BEFORE THE PUBLIC SERVICE COMMISSION

STATE OF GEORGIA

	)	
	)	
In Re: Georgia Power Company's	)	**Docket No. 44280**
2022 Rate Case	)	
	)	
	)	

REDACTED – PUBLIC DISCLOSURE VERSION

SUPPLEMENTAL DIRECT TESTIMONY OF KEVIN LUCAS, THATCHER YOUNG, AND WILL GIESE

Presented as a panel on behalf
of the Georgia Solar Energy Industries Association,
Solar Energy Industries Association, and Vote Solar

November 18, 2022

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I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE FOR THE RECORD YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A1. [Mr. Lucas] My name is Kevin Lucas. I am the Senior Director of Utility Regulation and Policy at the Solar Energy Industries Association ("SEIA"). My business address is 1425 K St. NW #1000, Washington, DC 20005.

A1. [Mr. Young] My name is Thatcher R. Young. I am Vice-President of Business Development of Velo Solar, LLC ("Velo Solar"). My business address is 154 Krog Street, N.E., Suite 140, Atlanta, Georgia 30307.

A1. [Mr. Giese]. My name is Will Giese. I am Southeast Regional Director for SEIA. My business address is 1425 K St. NW #1000, Washington, DC 20005.

Q2. DID YOU PARTICIPATE IN PANEL THAT SUBMITTED TESTIMONY IN THE FIRST PHASE OF THIS PROCEEDING?

A2. [Mr. Lucas] Yes.

A2. [Mr. Young] Yes.

A2. [Mr. Giese] No, I did not testify in the first phase of this proceeding.

Q3. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A3. Our testimony is provided on behalf of the Georgia Solar Energy Industries Association ("GASEIA"), SEIA, and Vote Solar, as joint intervenors in this proceeding (collectively "GASEIA Intervenors" or "GASEIA").

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A4. The purpose of our testimony is to respond to the Georgia Power Company's ("Georgia Power", "GPC", or "the Company") supplemental direct testimony in this proceeding that focused on RNR customers.[1]

Q5. PLEASE PROVIDE AN OVERVIEW OF YOUR SUPPLEMENTAL TESTIMONY.

[1] Supplemental Direct Testimony of Lee Evans and Larry Legg On Behalf of Georgia Power Company ("Evans/Legg Supplemental"), Supplemental Direct Testimony of Dr. David Gattie On Behalf of Georgia Power Company ("Gattie Supplemental").

A5. We do not believe that GPC has made a good-faith effort to comply with the language in the Commission's final order in the 2022 IRP to "provide, test, and challenge cost-based data" about RNR customers.[2] The Company has failed to provide the cost-based data and analyses directly requested by the Commission. Its reasons for doing so – including that the COSS model is "insufficiently precise … to produce meaningful results" – are directly contradicted by its use of the COSS for other small customer groups. GPC has repeatedly failed to provide complete and accurate responses to discovery requests, incapacitating the ability of other parties to "test and challenge" the data.

Notwithstanding the cost-based data issue, the Company's position regarding the "cost shift" caused by revenue erosion is stunning in its implications. Quite simply, GPC appears to believe it is not merely allowed to keep but in fact *entitled* to recover all revenue shortfalls from revenue erosion from any customer for any reason. This wildly broad reading of its rights to profits is out of step with conventional cost-based regulation applied by state commissions and should be checked.

The Company's quantitative analysis regarding revenue erosion is methodologically flawed beyond repair, while also containing a glaring error that massively inflated its final cost shift value. The Company's choice to compress 1,100 RNR customers (which was already a subset and thus potentially not reflective of the total RNR population) into a mere four "representative" customers introduces errors that were only compounded when these four customers were expanded to represent 5,000. The Company makes no effort to validate whether its approach was robust, whether the four customers represented the group they were supposed to, or how several errors and questionable choices impacted its final results.

The Company's policy argument about states "walking away" from net metering is unsupported. In fact, net metering remains the law of the land in most states and investing in residential and small commercial BTM solar creates jobs and brings investment to the state. Further, states that have made changes away from traditional net metering have landed on

[2] Order Adopting Stipulation ¶71, Docket Nos. 44160 and 44161.

export structures and rates that are far more favorable than GPC's RNR Instantaneous program. The proposal to mandate demand-based rates must be rejected as discriminatory. The Company's main support for this – its revenue erosion analysis – is fatally flawed and contains a major error that undermines its conclusion.

The Company claims that the Commission should wait until it sees how the Inflation Reduction Act will play out. While we agree that the IRA has the potential to be transformative to the solar industry, some of its policies will take time to implement. Further, several of the expanded incentives are only available to commercial taxpayers, not residential customers. State policy support remains critical to grow BTM markets, particularly in the short term while several headwinds persist.

We find the Company's testimony regarding a lack of capacity value for solar to be uncompelling. The Company core argument is a circular; since all existing capacity assets are sunk costs, and since new RNR systems cannot reduce sunk costs, there is no avoided capacity benefit. That argument fails to acknowledge that the Company's system has increased in magnitude every year over the past decade, with future, avoidable costs repeatedly being converted into embedded, sunk costs.

While we were not able to produce all of the cost-based RNR analyses that we had hoped because of the Company's failure to provide timely and usable responses to Public Interest Staff's ("PIA Staff" or "Staff") discovery, we were able to produce high-level metrics that supports our conclusion that the cost to serve RNR customers is lower than non-RNR customers. We also walk through a more detailed Michigan analysis that compares the cost metrics before and after solar was installed to demonstrate the magnitude of cost reduction. We also show that exported energy from RNR customers consistently contributes to load reductions during peak COSS hours and on-peak TOU hours. In each of these cases, it is clear that the burden that RNR customers place on the system during peak hours that drive system costs falls after installing solar and are lower than a typical residential customer.

Finally, we support the Commission working with all stakeholders, including the solar industry and GPC, to address the consumer protection issues that the Company has raised. We recognize that expanding monthly netting has the potential to attract more out of state companies and with them "bad actors." However, this is a complex issue involving multiple organizations, jurisdictions, and state agencies and so a comprehensive and thoughtful approach is required. We would recommend the Commission invite the Attorney General's office to participate in an inter-agency task force to develop a comprehensive set of policy recommendations for Commissioners to consider within six months. Such a task force should include Georgia Power, solar industry representatives, Commission Staff, representatives from the EMCs and municipal utilities, and possibly other state agencies like the Governor's Office of Consumer Protections.

Q6. WHAT ARE YOUR OVERALL RECOMMENDATIONS?

A6. We respectfully make the following recommendations of the Commission:

- The Commission should recognize that GPC failed to provide a cost-based analysis related to RNR customers and failed to provide responsive data to PIA Staff's discovery requests which ultimately impaired the ability for parties to "provide, test, and challenge cost-based data".
- The Commission should require GPC to remove or modify its disclaimer on the COSS study that implies that non-Staff parties are violating Georgia law by using the model.
- The Commission should reject GPC's quantitative analysis related to revenue erosion as methodologically flawed while noting the impact of the major error related to summer bills.
- The Commission should reject GPC's policy-based arguments against extending the RNR Monthly Netting program and find instead that growing a robust BTM solar market will lead to increased investment, economic activity, and job growth.
- The Commission should reject GPC's request that new RNR customers must take service on a three-part rate design as unfairly discriminatory.
- The Commission should continue to quantify capacity value that BTM solar exports produce and add this value to the Solar Avoided Cost calculation.
- The Commission should accept Joint Intervenors' analysis that shows that RNR customers have lower cost of service than non-RNR customers and that the cost to service RNR customers is lower after they install solar than before they install solar.
- The Commission should extend the RNR Monthly Netting program with no cap while also implementing a $20 minimum total bill that is inclusive of the customer charge.
- The Commission should convene an inter-agency task force to develop recommendations on consumer protection issues that may affect a growing RNR market.

II. GPC HAS NOT COMPLIED WITH THE FINAL IRP ORDER DIRECTING GPC TO PROVIDE COST-BASED RNR DATA AND ANALYSES

Q7. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A7. We discuss the Company's approach to the RNR Tariff issue in its written testimony, hearing testimony, and responses to discovery.

Q8. PLEASE SUMMARIZE YOUR FINDINGS.

A8. We do not believe that GPC has made a good-faith effort to comply with the language in the Commission's final order in the 2022 IRP to "provide, test, and challenge cost-based data" about RNR customers.[3] The Company has failed to provide the cost-based data and analyses directly requested by the Commission. Its reasons for doing so – including that the COSS model is "insufficiently precise … to produce meaningful results" – are directly contradicted by its use of the COSS for other small customer groups. GPC has repeatedly failed to provide complete and accurate responses to discovery requests, incapacitating the ability of other parties to "test and challenge" the data.

Notwithstanding the cost-based data issue, the Company's position regarding the "cost shift" caused by revenue erosion is stunning in its implications. Quite simply, GPC appears to believe it is not merely allowed to keep but in fact *entitled* to recover all revenue shortfalls from revenue erosion from any customer for any reason. This wildly broad reading of its rights to profits is out of step with conventional cost-based regulation and should be checked.

Q9. WHAT IS YOUR RECOMMENDATION ON THE COMPANY'S ANALYSIS?

A9. We implore the Commission to reject GPC's unsupported opposition to expanded RNR monthly netting and move forward with an expansion of the pilot program until such time as GPC adopts a more rigorous, cost-based approach to this issue. The Commission ordered that all parties – including the Company –provide data so that it can make an informed

[3] Order Adopting Stipulation ¶71, Docket Nos. 44160 and 44161.

decision about RNR customers rather than debating "whether or not to continue temporarily doling out net metering to a subset of customers."[4] We support the Commission's approach and have worked as diligently as possible to provide it with the data and analysis on which it could rely to make this decision.

But we have been unable to provide the level of analysis that we would like this Commission to have available, due to the Company's refusal to share meaningful data or conduct its own analysis. GPC did not produce a cost-based analysis, claiming it was not possible. The discovery process and response timeline were not conducive to establishing a robust baseline set of information. GPC's repeated delays in providing accurate and usable response to PIA Staff discovery – the only vector that non-Staff intervenors had for this data – prevented us from testing and challenging the Company's positions. Finally, GPC's absolutist position that it is entitled to any revenue erosion from any group of customers for any reason is a breathtakingly overreach and cannot be allowed to stand.

GPC Has Failed to Provide a Cost-Based Analysis of RNR Customers, Despite the Commission's Direct Requirement

Q10. PLEASE REVIEW THE HISTORY OF PARTIES' RNR TESTIMONY IN THE 2022 IRP AND THIS CASE.

A10. Beginning in the 2022 IRP case, the Company advanced arguments claiming that RNR Monthly Netting customers were causing a "cost shift" to other customers.[5] GPC claimed that RNR Monthly customers caused a $382,000 and $968,000 revenue erosion in 2020 and 2021, respectively, that needed to be recaptured from other non-participating customers.[6]

[4] Id.
[5] Direct Testimony of Jeffrey R. Grubb, A. Wilson Mallard, Michael B. Robinson, and Jeffrey B. Weathers On behalf of Georgia Power Company at 49, Docket Nos. 44160 & 44161. ("GPC IRP Direct")
[6] Direct Testimony of GASEIA, SEIA, and Vote Solar at 38, Docket Nos. 44160 & 44161. ("GASEIA Intervenors IRP Direct")

Because of this and other issues,[7] it recommended that the 5,000 RNR Monthly limit not be expanded.[8]

GASEIA Intervenors filed testimony in the IRP that refuted GPC's claims. We revealed that the Company's analysis was rooted in revenue erosion, not in cost of service. Further, we demonstrated that these costs are not recovered from ratepayers in the short run and that the presence of BTM solar moderates infrastructure needs in the long run. Because the Company did not perform any short-run or long-run cost of service analysis, it had no basis to claim a cost shift exists.[9]

In the Commission's IRP order, it directed the Company and parties to consider the RNR issue in the then-upcoming rate case:

> Rather than continuing to try to address rooftop solar with a series of temporary and partial measures where some customers receive net metering while others receive only avoided cost or, in some cases, nothing at all, I move that the Commission direct Staff and the Company to each address the appropriate structure and pricing of the RNR-10 tariff in the current rate case so that the Commission can move towards a fair and long term way of addressing the issue.
>
> In this IRP, we simply do not have the cost information necessary to set just and reasonable rates, terms, and conditions for rooftop solar. In addition, we do not have the information to determine whether or how such rates, terms, and conditions would impact other customers. Under my motion, the parties in the rate case would have the opportunity to provide, test, and challenge cost-based data and the Commission would have more options than simply deciding whether or not to continue temporarily doling out net metering to a subset of customers.[10]

Fast forwarding to the current rate case, the Company reintroduced its revenue erosion analysis in the first phase of this docket. GPC proposed to adjust its target base revenue requirement by $1.4 million, claiming that it was necessary to recoup revenue loss from Monthly RNR customers.[11] It also repeated word-for-word its other "concerns" from

[7] The Company also identified three other "concerns": operational concerns with an increase in unplanned variable energy resources; the infiltration of aggressive and uninformed solar marketers misinforming customers; and noncompliance with the Company's rules, regulations, and program requirements for interconnection of behind the meter generation. GPC IRP Direct at 49.
[8] GPC IRP Direct at 49.
[9] GASEIA Intervenors IRP Direct at 39.
[10] Order Adopting Stipulation ¶71, Docket Nos. 44160 and 44161.
[11] Legg Direct at 11.

the IRP related to unspecified operational issues and an increase in "bad actors" in the BTM solar market.[12]

In the first phase of this case, GASEIA Intervenors again rebutted the Company's revenue erosion claims, pointing out again the lack of any cost of service analysis to support its "cost shift" claim. After all, one cannot credibly claim that revenue erosion causes a cost shift without actually analyzing whether costs fell by a commensurate amount; if costs fall from $10 to $7, then a corresponding revenue reduction from $10 to $7 does not cause a cost shift. We also contrasted the magnitude of the purported RNR Monthly Netting revenue shift ($0.20 per year for a typical residential customer) with the Company's requests in this case ($195 per year), the projection of Vogtle costs ($166 per year), and the excess revenue collection above its central ROE but below the ROE dead band ($46 in 2021.)[13]

In the second phase of this case, GPC expanded on its RNR testimony but did not fundamentally shift its approach. It conducted a more detailed revenue erosion analysis, this time reverse engineering the pre-solar load profile of RNR customers with 12 months of data, selecting four non-solar proxy customers to represent the RNR customers, and then calculating what bills would be on the R and TOU-RD tariffs before and after the installation of BTM solar.[14] It also submitted policy-based testimony suggesting that states were rapidly shifting away from traditional net metering.[15] Based on the results from its updated RNR customer and policy analysis, the Company recommends the Monthly RNR program not be expanded and that all new RNR customer starting in 2023 be required to take service on a three-part rate such as the TOU-RD tariff.[16]

Q11. HAS THE COMMISSION RECENTLY OPINED ON THE NEED FOR A COST-BASED ANALYSIS OF RNR CUSTOMERS?

[12] Id.
[13] Direct Testimony of Kevin Lucas and Thatcher Young, Presented as a panel on behalf of the Georgia Solar Energy Industries Association, Solar Energy Industries Association, and Vote Solar at 46. ("GASEIA Intervenors Phase I Direct").
[14] Evans and Legg Supplemental at 12. We discuss the Company's analysis below in Section III.
[15] Gattie Supplemental at 5.
[16] Id at 14.

A11. Yes. In the 2022 IRP order, the Commission adopted a motion with the intention that "parties in the rate case would have the opportunity to provide, test, and challenge cost-based data" so that the Commission could make a longer-term decision about the RNR program based on more robust data and analysis.[17]

Q12. DID GPC PROVIDE THIS DATA OR ANALYSIS TO THE COMMISSION AND OTHER PARTIES?

A12. No, it did not. Despite being specifically directed by the Commission to provide cost-based data to support its claim, the Company has failed to do so. GPC's supplemental RNR testimony extends its revenue erosion argument but does not include any cost-based analysis.

Q13. WHAT ARE YOU BASING THAT CONCLUSION ON?

A13. I am basing it on the Company's own written testimony, hearing testimony, and responses to discovery. In the November 10th hearing, Company witnesses Evans and Legg discussed their RNR testimony. When asked whether the Company conducted a cost of service study that distinguishes RNR customers from non-RNR customers, the Company responded "No we have not. A cost of service study designed for such a small population would be unreliable. To borrow a phrase from Mr. Watkins, [yesterday] staff's witness, with Mr. Watkins, the cost of service study does not have the surgical precision to determine costs for such a small population of residential customers, so breaking them out separately would not produce reliable results."[18]

GPC was also asked in discovery to elaborate on its RNR testimony on this point. The Company was asked to "provide all data, studies and analyses that have been performed by, or on behalf of, the Company regarding cost shifting, revenue erosion, or that indicate rooftop solar customers on the RNR Monthly Netting tariff are not paying their full cost of service." The Company responded with workpapers that further supported its revenue erosion analysis found in Witness Evans' and Legg's supplemental testimony but did not provide any workpapers or analyses related to cost of service of RNR customers. When

[17] Order Adopting Stipulation ¶71, Docket Nos. 44160 and 44161.
[18] 11/10/2022 hearing video 4:21:12.

asked to confirm that its analysis was based on revenue erosion from retail rates, the Company confirmed "The cost-shift analysis is based on the amount of cost recovery that will be shifted from RNR Monthly Netting pilot participants on the Residential Service rate ("R") to all other non-participating customers."[19]

The Company was also asked "Has Dr. Gattie (or anyone else) performed a cost-of-service study (of solar customer-generators) to validate this assertion?" The Company's response was "Dr. Gattie did not perform or rely upon a cost-of-service study to validate this assertion. The assertion is premised on Dr. Gattie's knowledge that electricity exported from the solar customer-generator onto the grid does not offset the costs associated with the Company's existing infrastructure investments that are required to serve electricity to the customer-generator."[20]

Q14. DO YOU BELIEVE THAT THE COMPANY' COSS MODEL IS INCAPABLE OF PRODUCING RELIABLE RESULTS FOR THIS TYPE OF STUDY?

