ 1,695,738	$ 24,668,845			
	Gross Revenue Conversion Factor Difference:								
45	Per Staff	A-1						1.340449	
46	Per Company	A-1						1.340449	
47	Difference							0.000000	
48	Company Adjusted NOI Deficiency	A						$ 262,390	
49	GRCF Difference								$ -
50	Staff REVENUE REQUIREMENT ADJUSTMENTS ABOVE								$ (595,448)
51	Company Requested Base Rate Revenues, Not Including Levelization	A							$ 584,204
52	Reconciled Revenue Requirement								$ (11,244)
53	Revenue Requirement Calculated on Schedule A	A							$ (11,244)
54	Unidentified Difference (rounding)								$ 0

Notes and Source
Pre-tax return computed using Gross Revenue Conversion Factor

	D	Rate of Return		6.84%
Effect of Staff Adjustments to Rate Base	A-1	GRCF	x	1.340449
Staff Rate Base Multiplier				9.17%

Georgia Power Company
Revenue Requirement Reconciliation
Retail Electric Amounts
Calendar Year 2024
(Thousands of Dollars)

Line No.	Description	Schedule Reference	Staff Witness	Component (A)	Net Operating Income Amount Sch C.1 (B)	Rate Base Adjustment Sch B.1 (C)	Staff Rate Base Multiplier (D)	Staff Multiplier (E)	Staff Estimated Revenue Requirement Impact (F)
1		D	M. Gorman	ROR Difference				-1.1654%	
2	**Rate Base**	A-1	R. Smith/R. Trokey	GRCF	x			x 1.340558	
3	Rate Base per Company's Filing	B	M. Gorman			$ 26,847,043 x		-1.562%	$ (419,429)
	Estimated Revenue Requirement Effect of Staff NOI and Rate Base Adjustments	Staff Adjustment		Pre-Tax Operating Income Amount				Staff GRCF NOI Multiplier Sch. A-1	
4	Company Supplemental - Rate Base Adjustments	E-1	R. Smith/R. Trokey	$ -	$ -	$ 19,352	8.81%	1.340558	$ 1,704
5	Company Supplemental - Operating Income Adjustments	E-2	R. Smith/R. Trokey	$ (40,775)	$ (30,384)		8.81%	1.340558	$ 40,731
6	Forecasted Revenues	E-3	S. Baron/L. Wellborn	$ 4,867	$ 3,636		8.81%	1.340558	$ (4,874)
7	Stock-Based Compensation	E-4	R. Smith/R. Trokey	$ 26,933	$ 20,120		8.81%	1.340558	$ (26,971)
8	Payroll Tax Expense	E-5	R. Smith/R. Trokey	$ 2,061	$ 1,540		8.81%	1.340558	$ (2,064)
9	Energy Direct Premium Packages	E-6	R. Smith/R. Trokey	$ 1,209	$ 903		8.81%	1.340558	$ (1,210)
10	Executive Financial Planning	E-7	R. Smith/R. Trokey	$ 466	$ 348		8.81%	1.340558	$ (467)
11	Interest Synchronization Adjustment	E-8	R. Smith/R. Trokey	$ -	$ 7,627		8.81%	1.340558	$ (10,224)
12	O&M Scrap Sales Proceeds	E-9	R. Smith/R. Trokey	$ 1,216	$ 908		8.81%	1.340558	$ (1,217)
13	Cash Working Capital	E-10	R. Smith/R. Trokey	$ -	$ -	$ (2,200)	8.81%	1.340558	$ (194)
14	Wireless Co-Location Revenues	E-11	R. Smith/R. Trokey	$ 520	$ 388		8.81%	1.340558	$ (521)
15	Depreciation Expense and Accumulated Depreciation - New Depreciation Rates	E-12	L. Kaufman/R. Smith/R. Trokey	$ 57,236	$ 42,758	$ 83,023	8.81%	1.340558	$ (50,008)
16	Electric Vehicle Make Ready Program	E-13	R. Smith/R. Trokey	$ 1,173	$ 876	$ (39,522)	8.81%	1.340558	$ (4,656)
17	Electric Vehicle Community Charging Stations	E-14	R. Smith/R. Trokey	$ 130	$ 97	$ (4,391)	8.81%	1.340558	$ (517)
18	O&M Expense - Electric Vehicle Infrastructure	E-15	D. Mugrace	$ 2,891	$ 2,160		8.81%	1.340558	$ (2,895)
19	O&M Expense - Transmission	E-16	D. Mugrace	$ 3,218	$ 2,404		8.81%	1.340558	$ (3,223)
20	O&M Expense - Distribution	E-17	D. Mugrace	$ 328	$ 245		8.81%	1.340558	$ (328)