A14. No, we do not. The Company's claim that its COSS model "does not have [] surgical precision" and that analysis for a small group of customers would be "unreliable" is unconvincing. The Company's COSS working precision depends on the data element, but it performs calculations at very high precision level.

Its load values are calculated to the nearest [redacted].[21] For 12CP allocators, this produces values at a resolution of roughly [redacted]. For 4CP allocators, the resolution is [redacted]. Sales are loaded into the model at the [redacted] resolution for higher voltage levels B through F and at the [redacted] level – or [redacted] significant digits – for voltage level G.[22] Line losses are also recorded to the [redacted] level, producing a line loss factor that is presented to [redacted] decimals of precision. Revenue is entered to the nearest [redacted], also recorded at [redacted] significant digits. Given that NASA's use of "only" 15 decimals of π for interplanetary navigation

[19] STF-TAI-8-15
[20] STF-TAI-8-11
[21] All values from this paragraph are from STF-TAI-1-1 Attachment A Trade Secret.
[22] For example, the sales for the residential class is entered into the model as [redacted] MWh, or equal to [redacted] watts.

would allow it to position the Voyager 1 spacecraft to less than a half inch of error, we'd say that the GPC model is sufficiently precise to handle an analysis for RNR customers.[23]

Q15. DOES THE COMPANY'S MODEL CURRENTLY INCLUDE CUSTOMER GROUPS THAT ARE SIMILARLY SIZED AS THE RNR "CLASS"?

A15. Yes. According to the Company's analysis, the average inflow for 1,110 RNR Monthly Netting participants that had 12 months of data in 2021 was 13,217 kWh.[24] This figure only represents energy consumed from the Company's grid, and therefor does not include any self-consumed solar generation or monthly netting impacts. This value is slightly higher than the average test year consumption of 12,281 kWh per year.[25] GPC projects that 4,657 of the 5,000 customers in the RNR Monthly Netting pilot will be residential customers.[26] Applying these values, this group would use roughly 61,550 MWh per year.

GPC's COSS includes four separate rate classes that use roughly the same or less energy per year, and four more than use marginally more. These values are shown below in Table 1. If GPC truly believes that its COSS is insufficiently precision and produces unreliable results for small customer groups, it should explain to the Commission why it calculates revenue requirements for actual customers based on even smaller rate groups.

COSS Rate Class	Customers	Sales (MWh)
R, RM	2,177,372	26,872,898
TOU-PEV	6,528	108,480
G	16	105,652
UD	15,942	92,151
TOU-REO	6,613	90,549
TOU-HLF	16	62,398
RNR R Estimated	**4,657**	**61,550**
TC	5,368	40,728
SAS	311	28,981
OGS	255	8,267

Table 1 - COSS Rate Class Size Comparison

[23] https://www.jpl.nasa.gov/edu/news/2016/3/16/how-many-decimals-of-pi-do-we-really-need/
[24] STF-TAI-7-1 Attachment B.
[25] Exhibit LPE-1 and LPE-2.
[26] STF-TAI-1-27 Attachment A.

GPC's Primary Analysis Contains a Major and Obvious Error that Should have been Avoided

Q16. WHILE GPC DID NOT PROVIDE A COST-BASED ANALYSIS, DID IT PROVIDE ANY ANALYSIS TO SUPPORT THEIR RNR TESTIMONY?

A16. Yes. The Company conducted a revenue erosion analysis that claimed to show a major cost shift from RNR customers to non-RNR customers. The conclusion of this analysis is shown below in Figure 1. In essence, GPC calculated that RNR customers were shifting $1,356 per year to non-participating customers, $1,093 of which was due simply from taking service on the R tariff. By contrast, it claimed the total cost shift value fell to $291 per year if RNR customers took service on the TOU-RD rate, of which $254 was due to the TOU-RD rate structure itself.

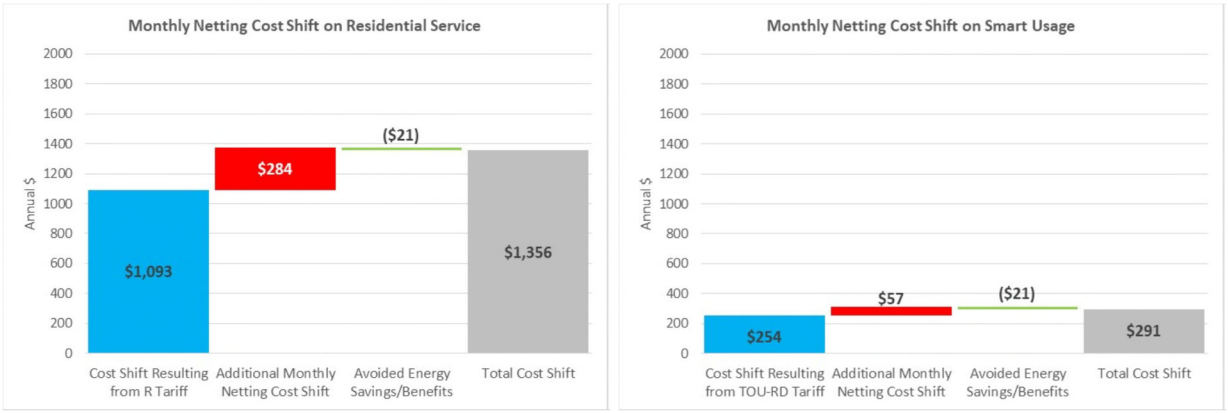


Figure 1 - GPC Monthly Netting Cost Shift Analysis

Q17. WHAT WAS YOUR INITIAL RESPONSE TO THIS ANALYSIS?

A17. Aside from the obvious – that it was not a cost-based analysis – we were struck by how much of the cost shift the Company claimed was due to self-consumption on the R tariff structure rather than the Monthly Netting program. This was not the focus of the Company's testimony prior this point, and the Company's workpapers regarding its $1.4 revenue erosion / cost shift claim did not focus on self-consumption. This opens a very fraught line of inquiry as it suggests that actions that customer take to reduce their usage is somehow a form of cost shift to other customers. And sure enough, this is exactly what the Company argues.

Q18. DID YOU ANALYZE THE WORKPAPERS AFTER THEY WERE PROVIDED?

A18. Yes. the basic approach involves calculating what solar customers would have paid for service on the R and TOU-RD tariff before and after they installed solar. The difference was broken into the two categories shown above – impacts from rate design and impacts from monthly netting. The Company's result that the R tariff was producing nearly $1,100 per year of cost shift was one of the main reasons it recommended that all future RNR customers be required to take service on a three-part rate such as the TOU-RD.[27]

Q19. WHAT IS YOUR IMPRESSION OF THE COMPANY'S ANALYSIS?

A19. We found it poorly conceived and executed, replete with inappropriate assumptions and simplifications. While we discuss the myriad issues with analysis below,[28] the biggest issue is one that clearly should have been avoided.

Q20. WHAT IS THAT ISSUE?

A20. The workpaper has a glaring error: the bill for usage over 1,000 kWh in summer months for the R tariff is multiplied by 2.[29] This is due to a mistake in a formula where rather than rounding the value to 2 decimal places, the workpaper multiplies this value by 2.

Q21. WHY DO YOU BELIEVE THIS ERROR SHOULD HAVE BEEN CAUGHT RATHER THAN JUST ACCEPTING IT AS AN INADVERTENT ERROR?

A21. For several reasons. First, the magnitude of the error is immediately obvious in the results. For the 4th quartile customer group, May usage over 1,000 kWh per month was about $100, but June usage over 1,000 kWh was $650. The Company should be sufficiently familiar with its tariffs that it should have seen this anomalous result, particularly given usage over 1,000 kWh only went up roughly 60% rather than 300% between May and June.[30]

Second, the workpaper also includes a direct comparison of bills between the R and TOU-RD rate, including for pre-solar customers. Due to the error, the 4th quartile customer shows an annual bill of $5,116 on the R tariff compared to $2,909 on the TOU-RD tariff.

[27] Evans and Legg Supplemental at 14.
[28] See Section IV, *infra.*
[29] STF-TAI-7 Attachment B.
[30] Block 3 rates in summer are about twice as high as in non-summer, so a three-fold increase in usage over 1,000 kWh would have been needed to produce a six-fold increase in that component of the bill.

Given these tariffs are intended to be revenue neutral with respect to each other, it is a major red flag for a non-solar customer to see a bill 75% higher on the R tariff.

Third, extraordinary claims require extraordinary proof. Claiming that BTM solar is so punitive to non-solar customers that even self-consumption drove more than a thousand dollars of cost shift on the R tariff is a bold claim. This was the "smoking gun" of the Company's only new quantitative analysis on the cost-shift issue in this case, and it should have been more diligent to ensure it was presenting accurate information to the Commission.

Q22. WHAT HAPPENS WHEN YOU CORRECT THIS ERROR?

A22. The Company's cost shift argument is severely wounded. Because the error occurred only on one component (pre-solar use on the R tariff), its impact was maximized. Correcting only this error and rerunning the Company's analysis produces substantially different results. The $1,093 of "cost shift" from the R tariff falls to $560. So instead of the R tariff causing $840 more per year in "cost shift" than the TOU-RD tariff, the value falls to $305. Even without addressing the many other issues with the Company's analysis, this alone slashes the impact of and justification for requiring new RNR customers to move to three-part rates.

GPC Claims Parties Trying to be Responsive to the Commission are Breaking Georgia State Law

Q23. DID THE COMMISSION DECLARE THAT "THE PARTIES IN THE RATE CASE WOULD HAVE THE OPPORTUNITY TO PROVIDE, TEST, AND CHALLENGE COST-BASED DATA"?

A23. Yes, it did.

Q24. WHAT ARE SOME OF THE WAYS THAT YOU WOULD TAKE ADVANTAGE OF THIS OPPORTUNITY?

A24. [Mr. Lucas] In any other case that I have worked in, if I were tasked with performing a cost-based analysis of BTM solar customers, I would have asked multiple rounds of discovery about the Company's testimony, exhibits, models, and discovery responses. After obtaining and validating the requisite data, I would have utilized the Company's models where possible

to perform the cost-based analysis. This includes using and modifying the COSS as necessary.

Q25. DID YOU HAVE THE OPPORTUNITY TO PERFORM THESE STEPS IN THIS CASE?

A25. No, we were not. As we discussed in our first-round testimony, intervenors other than PIA Staff are not allowed to ask discovery. While we were able to leverage Staff's requests where possible, as discussed below, the Company's response to Staff's requests were repeatedly non-responsive and unusable. We respectively repeat our request that the Commission expand discovery rights for parties.

Q26. IF YOU HAD BEEN ABLE TO RECEIVE AND VALIDATE THE NEEDED DATA, DID ANYTHING ELSE PREVENT YOU FROM CONDUCTING THE ANALYSIS THE COMMISSION REQUESTED?

A26. Yes. The Company has placed a deeply chilling disclaimer in the discovery response that accompanies working versions of the COSS. The text is shown below in full.

> Included in this response is the Cost of Service model used by Georgia Power in its cost of service study (the "Software"). The Software is a working, proprietary Cost of Service model. The Software is being provided solely for PIA Staff's review in connection with the 2022 Rate Case. **Use of the Software by others is strictly prohibited**. The Software should not be shared with anyone, including consultants, who have not signed a consultant acknowledgement or equivalent confidentiality agreement with Georgia Power. While the resulting numbers from the Software are not necessarily trade secret information, **Georgia Power will consider any unauthorized use of the Software itself to constitute misappropriation of a trade secret in violation of the Georgia Trade Secrets Act of 1990, O.C.G.A. § § 10-1-760 et seq., as well as violation of Commission rules.**
>
> The Software and any attendant documentation contain valuable intellectual property and proprietary information belonging to Georgia Power and Southern Company. The Software is provided for review as a single product. **Its component parts may not be separated for use. Reproduction or distribution of the Software source code, object code, or any copy thereof is strictly prohibited**. All title and copyrights in and to the Software, any accompanying printed materials, and any copies of the Software, are owned by Georgia Power and its parent and/or affiliates. The Software is protected by copyright laws and international treaty provisions.[31]

Q27. WHICH OF THESE CONDITIONS WOULD YOU NEED TO BREAK TO BE ABLE TO CONDUCT THE ANALYSIS YOU DISCUSSED ABOVE?

[31] STF-TAI-1-1. Emphasis added.

A27. Several. First, GASEIA Intervenors are not Staff. As such, us merely using the working COSS model is "strictly prohibited." Given that simply opening the working model ("Use by other is strictly prohibited") is not allowed, it follows that making a copy ("Reproduction… is strictly prohibited"), making any modification or manipulation of the model needed to perform the analysis discussed above ("Its component parts may not be separated for use") would constitute "unauthorized use."

Further, GPC is explicit that it will "consider any unauthorized usage" – i.e., any usage whatsoever by any party other than Staff – "a misappropriation of a trade secret in violation of the Georgia Trade Secrets Act of 1990." Simply put, if any party other than Staff even opens the COSS, much less uses it to perform any analysis, in GPC's view, they are breaking the law.

Q28. HAVE YOU EVER SEEN THIS TYPE OF RESTRICTION ON A COSS OR OTHER COMMON RATE CASE MATERIALS?

A28. Never. This is completely unprecedented from our experience. While we have experienced utilities questionably declaring certain files or models confidential, we have never been threatened with breaking the law merely by opening a utility's COSS model. Even worse, GPC included this chilling disclaimer even after the Commission explicitly allowed all parties – not just Staff – to "test and challenge" cost-based data.

Q29. WHAT DO YOU RECOMMEND WITH RESPECT TO THIS ISSUE?

A29. While it ended up being moot in this proceeding because of the Company's inability to provide the requested cost-based data in a timely manner, this type of restriction should not be permitted in a public forum. The Commission should direct GPC to remove or modify this disclaimer from all future rate cases and ensure that any party that have properly executed a non-disclosure agreement can use the COSS in any way without being considered to be misappropriating trade secrets, violating Georgia state law, and breaking Commission rules.

GPC's Responses to RNR Discovery Were Repeatedly Non-Responsive

Q30. PLEASE REVIEW THE TIMELINE FOR THE RNR PORTION OF THIS RATE CASE.

A30. Staff had filed a data request on September 16, 2022, asking "all data, studies and analyses … regarding cost shifting, revenue erosion, or that indicate rooftop solar customers on the RNR Monthly Netting tariff are not paying their full cost of service."[32] The response to this request was due October 17, 2022. The Company responded on that day saying it would update its response after filing its RNR testimony, due on October 20, 2020. On October 21, 2022, the Company supplemented its response to include workpapers associated with the revenue erosion analysis.

On October 27, Staff filed another set of data requests that asked more detailed questions about the Company's RNR testimony and requested hourly data and system information for 2018-2021 "for all RNR customers."[33] Under the shortened discovery timeline for the RNR phase of the proceeding, responses were due Wednesday, November 9, 2022, directly in the middle of the first round of intervenor hearings. This was nine days before intervenor RNR testimony was due on Friday, November 18, 2022.

After testifying and returning from Atlanta on Thursday, November 10, 2022, we reviewed the Company's responses on Friday, November 11, 2022. At that time, we discovered that the Company's responses to STF-TAI-8-9, which requested the hourly RNR usage data, contained clear errors. For example, the data request specified that a common customer ID be used "that can be traced across files and years," yet the hourly data files and system information file contained independent customer IDs that were not possible to reconcile.[34]

On Monday, November 14, 2022, at nearly 9 PM, GASEIA Intervenors were notified by the Company that supplemental files had been created. While the supplemental file did appear to provide a consistent customer ID for use across files, it still was non-responsive to

[32] STF-TAI-7-1.
[33] STF-TAI-8-9.
[34] STF-TAI-8-9.

Staff's original request. The Company claimed it provided data on all residential RNR customers with a full year of data for the respective year who had usage from and pushback to the system in that year. This additional restriction – customers "with a full year of data" – was nowhere in the original request and resulted in only 1,271 of the 7,297 customers (17%) in the system information file having corresponding hourly data.

PIA Staff's data request could not have been clearer: "Please provide hourly consumption and hourly export data for 2018, 2019, 2020, and 2021 for **all RNR customers.** If some customers do not have hourly consumption or export data over this time period, provide the data that the Company does have."[35] Not only was there no mention of only customers with a full year of data, or only customers with a full year of data who had usage and pushback to the system in that year, the request specifically asked for all available data even if it was incomplete. It is inconceivable that GPC could inadvertently misinterpret this clear, concise request to provide all the hourly data it had for all RNR customers.

More problematic, after correcting the customer ID so that system information could be reconciled with hourly load data, it became obvious that the Company had again failed to provide information that was requested. The system information request asked for "a separate file that indicates for each customer **the date of final system interconnection**, the AC and DC system capacity sizes, the tariff on which the customer takes service, and the zip code of the customer's service location."[36]

The system information file contains only one date element, titled "Established Date." Of the 7,297 systems identified in this file, only 14 had established dates prior to 2020.[37] However, the 2019 hourly data file contained more than 700 customers with exported energy.[38] Given it is not possible for a customer to have exported energy prior to installing her PV system, clearly, the "established date" value is not the date of final

[35] STF-TAI-8-9a. emphasis added.
[36] STF-TAI-8-9b. emphasis added.
[37] STF-TAI-8-9b Attachment D Supplemental.
[38] STF-TAI-8-9a Attachment C.

interconnection. More likely it represents the date that a customer (many of whom had existing solar systems) was added to the RNR tariff, which is not what was requested. GASEIA informed the Company of these continued issues with its supplemental responses on the afternoon of Tuesday November 15, 2022.

Q31. DID YOU EVENTUALLY HEAR BACK FROM THE COMPANY REGARDING THESE OPEN ISSUES?

A31. Yes. At 10:30 PM on Thursday November 17, 2022, the night before testimony was due, the Company responded saying it believed its responses were sufficiently responsive. It claimed that providing the data it did for its own analysis was a sufficient replacement for "all data" for RNR customers, even though the discovery request made no reference to the Company's analysis nor limited the data to those figures. It claimed that it was providing customers with only 12 months of data in a given year, even though PIA Staff specifically asked for all data available even if some were missing. It also acknowledged that Established Date was in fact the date the customer was added to the RNR tariff and not when systems were connected, but said it should be "very closely aligned" with the interconnection date.

Q32. WHAT IS YOUR RESPONSE TO THESE CLAIMS?

A32. The Company's claims are simply inaccurate. The Company provided an example of a customer that came online in October 2020 would not be included in the hourly data file, but sure enough, there were in fact 72 customers that came online in October 2020 that were in the hourly data file. In fact, many systems that came online in the middle of the year were present in the hourly data files. In the 2019 file, only 520 of the 721 customers had data on 1/1/2019. In the 2020 file, only 650 of the 1,169 had data on 1/1/2020. In both files, customers were added throughout the year, contrary to the Company's claims that it only provided customers with 12 months of data in a given year.

Likewise, the contention that the Established Date was "very closely aligned" with the interconnection date is readily disproved in the data. Only two customers had Established Dates in 2019 (both in December), but there were 721 customers that showed outflow during 2019. Unless the Company is claiming that all of these customers improperly interconnected

their systems prior to completing the requisite steps, then the much more likely outcome is that these are the many preexisting systems that were added to the RNR tariff. In these cases, the Established Date is meaningless when trying to compare usage before and after solar.

Despite these clear and continuing issues, no additional or supplemental workpapers were provided. As such, we were forced to file this testimony based on partial data and only able to conduct some of the analyses we had hoped.

Q33. WHAT IS THE RESULT OF THIS DISCOVERY ISSUE?

A33. The one tranche of data that might be able to shed some light on *the* key question in this proceeding – whether RNR customers have a different cost of service after installing solar – was repeatedly delayed by the Company's failure to comply with clear discovery requests. How the Company could reasonably confuse "all data" with "some data" or thought "final system interconnection date" meant "date when system was added to the RNR tariff" is difficult to understand.

GPC Believes It is Entitled to Recover Any Revenue Erosion Regardless of its Earnings

Q34. PLEASE DESCRIBE HOW GPC PROPOSES TO ADDRESS THE REVENUE EROSION FROM RNR MONTHLY NETTING CUSTOMERS.

A34. The Company proposed to make an adjustment of roughly $1.4 million to its target base revenue to "to account for revenue erosion resulting from the Renewable and Non-renewable ("RNR") tariff monthly netting pilot."[39] This adjustment would increase the Company's overall base revenue requirement by a corresponding amount, which would then trickle through to the ECCR and NCRR riders that are calculated based on a percentage of base revenues. All told, the Company's analysis would result in a test year net increase of $1.8 million in revenue between base rates, riders, and RNR credit offsets.[40]

[39] Legg Direct at 5
[40] STF-TAI-1-27 Attachment A.

Q35. IF THIS REVENUE ADJUSTMENT WAS NOT MADE BY THE COMPANY IN THIS RATE CASE, WOULD THE REVENUE EROSION FROM RNR MONTHLY NETTING CUSTOMERS BE COLLECTED FROM OTHER NON-PARTICIPATING CUSTOMERS?

A35. No, it would not. As we discussed in our IRP testimony, a reduction in revenue does not automatically turn into a cost that is recovered from other customers; it simply lowers revenue, which in turn lowers Company profits.[41]

Q36. IF THE PROPOSED REVENUE ADJUSTMENT IS APPROVED, WHAT WILL HAPPEN?

A36. Based on the last eleven years of history, it will not be used to make up a revenue shortfall but rather would only enhance the Company's profits.

Q37. PLEASE EXPLAIN FURTHER.

A37. The Company's earnings are governed by a ROE earnings band. This structure, which we discussed extensively in our Phase 1 testimony, allows the Company to keep 100% of revenues above its approved ROE but under the top of the earnings dead band.[42] In every one of the past 11 years, the Company has collected revenues beyond its central approved ROE, resulting in profits higher than the central value approved by the Commission.[43]

In fact, in 2020, the Company's actual ROE was 11.89%, above the Commission-approved ROE of 10.5% but below the upper ROE dead band of 12.0%. In this case, the Company retained 100% of the $217 million revenue surplus. In 2021, the Company's performance was even better, with an actual ROE of 12.09%, substantially above the Commission-approved 10.5% and above the upper ROE dead band of 12.0%. This resulted in a revenue surplus of $258 million, of which only $5.7 million was refunded to customers.[44]

In years in which the Company earns between its approved ROE and the upper ROE dead band (e.g., 2020), 100% of any revenue adjustment would be collected from customers

[41] GASEIA Intervenors IRP Direct at 39.
[42] See e.g., GASEIA Intervenors Direct Section IV.
[43] Id. at 43.
[44] $14.2 million was over the ROE dead band. Only $5.7 million (40%) was refunded to customers; another $5.7 million (40%) was used to pay down the Company's CCR regulatory asset, and the Company retained $2.8 million (20%). Georgia Power 2021 ASR Report.

and simply added to the Company's revenue surplus. In years in which the Company earns more than the upper ROE dead band (e.g., 2021), 100% of any revenue adjustment would still be collected from customers, but 40% would be directly refunded to customers, 40% would be kept to pay down future costs, and 20% would be retained by the Company.[45]

The only way that the revenue adjustment would not simply add to the Company's revenue surplus is if it were earning less than the Commission-approved ROE, which is currently set at 10.5%. This has never happened since 2011. And even if the Company is earning below its central ROE value, it does not have any recourse to seek recovery of those revenues unless the ROE falls below the bottom of the ROE dead band, currently set at 9.5%. Given Southern Company's recent 2022 Q3 earnings report, it appears that 2022 will be another banner year for GPC, with 2022 year-to-date net income 80% higher than in 2021.[46,47]

In light of this dynamic, revenue erosion from RNR Monthly Netting customers is not a "cost shift" to other customers. It does not contribute to under-collection of revenues because there is no under-collection of revenues. Simply put, an approved revenue adjustment for RNR Monthly Netting revenue erosion will produce only one outcome: enhancing the Company's already-massive revenue surplus.

Q38. DESPITE THE COHERENT LOGIC OF YOUR PREVIOUS ARGUMENT, HAS GPC INVESTIGATED HOW THE EARNINGS BAND MECHANISM AND REVENUE EROSION INTERACT?

[45] In the case that the revenue adjustment would put the Company over the upper ROE dead band, the portion of the adjustment under the limit would be kept entirely by the Company, while the portion over the limit would be split 40%/40%/20%.

[46] Q3 Earnings Package, Georgia Power. 2022 YTD net income $1.85 billion vs. 2021 TYD net income $1.03 billion. https://s27.q4cdn.com/273397814/files/doc_financials/2022/q3/Earnings-Release-Q3-2022-IR.pdf

[47] "Our third quarter financial results continue to support our full year earnings objectives. And the economies within our service territories remain strong, including customer growth and economic activity that has outpaced our expectations. Given our financial performance through the third quarter, we expect full year adjusted earnings per share near the top of our earnings guidance range." "The primary drivers for the year-over-year increase are higher revenues associated with increased usage and retail pricing at our regulated utilities." Southern Company's Third Quarter 2022 Earnings Call transcript, available at https://seekingalpha.com/article/4550067-southern-company-q3-2022-earnings-call-transcript

A38. No, it has not. When asked this specific question, it stated "the Company considers the total retail revenues and its retail cost of service as a whole in its calculation of actual earned retail ROE and the impact on the earnings band. Therefore, the Company has not specifically evaluated the isolated impact of the revenue erosion or cost shifting caused by RNR customers within or outside of the earnings band."[48]

It continued:

> Any revenue erosion not captured through retail rates, which occurs during the 3-year alternate rate plan will serve to lower the Company's earned ROE. As a matter of appropriate ratemaking principles, to set retail rates at the correct level to recover the Company's retail cost of service from customers**, any amount of revenues lost from, or avoided by, a certain group of customers must be recovered from the remaining body of customers**. This is true unless the amount of lost or avoided revenues also result in a comparable reduction in the Company's retail cost of service/ revenue requirement.[49]

Q39. WHAT IS YOUR REACTION TO THIS RESPONSE?

A39. It is shocking on its own, but when combined with the Company's other responses, it is utterly stunning in its scope and implications. In essence, the Company claims that it is owned "any amount" of revenue that is avoided by any group of customers through any action. The Company does not qualify this statement on whether this revenue erosion comes from a reduction in usage, behavior changes, installation of DER, or anything else. It makes this statement independent of the operation of the earnings band mechanism and whether it is earning above or below its central approved ROE or above the upper earnings dead band. It makes it regardless of whether customer circumstances change, such as a child moving out, installing efficient appliances, or switching from electric heat to gas heat.

The only limit to its claim is if there is a "comparable reduction in the Company's retail cost of service / revenue requirement." But of course, it simultaneously claims that no action can reduce the embedded cost of service of its system, and that its tools and models do not allow it to perform said analysis about a cost of service reduction. Put together, any time

[48] STF-TAI-8-14.
[49] Id., emphasis added.

a customer reduces what they pay to GPC, GPC finds "as a matter of appropriate ratemaking principles" that **it should be able to charge everyone else to make up the difference**. As we have said, stunning in its scope and implications. If GPC's captive customers want to pay more money to the Company's shareholders, they can buy Southern Company stock. But they should not be forced to contribute to this excess through their bills.

Q40. IS THIS INTERPRETATION CONSISTENT WITH THE COMPANY'S OTHER TESTIMONY?

A40. Yes, it is. Company witnesses Legg, Evans, and Gattie repeatedly claimed that revenue erosion was a cost shift, even while admitting they never performed any cost of service analyses. The majority of Legg and Evans cost shift value was based not on monthly netting but rather on the structure of the R tariff. In fact, of the $1,356 cost shift the Company calculated, it claimed that $1,093 or 81% was actually based on the R rate design, with the monthly netting pilot's role diminished to "exacerbate[ing] this cost shift."[50]

The line of thinking clearly tees up GPC's position expressed in the discovery response: that it is entitled to any and all earnings that it can get under Commission-approved rates regardless of where it lies on the earnings band. It does not consider the central ROE value – currently set at 10.5% – and the corresponding rates designed to collect revenue at that level to be limiting. It clearly considers all revenue under the upper ROE dead band not as revenue that is it just able to keep, but revenue that it is entitled to. Nor does the Company consider the upper ROE dead band – currently set at 12.0% – to be limiting. In its arguments, it views the sharing mechanism as a sufficient guardrail. Any revenue erosion from one group of customers, even if it is already collecting revenues at a level that exceeds the upper dead band, "must be recovered" from other customers.

Q41. DO YOU AGREE WITH THIS INTERPRETATION?

A41. No. While we agree that GPC is *allowed* to keep money above its central ROE and the upper dead band, we do not believe that the Company is *entitled* to this revenue. Our view is that

[50] Evans and Legg Supplemental at 12.

the revenue requirement calculated at the central ROE represents the best and most appropriate value for profits. If the Commission truly believed that GPC was *entitled* to a 12.0% ROE, then it could have simply established a 12.0% ROE. But it did not do this; it established a 10.5% ROE paired with an earnings band mechanism as part of the multi-year rate plan structure. This is a critical distinction, and one that has major implications for both the requested $1.4 million RNR adjustment and the Company's arguments about cost shifts in general. Clearly, however, the Company sees this as a distinction without a difference.

Q42. WHY IS THIS DISTINCTION IMPORTANT?

A42. Because GPC is a regulated monopoly and for most of its customers, and all of its residential customers, there is no competitive alternative to the Company's electric service.[51] The Commission is charged with establishing fair, just, and reasonable rates that serve as a substitute for competitive markets.

A reasonable revenue requirement would include one that is calculated based on the central ROE set point. Given that GPC is only entitled to an opportunity to earn these revenues, it is hard to understand why it believes "appropriate ratemaking principles" would dictate that it "must recover" any and all revenue erosion at any point in its earnings band. To put numbers to this argument, in 2021 GPC collected $258.0 million more than what a 10.5% ROE would have dictated.[52] Here, it argues that it is entitled to collect another $1.4 million for RNR revenue erosion and push its surplus revenue to $259.4 million. The hubris in this claim is astonishing, particularly considering the massive, multi-billion dollar rate increase that it concurrently requests.

[51] The exception to this rule is an option for large commercial and industrial customers with more than 900 kW of peak demand to make a one-time, permanent election to take service from an electric coop. Customers under 900 kW of load and customer that have already selected GPC do not have this option. GA Code § 46-3-8

[52] 2021 Annual Surveillance Report.

III. GEORGIA POWER'S RNR QUANTITATIVE ANALYSES ARE FLAWED, NOT COST BASED, AND SHOULD BE REJECTED

Q43. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A43. We review the Company's quantitative analysis related to revenue erosion that it developed. This analysis supports the Company's recommendations that the RNR Monthly Netting program not be extended and that new RNR customers be required to take service on three-part rates.

Q44. PLEASE SUMMARIZE YOUR FINDINGS.

A44. The Company's analysis is methodologically flawed beyond repair, while also containing a glaring error discussed above that massively inflated its final cost shift value. The Company's choice to compress 1,100 RNR customers (which was already a subset and thus potentially not reflective of the total RNR population) into a mere four "representative" customers introduces errors that were only compounded when these four customers were expanded to represent 5,000. The Company makes no effort to validate whether its approach was robust, whether the four customers represented the group they were supposed to, or how several errors and questionable choices impacted its final results.

Q45. WHAT IS YOUR RECOMMENDATION ON THE COMPANY'S ANALYSIS?

A45. The Commission should give it no weight. Even after fixing the error, the study is simply not a cost-based analysis as required by the Commission. GPC's continue reliance on – and in fact substantial expansion of – revenue erosion arguments in place of cost of service analyses should not be validated. Instead, the Commission should consider the analyses that we put forth in Section VI below.

The Company's Analysis is Flawed, Uses Dubious Assumptions, and Discards Critical Data

Q46. PLEASE DESCRIBE THE GPC ANALYSIS RELATED TO RNR CUSTOMERS PERFORMED IN THIS PHASE OF THE RATE CASE.

A46. In the IRP docket earlier this year and in the first phase of this rate case, the Company produced an analysis that compared retail bills from customers on the RNR Monthly Netting and RNR Instantaneous tariffs. It calculated the difference between these two bills and labeled the delta as a "cost shift." We have discussed the flaws in this analysis extensively in both the IRP[53] and first phase of the rate case.[54]

In the second phase of this rate case, GPC presented a modified version of this analysis. It begins by analyzing 1,110 RNR Monthly Netting customers that had been in the pilot program for the full 12 months of 2021. The Company "gathered the metered readings (both delivered and pushed back energy) from 2021 as well as the installed panel capacities for each customer."[55] From this data, the Company estimated each customer's "usage before solar" through a methodology that was not described in discovery nor present in the initial workpapers submitted. These "pre-solar" usage levels were aggregated into quartiles based solely on annual energy use.[56]

The Company then calculated the average annual usage and system size of each quartile, again discarding any information related to seasonality and timing of usage. From here, the Company "selected four representative hourly loadshapes, ensuring that each sample closely matched the annual usage profile and did not have solar already installed behind-the-meter."[57] GPC then generated an hourly solar load profile for each of these four customers using PVWatts based the average quartile size system, and netted this against the non-solar load profile to create four "post-solar" hourly load profiles. These hourly load profiles were then run through the R and TOU-RD tariffs to calculate "before" and "after" bills for the four customers. Using these "insights", the Company expanded the results of the four customers to the full 5,000 RNR Monthly Netting pilot size to model the impact of the full pilot. The Company's analysis suggested that if all 5,000 customers were on the R tariff,

[53] GASEIA Intervenors IRP Direct at 39.
[54] GASEIA Intervenors Direct Section IV.
[55] STF-TAI-7-1 Revised.
[56] STF-TAI-7 Attachment A.
[57] STF-TAI-7-1 Revised.

there would have been $6.9 million in revenue erosion, with each customer causing a $1,377 annual "cost shift."[58]

Q47. WHAT IS YOUR IMPRESSION OF THIS ANALYSIS?