21	O&M Expense - Customer Accounting	E-18	D. Mugrace	$ 5,109	$ 3,817		8.81%	1.340558	$ (5,116)
22	O&M Expense - Demonstration & Selling Expenses	E-19	D. Mugrace	$ 1,217	$ 909		8.81%	1.340558	$ (1,219)
23	O&M Expense - Administrative & General Salaries	E-20	D. Mugrace	$ 83	$ 62		8.81%	1.340558	$ (83)
24	O&M Expense - Office Supplies and Expense	E-21	D. Mugrace	$ -	$ -		8.81%	1.340558	$ -
25	O&M Expense - Outside Services Employed	E-22	D. Mugrace	$ (2,319)	$ (1,732)		8.81%	1.340558	$ 2,322
26	O&M Expense - Injuries and Damages	E-23	D. Mugrace	$ 1,285	$ 960		8.81%	1.340558	$ (1,287)
27	O&M Expense - Employee Pensions and Benefits	E-24	D. Mugrace	$ 13,216	$ 9,873		8.81%	1.340558	$ (13,235)
28	O&M Expense - Customer Service and Information	E-25	D. Mugrace	$ 16,000	$ 11,953		8.81%	1.340558	$ (16,024)
29	O&M Expense - Miscellaneous General and Advertising	E-26	D. Mugrace	$ 4,236	$ 3,164		8.81%	1.340558	$ (4,242)
30	O&M Expense - Maintenance of General Plant	E-27	D. Mugrace	$ -	$ -		8.81%	1.340558	$ -
31	O&M Expense - Adjustment for Inflation	E-28	D. Mugrace	$ 27,334	$ 20,420		8.81%	1.340558	$ (27,374)
32	Labor O&M Expense - Vacancy Rate, Employee Levels, Performance Pay Plan and Overtime	E-29	D. Mugrace	$ 72,557	$ 54,203		8.81%	1.340558	$ (72,662)
33	Transmission Plant Investment	E-30	P. Alvarez/D. Stevens/R. Rana	$ -	$ -	$ (484,508)	8.81%	1.340558	$ (42,673)
34	Distribution Plant Investment	E-31	P. Alvarez/D. Stevens/R. Rana	$ -	$ -	$ (523,165)	8.81%	1.340558	$ (46,078)
35	Distributed Energy Resource Management System (DERMS)	E-32	P. Alvarez/D. Stevens/R. Rana	$ -	$ -	$ (29,858)	8.81%	1.340558	$ (2,630)
36	Transmission Plant - Depreciation Expense and Accumulated Depreciation	E-33	R. Smith/R. Trokey	$ 11,831	$ 8,838	$ 9,910	8.81%	1.340558	$ (10,975)
37	Distribution Plant - Depreciation Expense and Accumulated Depreciation	E-34	R. Smith/R. Trokey	$ 15,159	$ 11,325	$ 12,335	8.81%	1.340558	$ (14,095)
38	Distributed Energy Resource Management System (DERMS) - Amortization and Accumulated Amortization	E-35	R. Smith/R. Trokey	$ 5,972	$ 4,461	$ 3,972	8.81%	1.340558	$ (5,630)
39	Depreciation Expense - Depreciation Rates Correction for Ft Benning and Ft Gordon	E-36	R. Smith/R. Trokey	$ (2,033)	$ (1,519)	$ -	8.81%	1.340558	$ 2,036
40	Property Tax Expense	E-37	R. Smith/R. Trokey	$ 7,219	$ 5,393	$ -	8.81%	1.340558	$ (7,230)
41	Income Tax Credits Related to the Inflation Reduction Act	E-38	R. Smith/R. Trokey	$ -	$ -	$ -	8.81%	1.340558	$ -
42	Sum of Staff's Adjustments			$ 238,339	$ 185,753	$ (955,053)			
43	Company Proposed Net Operating Income and Rate Base				$ 1,401,302	$ 26,847,043			
44	**Staff Adjusted Net Operating Income and Staff Adjusted Rate Base**	C			$ 1,587,055	$ 25,891,990			
	Gross Revenue Conversion Factor Difference:								
45	Per Staff	A-1						1.340558	
46	Per Company	A-1						1.340558	
47	Difference							0.000000	
48	Company Adjusted NOI Deficiency	A						$ 530,500	
49	GRCF Difference								$ -
50	Staff REVENUE REQUIREMENT ADJUSTMENTS ABOVE								$ (752,558)
51	Company Requested Base Rate Revenues, Not Including Levelization	A							$ 905,447
52	Reconciled Revenue Requirement								$ 152,889
53	Revenue Requirement Calculated on Schedule A	A							$ 152,889
54	Unidentified Difference (rounding)								$ (0)