A47. Setting aside that nothing in this analysis is related to cost of service, and setting further aside the major error discussed above, the Company's methodology is fatally flawed and the entire analysis should be disregarded. The Company makes too many simplifying assumptions that render the final results non-representative of the data set. This applies in particular to the Company's decision to compress the 1,110 customers into four customers before expanding the four to represent 5,000 customers. Given the non-linear design of the R and TOU-RD tariffs, and the individual relationship between solar generation and household demand, one cannot simply condense and expand the sample set and expect to get meaningful results.

Q48. ARE THERE PARTICULAR CHOICES THAT YOU DISAGREE WITH OR MISTAKES YOU FOUND IN THE COMPANY'S ANALYSIS?

A48. Yes, there are myriad, listed below.

- **GPC fails to conduct the analysis at an individual customer level.** This is critical as net load is a function of both solar generation and household use, and bills are a non-linear function of net load. Averaging out 1,110 customers into four quartiles removes all the variation that is inherent in individual customer's usages.
- **GPC calculation of the "pre-solar" loads overstates generation and is not representative of the RNR customer group.** The Company was asked for "all data, studies and analyses" used in its analysis.[59] Nowhere in the initial round of workpapers did the Company demonstrate how it calculated the pre-solar loads. In a subsequent round of discovery, the Company provided its methodology, which was to simply assume that every PV system had a 16.3% capacity factor and a 120% AC to DC ratio.[60] These values are indicative of ideal, unshaded, south-facing roofs with insolation attainable in only some parts of the state. Applying this solar production to every RNR system overestimates how much solar is produced, which overstates the "pre-solar" values used in subsequent analyses.
- **GPC uses four non-solar customers as the basis for its entire analysis.** There is considerable risk in selecting only four customers to represent the entire RNR pilot program. No data about whether these customers are representative of the broader customer basis is provided. It is unknown whether they use electric or gas heating, whether they live in a rural or urban area, whether they use air conditioning or not, whether they have electric vehicles or

[58] STF-TAI-7 Attachment B.
[59] STF-TAI-7-1.
[60] STF-PAI-8-1 Attachment.

not, whether they work at home or not, whether they have medically necessarily equipment or not, whether they have kids or not, whether they went on an extended vacation or not. Each of these and many other factors impacts how customers use electricity. The Company did no analysis to show that these customers are in fact "representative" of the RNR population as a whole.

- **GPC did no analysis to justify how it selected the four "representative" non-participants.** GPC initially claimed that it "ensured that each sample closely matched the annual usage profile" of the quartiles of RNR Monthly Netting customers.[61] But no analysis was provided on how this selection was made. Did GPC cross reference these customers against monthly peak and off-peak usage or monthly peak demands of the 1,110 RNR customers? The Company did not provide workpapers despite being asked, so additional discovery was required. In follow up, the Company confirmed that "there is not a formal model or worksheet that would be considered to be 'analysis,'" and it only performed a perfunctory screen to ensure that the four customers were "in line with the annual usage targets from the RNR group."[62] No analysis of load shape, monthly usage, or peak/off peak usage was considered.

- **GPC incorrectly uses PVWatts data for single-year analysis.** PVWatts calculates solar generation based on a "typical meteorological year", which is an agglomeration of weather data from different years.[63] GPC then applied this generation to the 2021 usage of the four customers. There is a strong correlation between weather, solar generation, and customer usage; hot sunny summer afternoons lead to higher usage, but also produce more solar energy. GPC mixes apples and oranges, rendering the post-solar net loads non-representative of actual 2021 usage.

- **GPC erroneously fails to shift PVWatts generation to Daylight Savings Time.** PVWatts hourly data is presented in Standard Time. GPC's load data from the four customers is presented in Daylight Prevailing Time, as evidenced by the blank value for 2-3 AM on March 14, 2021, when clocks "sprang forward".[64] There is not a corresponding adjustment to PVWatts data, meaning that for most of the year between March and November, the solar generation is one hour earlier than the load data. This is meaningful as it increases the amount of solar available during late summer afternoon hours when loads are high.

- **There are anomalous values in the hourly meter read data for the four customers.** Reviewing the hourly data reveals values that unexpectedly spike to extremely high levels for one hour before returning to more typical usage.[65] For example, the customer representing the 2nd quartile has repeated spikes from 1 PM to 2 PM on days throughout the year when load increase from 2-3 kW to over 10 kW, before falling back rapidly. Even if these figures

[61] STF-TAI-7-1 Revised.
[62] STF-TAI-8-2, STF-TAI-8-3.
[63] PVWatts clearly includes the following disclaimer right next to the "Download Hourly Results" link: "* Caution: The PVWatts energy estimate is based on an hourly performance simulation using a typical-year weather file that represents a multi-year historical period for Atlanta, GA for a Fixed (open rack) photovoltaic system. The kWh range is based on analysis of a nearby data site described here. All of these results are based on assumptions described in Help that may not accurately represent technical or economic characteristics of the project you are modeling." https://pvwatts.nrel.gov/pvwatts.php
[64] STF-TAI-7-1 Attachment B.
[65] Id.

are accurate, it is highly unlikely that this load pattern is reflective of a broad set of customers.

- **GPC incorrectly scales results from four customers to all 5,000 customers.** In its workpapers, the Company expands the results from the four "representative" customers back to the 1,110 customer RNR Monthly Netting set as well as to a hypothetical set of 5,000 customers.[66] The Company provided no evidence that the 5,000 customers were sufficiently similar to the four representative customers to justify this expansion. The total "cost shift" also assumes all 5,000 customers would be residential customers, which is demonstrably false.
- **GPC conflates avoided energy savings and fuel savings in the presentation of its results.** In its testimony, GPC reports that customers only produce $21 in annual "avoided energy savings / benefits".[67] This value is calculated from the non-fuel variable O&M costs, but does not include the $254 in annual fuel savings that the Company itself identified.

Q49. GIVEN ALL OF THESE ISSUES, WHAT DO YOU RECOMMEND WITH REGARD TO THE COMPANY'S STUDY?

A49. We recommend the Commission give it little weight. Putting aside the major calculation error discussed above and the PVWatts daylight saving time error, the approach to condense 1,110 customers into four customers was done without sufficient consideration of the individual usage variation and the non-linear nature of rates. The Company admitted that it did not produce "a formal model or worksheet that would be considered to be 'analysis.'"[68] The subsequent decision to expand those four customers to represent 1,110 and 5,000 customers assumes the usage profiles are representative of the pilot customer base, a fact which the Company did not establish.

Just like when a pollster does not produce an accurate representative sample and the results of the election vary significantly from the polls, GPC did not demonstrate that its approach will lead to meaningful results. In total, the analysis's methodology is insufficiently robust to demonstrate the claims the Company makes.

[66] Id.
[67] Evans and Legg Supplemental at 12.
[68] STF-TAI-8-3

Revenue Erosion is a Rate Design Construct, not a Cost-of-Service Construct

Q50. HOW WOULD YOU CHARACTERIZE THE COMPANY'S VARIOUS RNR ANALYSES IN THE IRP DOCKET AND THIS RATE CASE DOCKET?

A50. They are clearly analyses based on revenue erosion from post-solar changes in usage when applied to retail rates. This is evident in every workpaper that the Company has provided on this issue, which calculates the bill reduction from lower usage after solar is installed.[69] They are clearly not cost-of-service based arguments that investigate how the actual load profiles and usage characteristics of RNR customers change after they install solar or how and when exported energy is sent to the Company's grid.

Q51. WHY IS THIS DISTINCTION IMPORTANT?

A51. For several reasons, most importantly is that the Commission directed the Company to produce "cost-based data" that parties could scrutinize. GPC has failed to do so, relying yet again on a revenue erosion argument that is answering a different question. It is also important to understand how a customer's usage of the grid changes after solar is installed. The Company complains that it is not collecting sufficient revenue from RNR customers to pay for grid costs, but at no point has it analyzed whether adding solar *actually* reduces the costs that RNR customers incur on the grid. It simply claims no reduction but offers no support for this position.

Q52. PLEASE BRIEFLY DISCUSS THE SCOPE AND PURPOSE OF A COST OF SERVICE STUDY.

A52. As described in the 1992 NARUC Electric Utility Cost Allocation Manual, "Generically, the prime purpose of cost of service studies is to aid in the design of rates."[70] A cost of service study ("COSS") is a method that maps the embedded or marginal costs of a utility's electric grid to the various customer classes based on those classes' characteristics and usage of the system. Assets and operating costs are functionalized based on their use (e.g., production,

[69] See e.g., the STF-DEA-3-37 workpapers from the IRP docket, the STF-TAI-1-27 workpapers from the first phase of the rate case docket, and the STF-TAI-7-1 Revised workpapers from the second phase of the rate case docket.
[70] Electric Utility Cost Allocation Manual January, 1992, National Association Of Regulatory Utility Commissioners at 13.

transmission, distribution, or customer), classified based on the utility service being provided (e.g., demand, energy, or customer), and allocated to customer groups based on usage of the system during certain key hours (e.g., coincident peak hours) or characteristics (e.g., number of customers or share of revenue). The result of the COSS is an accounting of costs incurred by, revenue collected from, and rates of return for each customer class.

Armed with this information, a utility may propose to increase or decrease the target revenue for classes that are under- or over-collecting relative to the Company's overall rate of return target. In this case, the Company presented its historic 2021 COSS showing that current rates produced an overall test year rate of return of 8.37% for the Company, with variations present in the various classes (Domestic – 7.25%, Small Business – 9.30%, Medium Business – 10.08%, etc.).[71] It also presented its future test year COSS showing that returns would fall under current rates, with an overall test year result of 6.27%.[72] This reduction in return is the basis for the Company's request for more revenue.

Q53. PLEASE BRIEFLY DISCUSS THE SCOPE AND PURPOSE OF RATE DESIGN.

A53. Once the cost of service for each class and rate of return has been established, the revenue requirement for each class can be calculated. This is the figure that will be collected through the retail rates if customers use electricity according to Company forecasts. The structure of these rates should be informed by the COSS process (i.e., they should reflect cost-causation principles) but must also incorporate other non-analytical considerations (e.g., gradualism, customer acceptance, avoiding rate shock, etc.).

Suppose for instance that a utility desires to collect $1 billion in revenue from its residential class. A utility can design any number of rates that will collect this revenue based on the billing determinants (e.g., the kWh of usage, the ratio of peak/off peak usage, the peak demand of customers, etc.). For instance, it can have a flat per kWh fee that divides $1 billion by the total kWh sold. It can have a customer charge that collects $100 million and

[71] Exhibit LPE-3.
[72] Exhibit LPE-1.

spread the rest over a volumetric rate. It can calculate usage during different time periods and establish a time of use ("TOU") rate where the sum of each TOU rate multiplied by the number of kWh in that TOU period equals the total revenue. There are literally unlimited ways in which rates can be designed to mathematically obtain the revenue requirement.

GPC has multiple residential rates, each of which has a different structure but are designed to be "revenue neutral" so that they would collect the same total revenue if every customer took service only on that rate. For instance, the R tariff uses a seasonally-differentiated block structure, with an inclining block in the summer and a declining block during non-summer months. The TOU-PEV rate has three volumetric time of use periods (peak, off-peak, and super-off peak). The TOU-RD rate has two volumetric time of use periods plus a demand component that charges based on the highest single hour of usage per month. These rates were at one time calculated to attain the same revenue requirement based on the total residential class's usage patterns.[73]

Q54. DOES THE REVENUE COLLECTION RESULTS OF A RATE DESIGN CHANGE THE UNDERLYING COST OF SERVICE OF CUSTOMERS TAKING SERVICE ON THOSE RATES?

A54. No, it does not. Cost of service is a function of a group of customer's usage of the system. It incorporates characteristics such as total energy use, timing of energy usage, usage during peak demand hours, and so on. These characteristics impact how the system needs to be designed to meet customer loads; customer groups that use more power during on peak hours contribute more to production costs than groups that use less power during peak hours. Similarly, customers that use more power overnight when there is spare capacity put less demand on the system and have a lower cost of service.

These characteristics are separate and distinct from revenue collected through different ratees. For example, suppose a utility had a rate where every customer paid a fixed $100 fee every month regardless of how much and when they used electricity. A customer

[73] We use the caveat because it is unclear when the last time the Company updated its billing determinants and rate design to ensure that the various tariffs remain revenue neutral. Our analysis in phase one of this rate case suggested the TOU-RD rate substantially over-collected revenue compared to other tariffs.

that only uses energy during non-peak hours would pay the same as a customer that only uses energy during peak hours, even though the former has a lower cost of service than the latter. Further, if the customers change their behavior, such that the former uses more energy on peak and the latter uses more energy off peak, the revenue collected on this rate does not change even though these usage changes impact the cost of providing service to the customers.

Q55. HAVE OTHER COMMISSIONS ADDRESSED THE DISTINCTION BETWEEN COST OF SERVICE AND REVENUE EROSION / RATE DESIGN?

A55. Yes. Michigan has a statute that requires export compensation for BTM systems to be cost-based.[74] DTE Energy ("DTE"), a regulated Michigan utility, proposed to implement a grid access charge for solar customers that was predicated on a supposed cost shift that led to a revenue deficiency from BTM DG customers.[75] This is the exact type of argument made by the Company in this case. The Michigan Public Service Commission rejected DTE Energy's argument, finding the grid access charge "is neither COS-based, as required by MCL 460.6a(14), nor equitable. As ELPC noted, the utility's method for calculating the [grid access] charge explicitly relied on the distribution revenue deficiency and not on any cost to serve."[76] While Georgia does not have a similar statute regarding cost-base export rates for BTM DG customers, it is instructive that another utility commission reviewed and rejected claims that a rate design / revenue erosion argument for BTM DG customer was compatible with a statutory requirement for cost-based rate setting.

[74] MCL 460.6a(14) "Within 1 year after the effective date of the amendatory act that added this subsection, the commission shall conduct a study on an appropriate tariff reflecting equitable cost of service for utility revenue requirements for customers who participate in a net metering program or distributed generation program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211."
[75] Qualifications and Direct Testimony of Neal T. Foley on behalf of DTE Energy, Case No U-20836.
[76] Michigan Public Service Commission Order at 198, Case U-20162, May 2, 2019 (internal citations omitted).

IV. GEORGIA POWER'S RNR POLICY ANALYSIS IS NOT APPLICABLE TO GEORGIA AND SHOULD BE REJECTED

Q56. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A56. In this section, we review the Company's policy arguments against expanding the RNR Monthly Netting program. These include a claim that other states are rapidly retreating from net metering policies and because of that, the Commission should not approve any expansion of the RNR Monthly Netting program. We also discuss the Company's proposal to require new RNR customer to take service on three-part rates as a condition of joining even the RNR Instantaneous program. Finally, we clarify some confusion that arose during the Company's RNR hearing related to the Inflation Reduction Act ("IRA").

Q57. PLEASE SUMMARIZE YOUR FINDINGS.

A57. The Company's policy argument about states "walking away" from net metering is unsupported. In fact, net metering remains the law of the land in most states and investing in residential and small commercial BTM solar creates jobs and brings investment to the state. Further, states that have made changes away from traditional net metering have landed on export structures and rates that are far more favorable than GPC's RNR Instantaneous program. The proposal to mandate demand-based rates must be rejected as discriminatory. The Company's main support for this – its revenue erosion analysis – is fatally flawed and contains a major error that undermines its conclusion. The IRA has the potential to be transformative to the solar industry, but some of its policies will take time to implement. Further, several of the expanded incentives are only available to commercial taxpayers, not residential customers. State policy support remains critical to grow BTM markets, particularly in the short term when several headwinds persist.

Q58. WHAT IS YOUR RECOMMENDATION ON THE COMPANY'S POLICY ARGUMENTS?

A58. We recommend the Commission recognize the myriad benefits that BTM solar brings to Georgia. In addition to helping customers control their bills in a time of rising prices, it creates jobs and investment in the state while supporting local businesses. The Company's

arguments about states retreating from net metering are overblown and do not reflect the reality of the market. The Commission should reject the proposal to mandate service on the TOU-RD rate, even if it is redesigned as we recommended. Customers should be able to choose what tariff they wish to take service on independent from their choice to install solar.

Increasing the RNR Monthly Netting Program will Lead to Investment and Jobs in Georgia

Q59. HOW DOES GEORGIA RANK IN TERMS OF RESIDENTIAL SOLAR DEPLOYMENT?

A59. Georgia ranks very low on residential rooftop solar. In terms of absolute capacity deployed, Georgia ranks 39th with about 54 MW of residential solar.[77] By contrast, North Carolina and South Carolina have deployed 280 MW and 255 MW, respectively, and Florida has installed 1,360 MW. On a per capita basis, Georgia fares even worse, ranking 47th with only 5 watts per customer. This is roughly 1/5th the per-capita value of North Carolina, 1/10th the per-capital value of South Carolina, and 1/12th the per-capita value of Florida.

[77] Values in this paragraph are for Georgia as a whole, not just GPC's territory. Rankings include Washington DC and Puerto Rico. Data from SEIA/Wood Mackenzie U.S. Solar Market Insight Q3 2022, U.S. Census Bureau. Full values available in GASEIA Supplemental Exhibit 1.

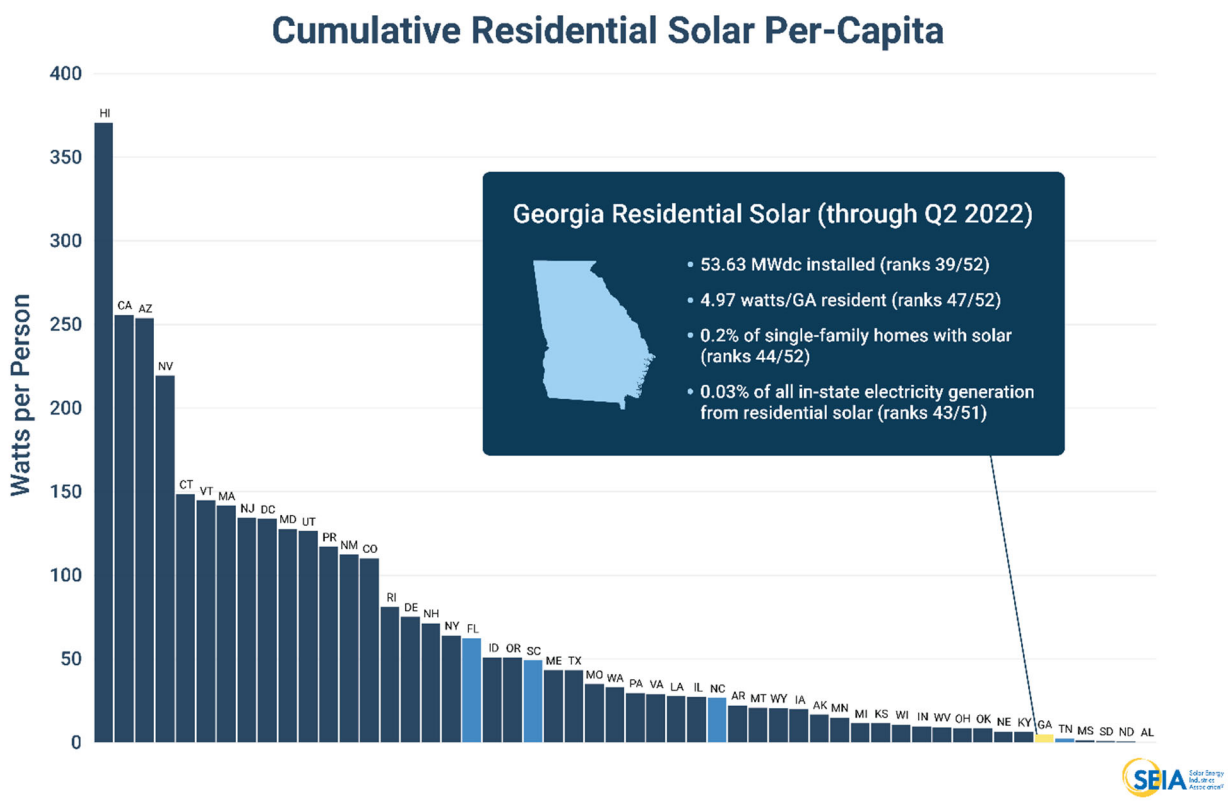


Figure 2 - Georgia Residential Solar Per-Capita

Q60. DO SMALL-SCALE PV SYSTEMS LEAD TO INVESTMENT AND JOBS IN A STATE?

A60. Definitively yes. Georgia's solar market has been dominated by large-scale PV systems, which have stood up a sizable solar industry in the state. However, Georgia's relative dearth of small-scale systems means that it employs fewer people and has had less solar investment in the state's economy than other similarly sized markets.

We reviewed job and economic investment figures from Georgia, Arizona, Nevada, and New Jersey.[78] Each of these states have installed roughly similar amounts of solar, but the sector breakdowns vary significantly, as seen in Figure 3 below. Georgia is almost entirely utility-scale solar ("USS") with very small contributions from community solar ("CSG"), non-residential ("C&I"), and residential ("Res"). By contrast, each of the other

[78] Capacity data from 2022 Q3 Solar Market Insights, jobs and investment data from SEIA's webpage at https://www.seia.org/states-map

states has significantly larger non-USS sectors, with Arizona having the largest residential and New Jersey having the most non-residential installs.

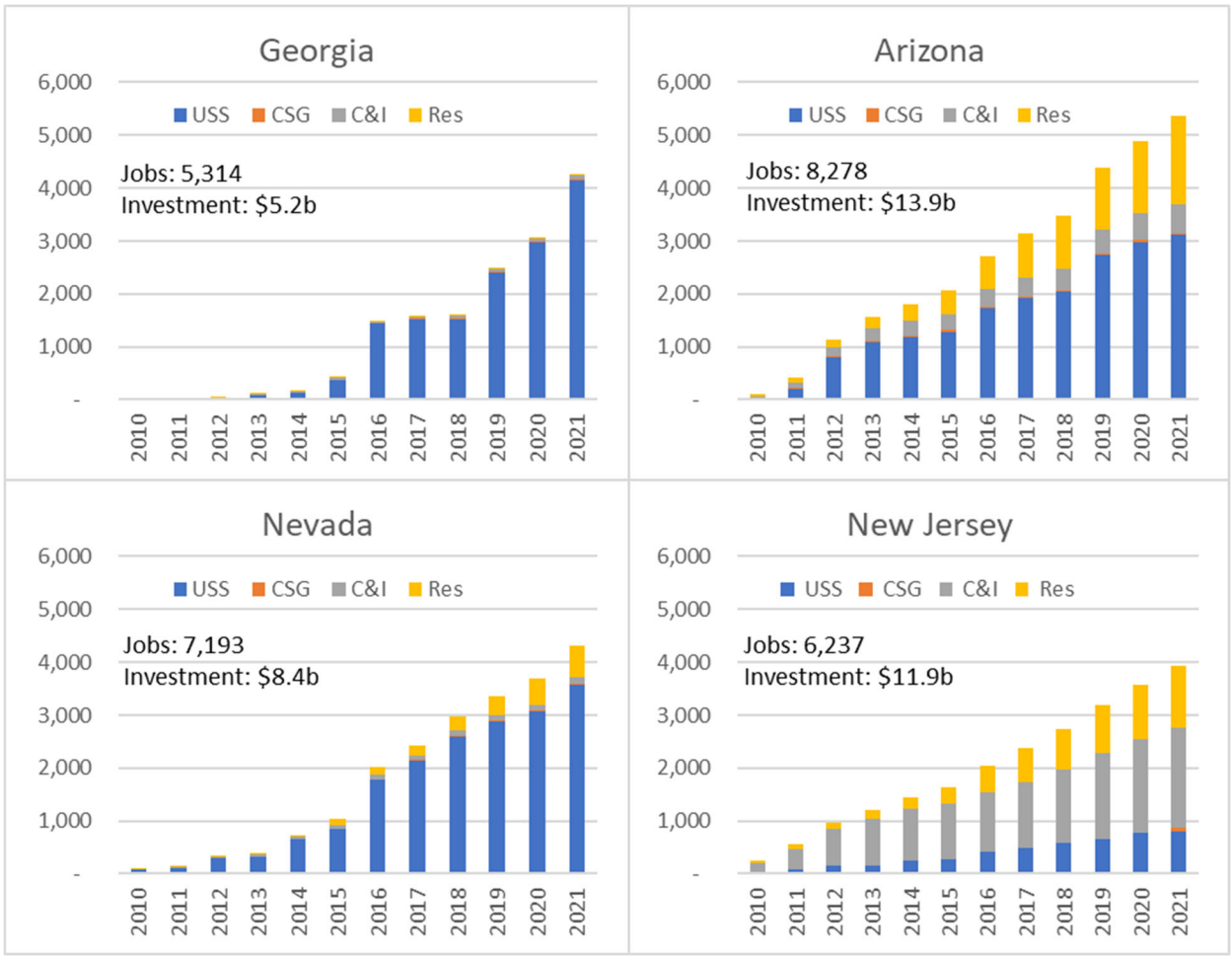


Figure 3 - Capacity, Jobs, and Investment of Selected States

The jobs and economic investment figures are telling. Georgia ranks last in each of these categories, with roughly 1,000, 2,000, and 3,000 fewer jobs than New Jersey, Nevada, and Arizona, respectively. Its solar industry investment of $5.3 billion is substantially lower than the other states, and barely more than a third of Arizona's $13.9 billion.

Q61. WHY IS THERE SUCH A LARGE DIFFERENCE IN THESE FIGURES BETWEEN THE STATES?

A61. It is primarily because small-scale residential and commercial solar systems require more investment and labor on a per-unit basis than USS. However, unlike large USS solar facilities that are put into rate base or paid through a power purchase agreement ("PPA")

which ultimately requires GPC's customers to pay for the system, capital costs for small solar facilities are paid through the private capital of the system's owners. These costs are not recovered through rate base, and GPC does not earn a profit on them.

Similarly, small-scale systems require more labor per unit of capacity than USS systems, so 1 MW of BTM solar will support more job creation than 1 MW of USS solar. Data from the 2021 Solar Jobs Census[79] shown below in Table 2 shows the magnitude of this difference by sector; residential systems support 10 times as many jobs per MW than USS systems.

Segment	Installation and Project Dev Jobs	2021 MW Installed	Jobs / MW
Residential	85,305	4,252	20.1
C&I	34,329	1,492	23.0
Community Solar	15,517	1,187	13.1
Utility-scale	33,808	17,164	2.0

Table 2 - Installation and Project Development Jobs by Sector

Q62. DOES THIS DATA SUGGEST THAT GEORGIA SHOULD STOP BUILDING LARGE-SCALE SOLAR PROJECTS?

A62. Of course not. The Commission's and Company's support of large-scale solar projects has been critical, and efforts should redouble to bring even more USS solar on online. However, by stunting the residential and commercial sectors, Georgia is missing out on a massive opportunity for job growth and investment in the state's economy, much of which may be captured by locally owned and operated companies.

It is also important to not consider the added investment as the "cost" of the new jobs. Rather, the added investment is more money pumped into Georgia's economy, largely supported by private capital and not ratepayer funds. Georgia will get more investment and new jobs as it expands its BTM market.

[79] https://irecusa.org/programs/solar-jobs-census/

Other States that are "Walking Back" Net Metering Still Have More Generous Policies than Georgia

Q63. HOW DID GPC FRAME THE STATE OF THE MARKET WITH RESPECT TO NET METERING?

A63. GPC was quite explicit on its framing of this issue, stating:

> States that have led the way in adopting aggressive net metering strategies as a means to achieve their energy policy goals are now walking back or reevaluating net metering policies, on account of significant negative externalities and issues of ratepayer fairness… I would conclude it is near universally accepted that monthly net metering at the retail rate is no longer the preferred policy option, even in states with aggressive decarbonization and energy transition targets."[80]

Q64. DID THE COMPANY PROVIDE SUPPORT FOR THIS POSITION?

A64. No, it did not. Its testimony in this section referred to a few states that have moved from conventional kWh-based net metering to net billing constructs, such as California, Indiana, Kentucky, and Utah.[81] This is hardly a universal survey of state policy positions.

Q65. DO YOU HAVE ANY INSIGHT ON THE CURRENT STATE OF NET METERING IN THE US?

A65. Conventional net metering remains the law of the land in many states. While it is true that some states such as those listed above are transitioning to post-NEM structures, most of the country continues to utilize net metering as the default. In fact, as of spring 2022, 33 states continue to offer net metering in some form as shown in Figure 4 below.

[80] Gattie Supplemental at 6, 16.
[81] Gattie Supplemental at 17.

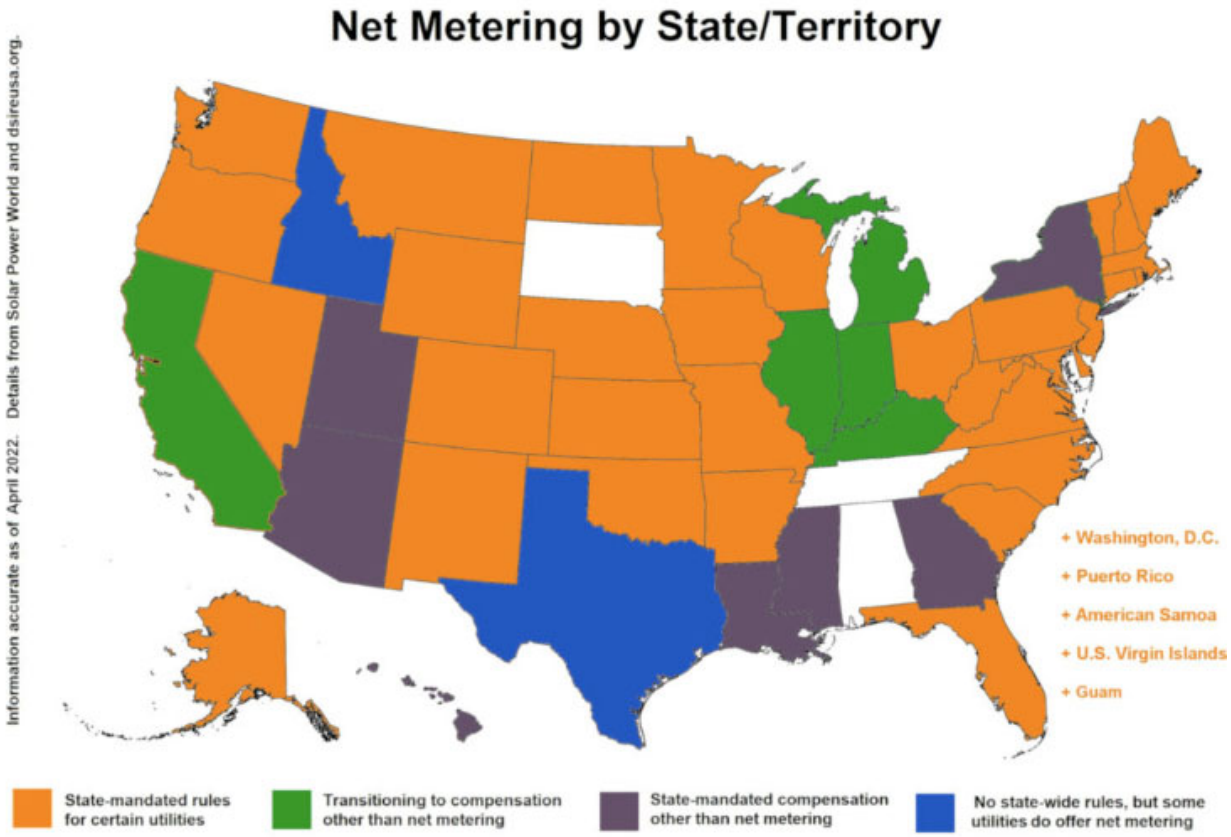


Figure 4 - Net Metering Policy State Map

Q66. DID THE COMPANY PROVIDE ADDITIONAL INFORMATION TO SUPPORT ITS POSITION?

A66. Yes. In discovery, the Company provided additional information on states that it says demonstrated a "walking back" of net metering policies. These included Indiana, Arizona, Kentucky, New Hampshire, Utah, and California.[82] Most of the responses discussed shifts from traditional kWh-based net metering to net billing constructs with lower-than-retail credit for exported energy. However, when one looks at the actual policies that these states implemented, they turn out to be more generous than the one that GPC currently uses.

Table 3 shows the program characteristics for these states, including the netting period (e.g., instantaneous or monthly) and exported energy credit rate. GPC's RNR Instantaneous program is also shown for comparison.

[82] STF-TAI-8-20.

State	Netting Period	Current Export Credit ($/kWh)	Notes
Georgia	Instantaneous	$0.034	
Arizona[83]	Instantaneous	$0.08465	Rate locked for 10 years
Indiana[84]	Instantaneous	$0.045712	125% wholesale LMP
Kentucky[85]	Monthly	$0.09746	Value of Solar calculation
New Hampshire[86]	Monthly	$0.179 up to monthly usage $0.14 in excess of monthly usage	100% of energy and transmission + 25% of distribution
Utah[87]	Instantaneous	$0.04462 (winter) $0.05160 (summer)	
California[88]	Instantaneous	Varies by hour, avg is ~$0.085	Locked in for 9 years

Table 3 - Net Billing Rate Comparison

Every one of the examples that the Company pointed to has net billing policies that are far more beneficial for customers than GPC's. Even with the recently updated GPC avoided costs, the closest state on this list has a credit that is more than a third higher. Several of these states have export rates in the $0.08 - $0.10 per kWh range, while New Hampshire credits customers with 100% of production costs, 100% of transmission costs, and 25% of distribution costs. Even California's major reform provides an opportunity for customers with solar plus storage to earn sizable export credits by managing their batteries effectively. The values vary by hour and month, but export credits in excess of $0.30/kWh are possible.

Q67. WHAT ARE YOUR CONCLUSIONS ON THIS COMPONENT OF GPC'S POLICY ARGUMENT?