Notes and Source
Pre-tax return computed using Gross Revenue Conversion Factor

	D	Rate of Return	6.57%
Effect of Staff Adjustments to Rate Base	A-1	GRCF	x 1.340558
Staff Rate Base Multiplier			8.81%

Georgia Power Company
Revenue Requirement Reconciliation
Retail Electric Amounts
Calendar Year 2025
(Thousands of Dollars)

Line No.	Description	Schedule Reference	Staff Witness	Component (A)	Net Operating Income Amount Sch C.1 (B)	Rate Base Adjustment Sch B.1 (C)	Staff Rate Base Multiplier (D)	Staff Multiplier (E)	Staff Estimated Revenue Requirement Impact (F)
1		D	M. Gorman	ROR Difference				-1.1609%	
2	**Rate Base**	A-1	R. Smith/R. Trokey	GRCF	x			x 1.340600	
3	Rate Base per Company's Filing	B	M. Gorman			$ 28,448,634 x		-1.556%	$ (442,745)
	Estimated Revenue Requirement Effect of Staff NOI and Rate Base Adjustments	Staff Adjustment		Pre-Tax Operating Income Amount				Staff GRCF NOI Multiplier Sch. A-1	
4	Company Supplemental - Rate Base Adjustments	E-1	R. Smith/R. Trokey	$ -	$ -	$ 12,022	8.86%	1.340600	$ 1,065
5	Company Supplemental - Operating Income Adjustments	E-2	R. Smith/R. Trokey	$ (40,100)	$ (29,908)		8.86%	1.340600	$ 40,094
6	Forecasted Revenues	E-3	S. Baron/L. Wellborn	$ 7,752	$ 5,791		8.86%	1.340600	$ (7,763)
7	Stock-Based Compensation	E-4	R. Smith/R. Trokey	$ 28,230	$ 21,089		8.86%	1.340600	$ (28,272)
8	Payroll Tax Expense	E-5	R. Smith/R. Trokey	$ 2,159	$ 1,613		8.86%	1.340600	$ (2,162)
9	Energy Direct Premium Packages	E-6	R. Smith/R. Trokey	$ 1,240	$ 926		8.86%	1.340600	$ (1,242)
10	Executive Financial Planning	E-7	R. Smith/R. Trokey	$ 466	$ 348		8.86%	1.340600	$ (467)
11	Interest Synchronization Adjustment	E-8	R. Smith/R. Trokey	$ -	$ 5,424		8.86%	1.340600	$ (7,271)
12	O&M Scrap Sales Proceeds	E-9	R. Smith/R. Trokey	$ 1,216	$ 908		8.86%	1.340600	$ (1,217)
13	Cash Working Capital	E-10	R. Smith/R. Trokey			$ 300	8.86%	1.340600	$ 27
14	Wireless Co-Location Revenues	E-11	R. Smith/R. Trokey	$ 626	$ 468		8.86%	1.340600	$ (628)
15	Depreciation Expense and Accumulated Depreciation - New Depreciation Rates	E-12	L. Kaufman/R. Smith/R. Trokey	$ 59,513	$ 44,459	$ 141,383	8.86%	1.340600	$ (47,074)
16	Electric Vehicle Make Ready Program	E-13	R. Smith/R. Trokey	$ 1,956	$ 1,461	$ (64,957)	8.86%	1.340600	$ (7,714)
17	Electric Vehicle Community Charging Stations	E-14	R. Smith/R. Trokey	$ 217	$ 162	$ (7,217)	8.86%	1.340600	$ (857)
18	O&M Expense - Electric Vehicle Infrastructure	E-15	D. Mugrace	$ 3,281	$ 2,451		8.86%	1.340600	$ (3,285)
19	O&M Expense - Transmission	E-16	D. Mugrace	$ 3,912	$ 2,923		8.86%	1.340600	$ (3,918)
20	O&M Expense - Distribution	E-17	D. Mugrace	$ 7,140	$ 5,334		8.86%	1.340600	$ (7,151)
21	O&M Expense - Customer Accounting	E-18	D. Mugrace	$ 8,241	$ 6,156		8.86%	1.340600	$ (8,252)
22	O&M Expense - Demonstration & Selling Expenses	E-19	D. Mugrace	$ 1,219	$ 911		8.86%	1.340600	$ (1,221)
23	O&M Expense - Administrative & General Salaries	E-20	D. Mugrace	$ 25	$ 19		8.86%	1.340600	$ (25)
24	O&M Expense - Office Supplies and Expense	E-21	D. Mugrace	$ -	$ -		8.86%	1.340600	$ -