[83] https://www.aps.com/-/media/APS/APSCOM-PDFs/Utility/Regulatory-and-Legal/Regulatory-Plan-Details-Tariffs/Residential/Renewable-Plans-and-Riders/rcp_RateSchedule.ashx?la=en https://www.aps.com/-/media/APS/APSCOM-PDFs/Utility/Regulatory-and-Legal/Regulatory-Plan-Details-Tariffs/Residential/Renewable-Plans-and-Riders/rcp_RateSchedule.ashx?la=en

[84] https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/electric-rates/2020-current-rates/table-of-contents/rider-889.pdf https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/electric-rates/2020-current-rates/table-of-contents/rider-889.pdf

[85] https://psc.ky.gov/agencies/psc/press/052021/0514_r01.pdf https://psc.ky.gov/agencies/psc/press/052021/0514_r01.pdf

[86] https://www.solarreviews.com/blog/new-hampshire-net-metering https://www.solarreviews.com/blog/new-hampshire-net-metering

[87] https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/utah/rates/137_Net_Billing_Service.pdf https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/utah/rates/137_Net_Billing_Service.pdf

[88] https://www.ethree.com/tools/acm-avoided-cost-model/ https://www.ethree.com/tools/acm-avoided-cost-model/

A67. A65. We find it unconvincing. First, most states in the country continue to offer traditional net metering. Far from walking away, some states are actually expanding the policy, such as Maryland which recently passed legislation to expand net metering from 1,500 MW to 3,000 MW (against a state-wide peak demand that is actually smaller than GPC's peak demand).[89]

Second, the Company's list of states that are supposedly "walking away" from net metering are reaching a policy destination that is either somewhat or dramatically more favorable to BTM solar customers than GPC's RNR instantaneous program. With the exception of Kentucky and Indiana, which have not developed much of a rooftop solar market, the other states on the list considerably exceed the rooftop capacity of Georgia, suggesting they maintained their traditional net metering structures while the market matured.

GPC's Rate Comparison Fails to Analyze Bills, and Georgia's are High

Q68. HOW DID GPC'S WITNESSES DISCUSS GEORGIA'S DECISIONS ABOUT ENERGY POLICY?

A68. Dr. Gattie described Georgia's energy policy decisions related to the integration of renewable energy as "measured and practical", and then described how this differed from other states such as California and Texas. According to Dr. Gattie, "California is prioritizing carbon reduction, which has resulted in one of the lowest carbon footprints in the country, but also some of the highest electricity rates with regular threats of blackouts and power shortages" while "Texas, which is optimizing its power sector for lowest rates—and indeed has affordable rates—[] has experienced severe reliability issues the past two years."[90]

Dr. Gattie then opines that because of Georgia's measured approach where it has "prioritized reliability, affordability, and resource diversity", it has maintained low rates while developing renewables and reducing its carbon intensity.[91] He then produced a series of charts that showed Georgia's residential rates in comparison to other states, including

[89] https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0407?ys=2021RS,https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0407?ys=2021RS. Maryland's net peak demand is about 13,000 MW, while GPC's 2021 peak was about 16,200 MW.

[90] Gattie Supplemental at 18.

[91] Gattie Supplemental at 19

those in restructured markets and those with the top 8 highest GDPs in the country. Dr. Gattie's conclusion was that due to Georgia's approach, Georgia had low residential rates compared to other high-GDP states and was competitive with restructured markets.[92]

Q69. DO YOU DISAGREE WITH DR. GATTIE'S CLAIMS?

A69. We do not dispute the figures he produced, but we do believe his commentary is overstated. For instance, he clearly implies that California's focus on decarbonization has led to reliability challenges and high rates. In reality, California's reliability issues have been exacerbated in recent years by utility negligence[93] and wildfires driven by worsening climate change.[94] Likewise, Texas's problems during the winter storm a few years ago was caused in large part by its electric and gas industry regulators failing require generators to winterize their equipment, despite having been warned about the potential risk years before after a bad storm in 2011.[95]

Q70. DO CUSTOMERS PAY THEIR BILLS IN RATES OR IN DOLLARS?

A70. Customers pay their bills in dollars. While electric rates are important, particularly for large commercial and industrial customers for whom electricity can be considered a cost of production, residential customers care about their total bills. In this regard, Dr. Gattie's analysis of residential rates is the wrong metric on which to focus. When one instead compares residential bills between the various states in the country, Georgia does not look as competitive.

Q71. PLEASE EXPLAIN.

A71. We pulled data using the same Energy Information Administration ("EIA") data as Dr. Gattie, but instead of simply reporting residential rates, we calculated the annual bills that residential customers paid under those rates. In this light, Georgia is not as competitive, as seen in Figure 5 below. Residential bills have been between the 7th highest and 14th highest,

[92] Gattie Supplemental at 21.
[93] https://www.npr.org/2020/03/23/820293479/pg-e-will-plead-guilty-to-84-counts-of-involuntary-manslaughter-during-2018-wild
[94] https://ww2.arb.ca.gov/wildfires-climate-change
[95] https://www.texastribune.org/2021/02/17/texas-power-grid-failures/

with an average ranking of 10th, between 2008 and 2021, the dates for which EIA has the requisite monthly information to calculate these values.

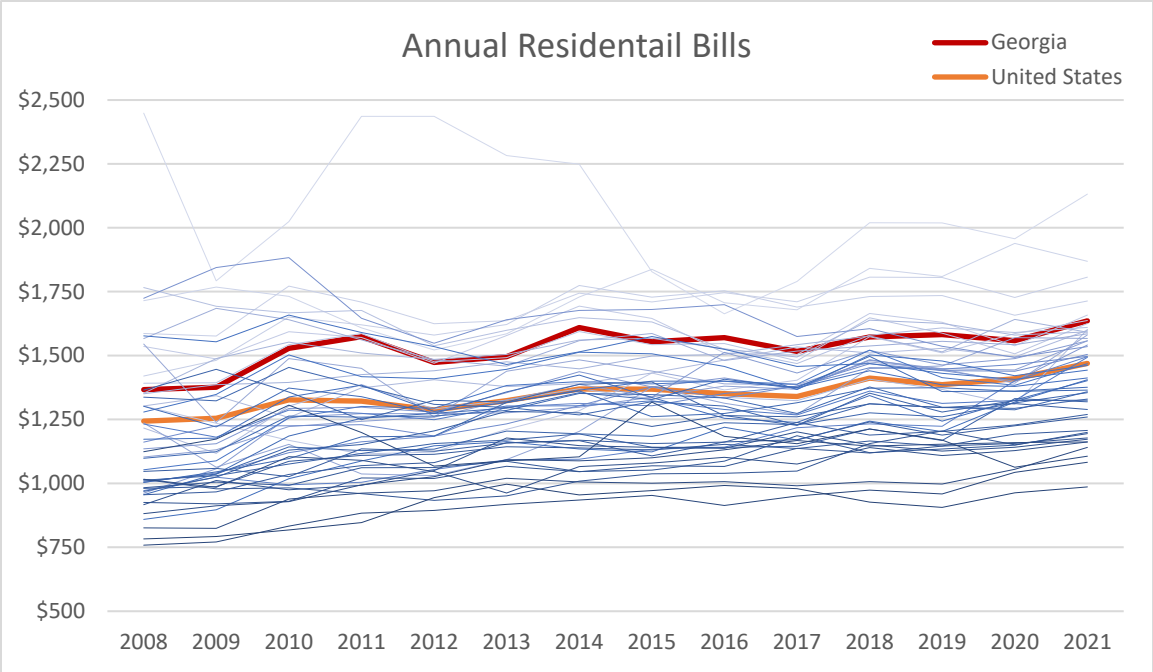


Figure 5 - Comparison of Residential Bills

When compared to other regulated markets, Georgia fares worse yet as shown in Figure 6 below. Residential bills range between 3rd highest and 8th highest, with an average rank of 5.3 since 2008. In fact, in 2021, Southern Company nearly earned an unenviable trifecta, with Alabama, Mississippi, and Georgia having the 1st, 3rd, and 4th highest residential bills among regulated markets.

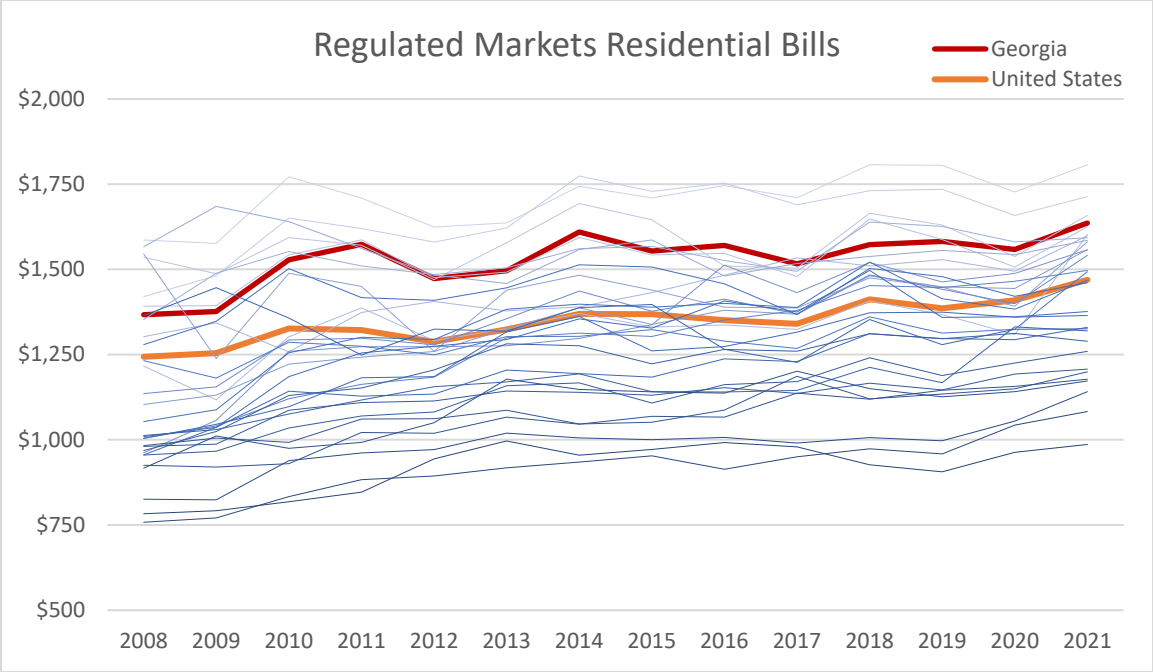


Figure 6 - Regulated Markets Residential Bills

Finally, we reproduced Dr. Gattie's graph for the top eight GDP states. In his version, Georgia had rates that were at or near the bottom of the list. Unfortunately, customers who pay bills in dollars did not see this benefit as seen below in Figure 7. Georgia residential bills were consistently near the top of the bunch, ranking no lower than 3rd and grabbing the top or second spot in 8 of the past 9 years. The typical Georgian would have paid $5,330 more since 2008 (nearly $400 more per year) than the typical Californian, a sizable 33% premium.

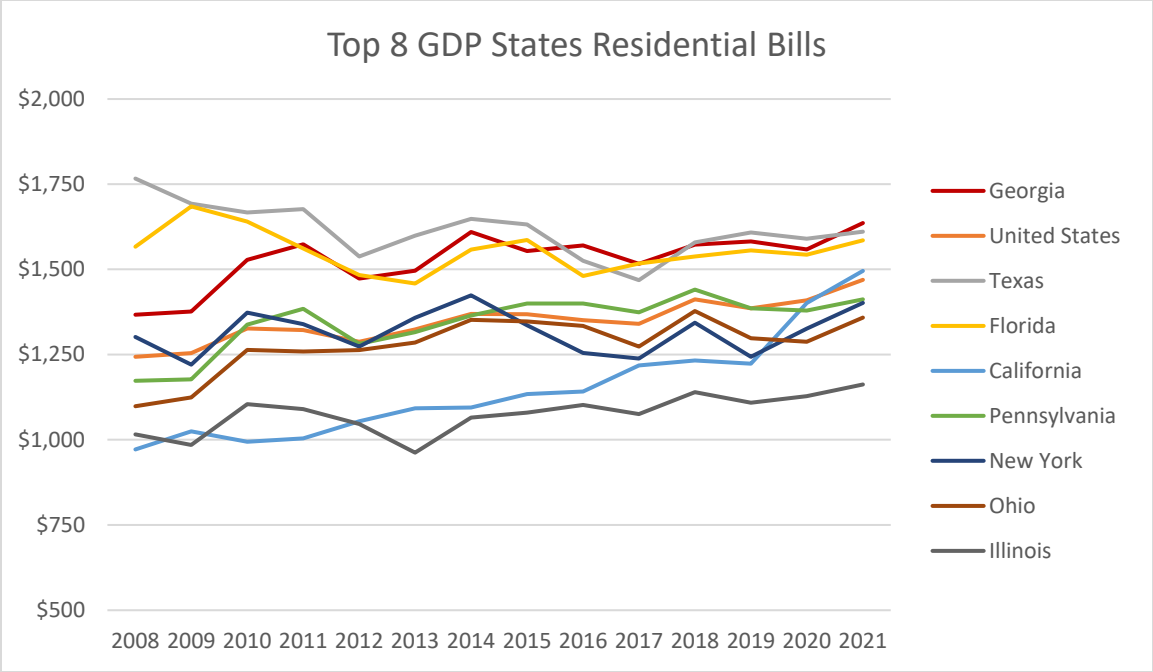


Figure 7 - Top 8 GDP States Residential Bills

Q72. IS THIS ISSUE PARTICULARLY ACUTE FOR LOW-INCOME CUSTOMERS?

A72. Yes, it is. A 2019 U.S. Department of Energy report came to the exact same conclusion regarding low-income household energy burden:

> In the five states with the highest low-income energy burden— Mississippi, South Carolina, Alabama, Georgia, and Arkansas— low-income households use 36% more electricity than the low-income national average. In these states, electricity is the dominant heating fuel and high air conditioning demand also contributes to high consumption. These factors contribute to the relatively high total energy burden, despite households paying lower prices per kilowatt of electricity.[96]

Q73. WHAT IS YOUR CONCLUSION ABOUT DR. GATTIE'S ANALYSIS OF RATES?

A73. We find it misleading at best. While it is accurate that Georgia historically has had relatively low residential rates, its customers still face high bills. Residential customers – particularly low- and moderate-income customer – don't care about how high their rate is, they care about how high their bill in. And Georgia residential bills are high – and going to get even higher if GPC's proposed rate increases are approved.

Q74. WHAT ARE YOUR CONCLUSIONS REGARDING THIS ELEMENT OF GPC'S TESTIMONY?

[96] Low-Income Household Energy Burden Varies Among States – Efficiency Can Help in All of Them. https://www.energy.gov/sites/prod/files/2019/01/f58/WIP-Energy-Burden_final.pdf

A74. We believe that Dr. Gattie's focus on rates rather than bills is inappropriate for the residential sector he analyzes. Despite lower-than-average rates, GPC customer use more electricity than average and thus pay higher bills. Georgia's residential electricity bills are frequently in the top 10 in the country and even higher compared to regulated states. And all of this is before the hundreds of dollars of requested rate increases, Plant Vogtle costs, and deferred fuel balance expenses hit their wallets.

Requiring RNR Customers to Take Service on Demand-Based Rates is Discriminatory and Must be Rejected

Q75. ARE THERE CURRENTLY ANY RESTRICTIONS REGARDING THE RESIDENTIAL TARIFF THAT A CUSTOMER MUST TAKE SERVICE UNDER TO QUALIFY FOR THE RNR PROGRAM?

A75. No. A residential customer may take service under any of the residential tariffs and participate in the RNR program.

Q76. DOES THE COMPANY PROPOSE TO CHANGE THIS?

A76. Yes. It proposed that all new RNR customers who move to the tariff on or after January 1, 2023, must take service on a three-part rate with a demand charge.[97] For residential customers, the only such tariff is the TOU-RD rate. In the Company's view, three-part rates "better align with the Company's underlying costs, and further mitigate the cost shift between participating and non-participating customers."[98]

Q77. DO YOU AGREE WITH THE COMPANY ON THE GENERAL POINT ABOUT THREE-PART RATES?

A77. No. As discussed extensively in our direct testimony, demand-based rates in general and the TOU-RD rate in particular is a terrible fit for residential customers.[99] While we did not recommend eliminating this tariff as it was voluntary, we did recommend the Commission require a major redesign, ensure it was revenue-neutral with respect to the R tariff, and prevent it from being the default residential rate.[100]

[97] Evans and Legg Supplemental at 14.
[98] Id.
[99] See e.g., GASEIA Intervenors Direct at Section V.
[100] Id. at 105.

Q78. DO YOU AGREE WITH THE SPECIFIC POINT ABOUT REQUIRING RNR CUSTOMER TO TAKE SERVICE ON A THREE-PART RATE, WHICH FOR RESIDENTIAL CUSTOMERS WOULD BE THE TOU-RD RATE?

A78. Absolutely not. Requiring a group of customers to take service on a particular rate as a condition for installing solar is discriminatory. Georgia statue prevents all electricity suppliers from "having or applying any rate, charge, or service rule or regulation which unreasonably discriminates against or in favor of (1) any member of a class of consumers as opposed to any other consumer who is or should be in the same class of consumers for such purposes, or (2) any class of its consumers as opposed to another class of consumers for such purposes."[101]

While we are not attorneys and are not offering a legal opinion, imposing a mandatory rate on a member of the residential class that wishes to install solar is clearly against the plain reading of the statutory text. Nowhere in the case has GPC argued that RNR customers should be treated as a separate customer class, and even if it did, it would still run into issues with discriminating against an entire class of RNR customers.

As it currently exists, the TOU-RD rate is a bad fit for pretty much all customers that are not structurally benefitted by demand-based rates.[102] We showed that 90% of customers with usage below the median were charged more on the TOU-RD rate than the R rate.[103] Even if the rate were to be redesigned, it would still be improper to require RNR customers to take service on only one rate. It runs antithetical to the notion of optionality and customer choice in addition to being discriminatory.

Q79. HAS ANOTHER STATE TESTED THIS APPROACH OF MANDATING BTM PV CUSTOMERS TAKE SERVICE ON A THREE-PART RATE?

[101] GA Code § 46-3-11
[102] For example, residential customers that consume very high amounts of energy tend to save money on revenue-neutral demand rates as they have higher load factors than lower-use customers. Even without changing their behavior or managing their demand, these customers are likely to save money on the TOU-RD rate.
[103] GASEIA Intervenors Direct at 59.

A79. Yes. The Kansas Corporation Commission ("KCC") approved a mandatory demand-based rate for solar customers for Evergy. The KCC was sued, and eventually the case was heard by the Kansas Supreme Court. In its ruling overturning the KCC's decision, the Kansas Supreme Court found that the mandatory demand rate was "simply price discrimination" and remanded the case back to the KCC.[104] The KCC then ordered that DG customers take service on rates that were identical to standard residential rates.[105]

Q80. IS GPC AWARE OF ANY UTILITY THAT REQUIRES SOLAR CUSTOMERS TO TAKE SERVICE ON THREE-PART RATES?

A80. No, it is not. The Company did note that its sister company Alabama Power requires residential customers to take service on one of three rate options, one of which is their newly approved demand-based rate.[106] But even in this example, customers are not required to take service on demand-based rates.

Q81. AND HOW IS ALABAMA RATED IN THE COUNTRY ON PER-CAPITAL RESIDENTIAL SOLAR CAPACITY?

A81. It is dead last.

Q82. WHAT IS THE BASIS FOR GPC'S PROPOSAL TO SHIFT CUSTOMER TO A DEMAND-BASED TARIFF?

A82. It is to avoid what the Company claims is a major cost shift caused by customer self-consuming energy on the R tariff.[107] Separate from the question of RNR Monthly Netting, which is a post-hoc adjustment applied to customers' bills, the Company analyzed the bill reductions that RNR customers receive from self-consuming energy generated from their solar facilities. The Company calculated that nearly $1,100 a year per RNR customer was "shifted" to non-RNR customers due to the R rate design.

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[104] *In the Matter of the GASEIA Application of Westar Energy, Inc. and Kansas Gas and Electric Company*, 311 Kan. 320,330 (2020).
[105] Kansas Corporation Commission Order, Docket No. 18-WSEE-328-RTS.
[106] The demand rate in question is actually worse than the TOU-RD rate as it has a demand ratchet that bills customers a minimum of 90% of their highest on-peak hour in the previous year. In other words, just one slip during peak hours, and the demand portion of the bill will never be less than 90% of that month for the next year!
[107] Legg and Evans Supplemental at 14.

Q83. WAS THIS THE FIGURE THAT YOU DISCUSSED EARLIER THAT HAD A MAJOR ERROR IN THE CALCULATION?

A83. Yes. As it turns out, the Company's workpapers contain a glaring error that, when fixed, reduced the $1,093 per year figure to $560 per year. The Company's own calculation suggests that the TOU-RD rate still has a $254 per year cost shift embedded in it, meaning that instead of being $839 higher per year, the R rate is instead only $305 higher per year. While we do not endorse the Company's analysis for a host of other reasons, the one line of support it offered for require three-part rates was effectively cut down.

Q84. EVEN CONSIDERING THE CORRECTED VALUES, DO YOU AGREE THAT THE "COST SHIFT" FROM SELF-CONSUMED ENERGY EXISTS AND JUSTIFIES A REQUIREMENT TO TAKE SERVICE ON THREE-PART RATES?

A84. No. The mere fact that the Company claims a "cost shift" occurs from self-consumed energy is very troubling. This argument has nothing to do with exported energy and nothing to do with monthly netting. RNR customer pay GPC full retail for every kWh consumed from the grid. The fact that they have an alternative source of supply for some portion of their electric load is irrelevant.

Customers are under no obligation to purchase a certain amount of energy from the Company. If they want to install a spa and heat it with electricity, the Company will provide that power and the customer will pay for it. If the next owner of the house removes the spa, there is no expectation that the new owner will continue to pay for something they are not getting from GPC. Similarly, if a customer replaces old, inefficient air conditioners with new heat pumps and reduces their summer load by 50%, there is no obligation to continue paying GPC based on the quantity of energy they used to use.

GPC is trying to break the cardinal rule that "what happens behind the meter stays behind the meter." The Company has no business meddling in how much a customer consumes, whether they change their usage patterns, or what technologies a customer uses meets their loads. Claiming that customers that reduce their usage are somehow creating a

cost shift that must be recovered from other customers is an extreme position and should not be accepted by the Commission.

Q85. WHAT DO YOU RECOMMEND WITH RESPECT TO THIS ISSUE?

A85. The Commission should reject the Company's proposal to require RNR customers to take service on three-part rates as discriminatory. They should be able to take services on whatever tariff they wish as long as it is currently eligible for the RNR program. The Commission should also confirm that residential customers have the unilateral right to reduce their usage through any means without triggering a "cost shift" that must be collected from other customers.

The IRA Will be Helpful to BTM Solar, but Headwinds Remain

Q86. WHAT WAS ANOTHER POLICY ARGUMENT ADVANCED BY THE COMPANY AGAINST EXPANDING THE RNR MONTHLY NETTING CAP?

A86. The Company argued that the recently passed Inflation Reduction Act ("IRA") would provide substantial support to the industry and that the best course of action is to wait to see how that play out. As expressed by Dr. Gattie, "Given the generous benefits provided by the IRA and Georgia's proven track record in developing these resources, I conclude that further ratepayer investments are not needed to encourage this growth, and additional subsidies would likely result in nothing more than additional windfall payments to solar installers and developers on the backs of other ratepayers.[108]

Q87. DID. DR. GATTIE PROVIDE ANY SUPPORT WHATSOEVER FOR HIS CONCLUSIONS?

A87. No, he did not. There was nothing in his testimony that justified his statement that further investments were not needed or, that if provided, they would result in "nothing more than additional windfall payments to solar installers." These claims are made with no support, no market analysis, no cost trend analysis, and no investigation of solar installer business models. It is pure speculation and should given no weight by the Commission.

[108] Gattie Supplemental at 23.

Q88. WAS THERE SOME CONFUSION IN THE PRIOR HEARING ABOUT NEW PROVISIONS IN THE IRA?

A88. Yes, the appeared to be some confusion about the eligibility of the new credits for different groups of customers. We offer some clarification below:

- **Residential customers are not eligible for the Production Tax Credit ("PTC").** The PTC, which offers a $0.015/kWh inflation-adjusted credit (currently set to $0.026/kWh) for renewable energy production, was expanded to make solar an eligible technology, but it is only applicable to commercial taxpayers under Section 48. Residential customers do not qualify. SEIA anticipates that while some utility-scale solar developers may opt for the PTC in certain parts of the country, for higher-cost BTM systems, the investment tax credit ("ITC") will remain substantially more lucrative.
- **The residential ITC is not refundable.** Residential customers do qualify for a 30% ITC under Section 25D, but they must have taxable income to offset as the tax credit is not refundable. Non-profit entities are now eligible for direct pay, so this provision might assist non-residential entities such as churches seeking to install BTM solar.
- **The residential ITC was restored to 30%, but it never went below 26% before.** Prior to the passage of the IRA, the Section 25D residential ITC was scheduled to step down from 30% in 2021, to 26% in 2022, to 22% in 2023, and to 0% in 2024 and beyond. However, with the passage of the IRA in 2022, the credit never dropped below 26%. Restoring this credit to 30% is certainly beneficial but it will not have a major impact on the short-term market conditions.
- **Domestic Content and Energy Community Bonus Credits are only for commercial customers.** As with the PTC, the bonus adders for domestic content and energy community locations are only applicable to commercial entities under Section 48. Residential owners will not qualify for these bonus credits.
- **Commercial projects over 1 MW face new conditions on the full ITC.** Unlike before, when all projects received a 30% ITC, commercial projects that exceed 1 MW will now have to comply with prevailing wage and apprenticeship program requirements in order to receive the full 30% ITC. If they meet none of the new requirements, the projects will only receive a 6% ITC.

Q89. DO YOU FEEL THAT THE IRA WILL BE HELPFUL FOR THE BTM SOLAR AND SOLAR PLUS STORAGE MARKET?

A89. Yes. Restoring the ITC from 26% to 30% is helpful, as is securing it for ten years. Many of the IRA provisions are applicable only to commercial projects, such as the bonus tax credits for domestic content and energy community projects. SEIA fully supports these qualifications and anticipates that the new adders will help develop and support a robust domestic manufacturing industry and increase access to solar to more low- and moderate-income customers through programs such as community solar.

Unfortunately, at the same time, other factors impacting the market have driven prices up by well more than the 4% of reestablished ITC. Tariffs continue to be placed on solar cells and modules, and COVID-induced supply chain pinches have impacted the solar market as with many other industries. Likewise, solar projects are not immune to inflation, which has pushed up commodity prices such as steel and aluminum as well as wages. At the same time, the sharp rise in interest rates has made consumer loans and other financing more expensive, further reducing demand. Together, these trends have contributed to push national average prices up from $3.90/w to $4.10/w in the first half of 2022.[109] This price jump effectively negates the benefit of the higher ITC. Along with higher inflation, interest rates have also increased. Many customers finance their solar systems with loans, and the jump in personal loan rates is another near-term headwind.

SEIA certainly anticipates that the market dynamics will improve, and that the IRA will unleash domestic manufacturing and support the creation of well-paying jobs in the industry. But these benefits will take some time to implement and internalize. In the meantime, support from state policies such as net metering will be critical to help the industry through as a new equilibrium is reached.

[109] Tracking the Sun 2022 Edition, Lawrence Berkeley National Laboratory. Available at https://emp.lbl.gov/sites/default/files/2_tracking_the_sun_2022_report.pdfhttps://emp.lbl.gov/sites/default/files/2_tracking_the_sun_2022_report.pdf

V. GPC'S POSITION THAT EXPORTED ENERGY PROVIDES NO CAPACITY VALUE IS UNTENABLE

Q90. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A90. We discuss the Company's testimony and discovery responses applicable to whether exported energy from RNR systems has more value than just avoided energy.

Q91. PLEASE SUMMARIZE YOUR FINDINGS.

A91. We find the Company's testimony regarding a lack of capacity value for solar to be uncompelling. The Company core argument is a circular; since all existing capacity assets are sunk costs, and since new RNR systems cannot reduce sunk costs, there is no avoided capacity benefit. That argument fails to acknowledge that the Company's system has increased in magnitude every year over the past decade, with future, avoidable costs repeatedly being converted into embedded, sunk costs.

Q92. WHAT IS YOUR RECOMMENDATION ON THE COMPANY'S ANALYSIS?

A92. We recommend the Commission continue the line of inquiry it began in the Avoided Cost proceeding and develop new analytical methods for valuing the capacity benefit of renewable resources such as solar. Once this value is established, it should be applied to the export credit that RNR customers receive.

GPC's Arguments Regarding Avoided Capacity Costs are Circular

Q93. HOW DOES THE COMPANY SUPPORT IS CLAIM THAT EXPORTED ENERGY FROM RNR CUSTOMERS DOES NOT PROVIDE ANY CAPACITY BENEFIT?

A93. The Company advances a circular argument related to RNR customers. It starts with the premise that its COSS relies on embedded costs, which by definition are based on assets already in rate base. It continues that because these costs are already incurred, they are not avoidable by RNR customers.[110] As such, it ascribes "no avoided cost benefits to the

[110] "Electricity exported from the solar customer-generator onto the grid does not offset the costs associated with the Company's existing infrastructure investments that are required to serve electricity to the customer-generator." STF-8-11. "Such metrics are used for the allocation of existing fixed costs. Since these costs have been incurred and are not avoided, allocation changes would not be appropriate to determine avoided costs." STF-TAI-8-15

Company's customers for demand- or customer-related services associated with RNR resources' delivery of energy to the grid."[111] In other words, because exported energy from RNR customers does not change the assets already placed into service, there can never be any avoided capacity cost associated with exported energy and paying RNR customers for this service is inappropriate.

Q94. WHAT IS THE LOGICAL FLAW IN THIS ARGUMENT?

A94. It is the Company's overly narrow view that only historic costs should be considered. It is correct that GPC does not pull up poles and wires or retire operating power plants when a RNR customer installs a new BTM solar installation. Based on this interpretation, no action that any customer takes – whether installing BTM solar, energy storage, energy efficiency, demand response, or any other load-modifying technologies – would ever be able to change the embedded cost of service, and thus avoiding capacity costs is impossible.

But it is clearly true that the presence of that PV system, battery, or efficient heat pump on the Company's grid will impact what assets it will need to serve load in the future. As such, incremental RNR capacity reduces demand that will need to be met by the Company's assets, which in turn has an avoided capacity cost benefit.

Q95. HAS GPC'S SYSTEM GROWN OVER THE PAST DECADE?

A95. Yes, it has grown substantially. Figure 8 below shows the net plant in service ("PIS") for the Company by function. The net PIS has climbed from $15.8 billion in 2011 to $26.9 billion in 2021, a compound average growth rate of 5.5% per year.[112] Every rate base component increased in value in every year except for one (production between 2019 and 2020), with the rate base growing by an average of $1.1 billion per year.

[111] STF-TAI-8-13b.
[112] Data from the Company's annual ASR reports.

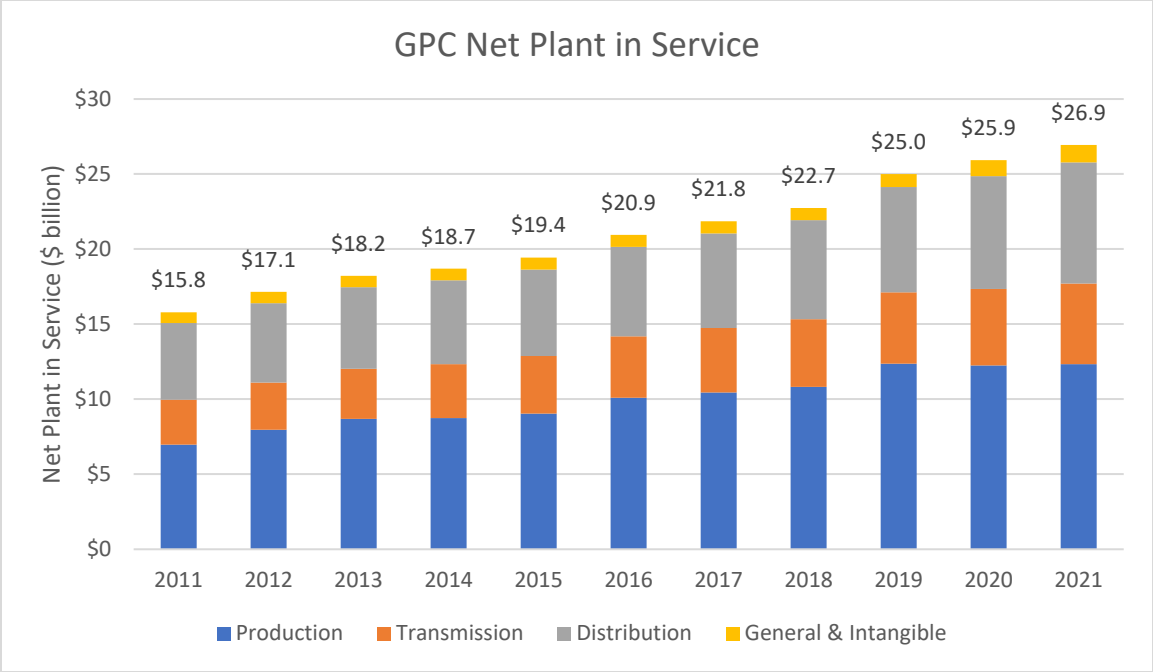


Figure 8 - GPC Net Plant in Service

Despite this, the Company argues that each rate case should only consider the then-existing assets when determining whether BTM solar has capacity value. Unfortunately for GPC's customers, the "then-existing assets" increase every year. The Commission has responsibility to ensure that rates are reasonable and just; this obligation is not limited to current rates, but extends to future rates as well. As it is painfully obvious to all in this proceeding, and has happened every year in the past decade, future costs eventually become current costs which drives up customer's bills. The Commission must see through the Company's circular arguments and recognize and properly compensate capacity benefits associated with exported RNR energy.

Despite Evidence to the Contrary, GPC Maintains Exported RNR Energy Has No Capacity Value

Q96. DOES THE COMPANY AGREE WITH YOUR PREMISE THAT EXPORTED RNR ENERGY HAS CAPACITY VALUE?