25	O&M Expense - Outside Services Employed	E-22	D. Mugrace	$ 3,258	$ 2,434		8.86%	1.340600	$ (3,263)
26	O&M Expense - Injuries and Damages	E-23	D. Mugrace	$ 1,537	$ 1,148		8.86%	1.340600	$ (1,539)
27	O&M Expense - Employee Pensions and Benefits	E-24	D. Mugrace	$ 12,936	$ 9,664		8.86%	1.340600	$ (12,956)
28	O&M Expense - Customer Service and Information	E-25	D. Mugrace	$ 9,000	$ 6,723		8.86%	1.340600	$ (9,013)
29	O&M Expense - Miscellaneous General and Advertising	E-26	D. Mugrace	$ 2,411	$ 1,801		8.86%	1.340600	$ (2,414)
30	O&M Expense - Maintenance of General Plant	E-27	D. Mugrace	$ -	$ -		8.86%	1.340600	$ -
31	O&M Expense - Adjustment for Inflation	E-28	D. Mugrace	$ 33,717	$ 25,188		8.86%	1.340600	$ (33,767)
32	Labor O&M Expense - Vacancy Rate, Employee Levels, Performance Pay Plan and Overtime	E-29	D. Mugrace	$ 92,846	$ 69,360		8.86%	1.340600	$ (92,984)
33	Transmission Plant Investment	E-30	P. Alvarez/D. Stevens/R. Rana			$ (820,811)	8.86%	1.340600	$ (72,735)
34	Distribution Plant Investment	E-31	P. Alvarez/D. Stevens/R. Rana			$ (902,988)	8.86%	1.340600	$ (80,017)
35	Distributed Energy Resource Management System (DERMS)	E-32	P. Alvarez/D. Stevens/R. Rana			$ (74,633)	8.86%	1.340600	$ (6,613)
36	Transmission Plant - Depreciation Expense and Accumulated Depreciation	E-33	R. Smith/R. Trokey	$ 20,047	$ 14,976	$ 25,846	8.86%	1.340600	$ (17,786)
37	Distribution Plant - Depreciation Expense and Accumulated Depreciation	E-34	R. Smith/R. Trokey	$ 26,164	$ 19,546	$ 32,996	8.86%	1.340600	$ (23,279)
38	Distributed Energy Resource Management System (DERMS) - Amortization and Accumulated Amortiz	E-35	R. Smith/R. Trokey	$ 14,927	$ 11,151	$ 14,390	8.86%	1.340600	$ (13,673)
39	Depreciation Expense - Depreciation Rates Correction for Ft Benning and Ft Gordon	E-36	R. Smith/R. Trokey	$ (2,033)	$ (1,519)	$ -	8.86%	1.340600	$ 2,036
40	Property Tax Expense	E-37	R. Smith/R. Trokey	$ 12,726	$ 9,507	$ -	8.86%	1.340600	$ (12,745)
41	Income Tax Credits Related to the Inflation Reduction Act	E-38	R. Smith/R. Trokey	$ -	$ 400	$ -	8.86%	1.340600	$ (536)
42	Sum of Staff's Adjustments			$ 314,627	$ 240,913	$ (1,643,669)			
43	Company Proposed Net Operating Income and Rate Base				$ 1,241,726	$ 28,448,634			
44	**Staff Adjusted Net Operating Income and Staff Adjusted Rate Base**	C			$ 1,482,639	$ 26,804,965			
	Gross Revenue Conversion Factor Difference:								
45	Per Staff	A-1						1.340600	
46	Per Company	A-1						1.340600	
47	Difference							0.000000	
48	Company Adjusted NOI Deficiency	A						$ 833,549	
49	GRCF Difference								$ -
50	Staff REVENUE REQUIREMENT ADJUSTMENTS ABOVE								$ (911,364)
51	Company Requested Base Rate Revenues, Not Including Levelization	A							$ 1,299,024
52	Reconciled Revenue Requirement								$ 387,659
53	Revenue Requirement Calculated on Schedule A	A							$ 387,659
54	Unidentified Difference (rounding)								$ 0

Notes and Source
Pre-tax return computed using Gross Revenue Conversion Factor

	D	Rate of Return		6.61%
Effect of Staff Adjustments to Rate Base	A-1	GRCF	x	1.340600
Staff Rate Base Multiplier				8.86%