A96. No, it does not. The Company makes several arguments against this claim:

- The approved PURPA Avoided Cost methodology in assigns no value to capacity.[113]
- Exported energy is not considered in the Company's long-term generation or transmission planning process.[114]
- The Company completely discounts distributed generation when planning its distribution system.[115]

Q97. WHAT IS YOUR RESPONSE TO THE FIRST POINT ABOUT PURPA AVOIDED COSTS?

A97. It is correct that the Commission removed capacity value from the PURPA avoided costs in its most recent order on this issue.[116] However, at the same time it required the Company to "conduct an analysis of the capacity value of different renewable technologies using the effective load carrying capability method and include the results of this analysis in its 2022 IRP" and directed GPC to meet with Staff to "discuss how location value of renewable resources might be accounted for in the Company's payments to QFs."[117]

The only reason for the Commission to order a study on renewable capacity values and on locational benefits (which are typically associated with the distribution system) is if it wanted to have a more robust basis for determining capacity value for intermittent renewables. Thus, the removal of the old capacity value methodology in the RBC framework is not indicative that the capacity value is and will henceforth be zero. In fact, it is more likely that an updated capacity value will be determined based on new methodologies.

Q98. WHAT IS YOUR RESPONSE TO THE SECOND POINT ABOUT EXPORTED ENERGY NOT BEING CONSIDERED IN THE COMPANY'S LONG-TERM PLANNING FRAMEWORKS?

A98. A89. We do not dispute that the Company does not currently include exported energy in its long-term generation and transmission planning frameworks. However, this is distinct from whether exported energy *should* be evaluated in these frameworks.

The Company expands on this point in its discovery responses. First, it states that because RNR customers have "no long-term, fixed commitment to the Georgia Power system, it is not appropriate to quantify any such medium or long-term demand-related

[113] STF-TAI-8-13a.
[114] STF-TAI-8-16a-b.
[115] STF-TAI-8-16c.
[116] Docket Nos. 4822, 16573, and 19279 Order, Ordering Paragraph E, March 11, 2021. ("Avoided Cost Order")
[117] Avoided Cost Order Ordering Paragraph G and H

benefits, as they are not relied upon in the Company's long-term planning."[118] It also states "The Company plans to meet future customers' needs for generation capacity without taking into consideration the generation exported from RNR resources. Currently, a small amount of MW is produced and consumed onsite from RNR customers relative to the planning process."[119] Put together, the Company's argument is two-fold: RNR customers have not signed a long-term, fixed commitment contract with the Company for exported power; therefore, it is inappropriate to include in the Company's planning process.

Q99. WHAT IS YOUR IMPRESSION OF THIS ARGUMENT?

A99. It is another example of the Company using its current protocols as a justification of its actions rather than addressing the underlying issue. The Company's choice to exclude exported energy from RNR customers is just that – a choice. It could easily account for exported energy in its planning process, just as it does for self-consumed energy. In fact, the distinction that the Company makes between self-consumed energy and exported energy is completely arbitrary when it comes to the overall operation of the grid.

When viewed from the perspective of the bulk power grid – to which its generation and transmission planning processes are applicable – whether 5 kW of BTM generation is self-consumed at 1 Main Street or exported to 2 Main Street is irrelevant. All that matters is that 5 kW was generated. The timing and nature of that generation is important, but these are not the arguments the Company is making.

There was debate in the IRP about the capacity accreditation of solar in different seasons of the year, but these discussions implicate the capacity value – not existence – of PV based on methodologies such as ELCC. The Company is not arguing that the capacity value of exported energy should be lower because of winter generation; it is arguing there is no capacity value for exported energy because it is not included in the planning process.

[118] STF-TAI-8-13b.
[119] STF-TAI-8-16b.

Q100. IS A LONG-TERM, FIXED COMMITMENT CONTRACT A NECESSARY PREREQUISITE FOR BTM ENERGY TO HAVE CAPACITY VALUE?

A100. No. The Company's argument appears to mirror its approach to only include IPP contracts that have a long-term, fixed commitment in its IRP list of resources available to meet demand. Clearly, the Company is not going to pursue similar QF-style long-term contracts with thousands of residential customers for exported energy, nor should it.[120] At the same time, PV generation from BTM solar will happen with or without a contract, and whether or not it is self-consumed or exported to a neighbor. The Company's decision to exclude this resource from planning is a choice, not an emergent property of BTM solar. It is simply one more choice that GPC makes to devalue BTM solar and ultimately discourage its broader deployment.

Q101. ARE THERE OTHER RESOURCES INCLUDED IN THE COMPANY'S LONG-TERM PLANNING PROCESS THAT DO NOT REQUIRE LONG-TERM, FIXED COMMITMENT CONTRACTS BUT INSTEAD RELY ON STATISTICAL ASSUMPTIONS?

A101. Yes. The Company's load forecasts are based on projections of usage from different sectors. The residential sector forecast includes assumptions about appliance usage and housing stock. GPC, as is typical in the industry, made assumptions about the adoption of efficiency standards such as ENERGY STAR.[121] These factors impact how much energy the Company projects will be used by air conditioners, water heaters, televisions, and other categories. Nowhere in this process does the Company require long-term, fixed commitment contracts to install certain types of air conditioners. Instead, it simply assumes an evolution in the marketplace and incorporates a statistical analysis of air conditioning usage. GPC can and should adopt a similar protocol for exported BTM solar.

[120] This does not preclude the possibility of GPC entering into long-term agreements with DER customers to provide certain services, such as exporting solar + storage systems during peak periods. See e.g., Hawaii's program to enroll BTM solar plus storage to provide ten years of Capacity Load Reduction in exchange for compensation. Decision and Order No. 38681, Docket No. 2019-0323, Public Utilities Commission of the State of Hawaii.
[121] GPC 2022 Load and Energy Forecast, Section 1-13, Docket 44160.

Q102. WHAT IS YOUR RESPONSE TO THE THIRD POINT ABOUT THE COMPANY COMPLETELY DISCOUNTING DISTRIBUTED GENERATION ON THE DISTRIBUTION SYSTEM?

A102. The Company's position is unfortunately neither surprising nor inconsistent with its approach to infrastructure planning, but it requires considerable clarification and correction. The Company's full response follows:

> Based on current IEEE standards, there is no offset to any future distribution costs. Consistent with IEEE-1547, the IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems, Southern Company requires all distributed resources (including solar generation facilities) to cease energizing the distribution system upon occurrence of a fault on the distribution system. These resources are required to stay off-line for up to five minutes after the distribution system voltage and frequency are restored to ranges specified in ANSI standard C84.1. Therefore, the distribution system must be capable of serving 100 percent of the customer's load during this timeframe. Further, the distribution system must be capable of serving 100 percent of the load when behind-the-meter generation resources are unavailable for any reason. As a result, planning of the distribution system must assume that the feeders containing such generation are still required to carry the full load connected to these circuits, thereby negating any potential deferment of distribution investment, as referenced in the Renewable Cost Benefits Framework filed in the Company's 2016 and 2019 IRPs in Docket Nos. 40161 and 42310, respectively.[122]

First, the Company conflates the IEEE-1547 standards and distribution system planning. In fact, IEEE-1547 clearly states "This standard does not address planning, designing, operating, or maintaining the Area [electric power system] with DER."[123] Based on this alone, the Company's claim that IEEE standards preclude the offset of any future distribution cost is simply inaccurate.

Additionally, it is unclear whether the Companies are referring to the IEEE 1547-2003 standard, or the updated IEEE 1547-2018 standard which was designed with the expectation that DERs installed under this standard will "play and larger role and, overall, improve power quality" in distribution and transmission networks broadly depending on penetration level.[124]

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[122] STF-TAI-8-16d.
[123] IEEE Std 1547-2018 Section 1.4.
[124] *Impact of IEEE 1547 Standard on Smart Inverters and the Applications in Power Systems*, IEEE, August 2020 at 11. Available at https://www.nrel.gov/grid/ieee-standard-1547/assets/pdfs/smart-inverters-applications-in-power-systems.pdf

GPC also states that resources are "required to stay off-line for up to five minutes" after a trip. In fact, the "delay entering service" parameter is adjustable between 0 seconds and 10 minutes, with a default of 5 minutes.[125] In other words, the Company has the ability to select how long a DER must remain offline after voltage and frequency has returned to normal levels and could set this value as low as 0 seconds. This fact renders moot the Company's next argument that "the distribution system must be capable of serving 100 percent of the customer's load during this timeframe" since the Company has the ability to set this timeframe to 0 seconds.

Q103. WHAT IS YOUR RESPONSE TO THE CLAIM THAT A DISTRIBUTION SYSTEM MUST BE ABLE TO SERVE 100 PERCENT OF THE LOAD OF THE CUSTOMERS?

A103. This statement is contradicted by well-established distribution planning procedures. The Company, like all other utilities, does not plan its distribution system to handle the maximum potential demand of all customers on its system. Instead, it plans its system to serve the *maximum diversified demand* of all customers on its system. This distinction captures the fact that customers do not place their maximum loads on the system simultaneously. One customer may reach her peaks in the morning before leaving for work, while another might reach her peak when charging an EV overnight.

The load diversification factor quickly scales as a function of customers, as seen below in Figure 9.[126] For equipment close to customers such as line transformers, the diversified demand may be 60% lower than the sum of the maximum individual customer demands with as few as 15 customers.

[125] IEEE Std 1547-2018 Section 4.10.3.

[126] Redacted Direct Testimony of William Perea Marcus on Behalf of the Office of Public Utility Counsel at 23, *Application for El Paso Electric Company to Change Rates*, SOAH Docket No. 473-17-2686; PUC Docket No. 46831.

Figure 1: Load Diversity When Sizing Residential Transformers[29]

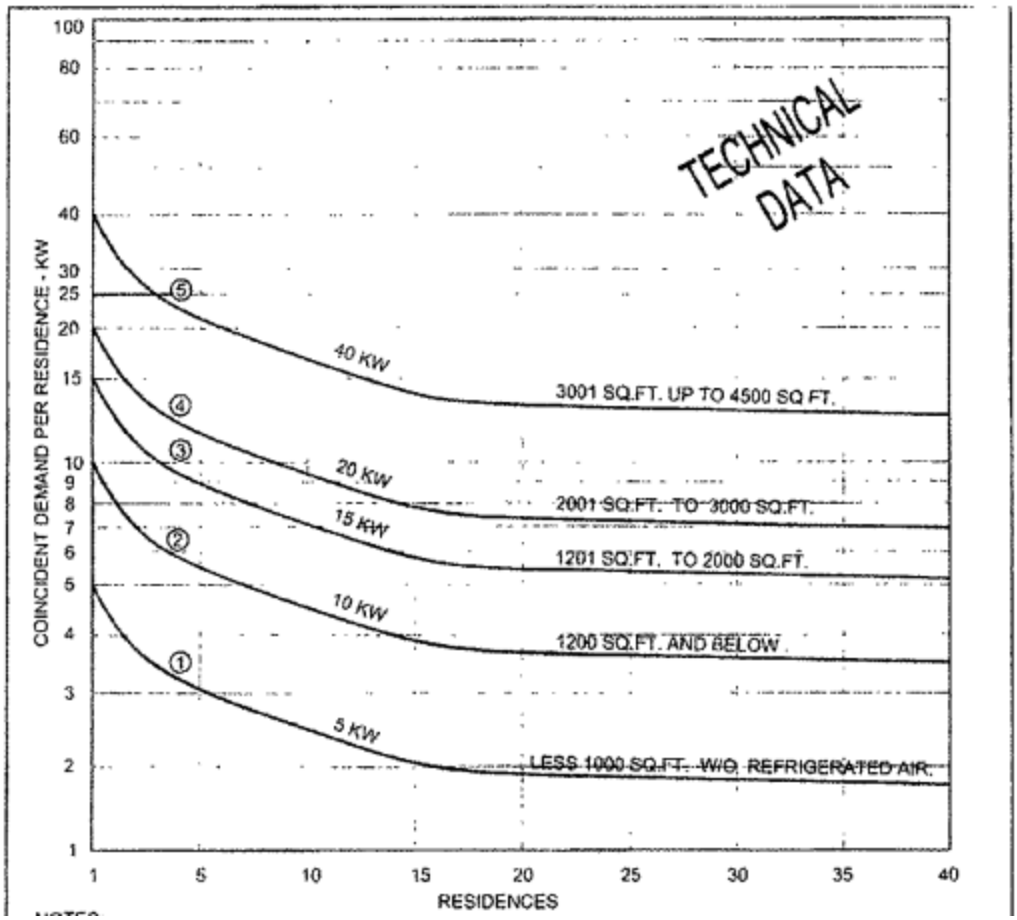


Figure 9 - Residential Load Diversity and Transformer Sizing

For larger assets shared by hundreds of thousands of customers such as feeders or substations, the planned loads experience even higher load diversity. GPC's claim that it must discount all BTM solar generation in distribution planning conveniently ignores that fact that it already builds the system to meet substantially less than 100 percent of potential load of connected customers.

Further, distribution deferrals through DERs such as BTM solar and storage have been demonstrated in other utilities. In practice, the state of Hawaii's Scheduled Dispatch Program ("SDP") and its recently ordered Bring Your Own Device ("BYOD") tariff utilize both advanced inverter functionalities and BTM storage dispatch schedules that produce various benefits to all customers on the electric grid, whether they have installed DERs or

not. These functions produce a variety of benefits such as fast frequency response ("FFR"), capacity load reduction, load shifting at peak, and scheduled dispatch capabilities. All of these functions are provided to the grid by the consumer at distinct time periods and are compensated based on values derived using RESOLVE, a resource investment modeling software utilized by many large investor-owned utilities. Notably, IEEE 1547-2018-compliant smart inverters and modeling software used in Hawaii for this purpose can or already have been installed in Georgia today.

Also notable among these non-wires alternatives is the Brooklyn Queens Demand Management ("BWDM") project at ConEdison in New York. Facing the need for a new $1.2 billion substation, ConEdison worked with customers and businesses to instead develop a suite of demand response, energy efficiency, and DER projects that could defer the need for the new substation. While the project had its challenges, it has also met its peak reduction goal and ConEdison is planning for even more customer-sited load reductions.[127]

Q104. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A104. The Company's arguments that exported energy provides no capacity benefit is unsupported. GPC spends billions of dollars each year on new grid assets, some portion of which can be avoided by reducing demand placed on the system. We recommend the Commission continue its progress towards an analytical framework that establishes this capacity benefit across the various functions of the grid (e.g., production, transmission, and distribution) and incorporates this value into the exported energy credit.

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VI. GASEIA'S COST-BASED ANALYSIS SHOWS RNR CUSTOMERS ARE LESS COSTLY TO SERVE

Q105. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A105. We produce a cost-based analysis of RNR customers that is responsive to the Commission request. First, we discuss several ways a cost-based analysis could be performed. Then, we present two cost-based analyses – one using limited GPC data and one from Michigan – and an outflow energy analysis that we hope informs the Commission on the actual cost reductions created by BTM solar.

Q106. PLEASE SUMMARIZE YOUR FINDINGS.

A106. While we were not able to produce all of the analyses that we had hoped because of the Company's failure to provide timely and usable responses to Staff's discovery, we were able to produce some high-level metrics that supports our conclusion that the cost to serve RNR customers is lower than non-RNR customers. We also walk through a more detailed analysis from Michigan that compares the cost metrics before and after solar was installed to demonstrate the magnitude of cost reduction. We also show that exported energy from RNR customers consistently contributes to load reductions during peak COSS hours and on-peak TOU hours. In each of these cases, it is clear that the burden that RNR customers place on the system during peak hours that drive system costs fall after installing solar and are lower than a typical residential customer.

Q107. WHAT IS YOUR RECOMMENDATION ON THE COMPANY'S INTERCONNECTION FEE PROPOSAL?

A107. As a result of our demonstration that there is a commensurate reduction in cost of service for RNR customers along with the reduction in revenue, there is no cost shift associated with RNR Monthly Netting. GPC had months to demonstrate in its own cost-based analysis that the RNR Monthly Netting pilot should not be extended; it has not only repeatedly failed to do so, it has actively stood in the way of parties such as GASEIA Intervenors that have tried to provide their own analysis using GPC customer data. We respectfully recommend the Commission accept our cost-based analysis despite the limited sources of data that the

Company provided and extend the RNR Monthly Netting program uncapped with a $20 minimum bill.

While Georgia Power Did Not Produce a Cost-of-Service Analysis of RNR Customers, Such an Analysis Is Possible

Q108. HOW COULD ONE DEMONSTRATE THE DIFFERENCE IN COST OF SERVICE FOR RNR CUSTOMERS AS COMPARED TO NON-RNR CUSTOMERS?

A108. One could do this in a few ways, in increasing level of complexity and sophistication. The most straightforward and simplest would be to analyze the usage characteristics of RNR and non-RNR customers that drive costs on the system. For instance, one could compare total usage, TOU period usage, demand during system coincident peak hours, and demand during class peak hours for these customer groups. Given these values drive cost allocation in the COSS, if one were to demonstrate that RNR customers have meaningfully lower loads during high-use times, it would follow that RNR customers would have a lower cost of service.

While the above analysis is simple and straightforward, it does not account for the fact that customers who install solar might look different than the average residential class. An analysis that would account for this would investigate the usage of RNR customers before and after they installed solar. Since of the main concerns expressed in this case is whether the reduction in revenue associated with the installation of BTM solar is offset by the reduction in costs caused on the system, comparing RNR customers before and after solar could help illuminate this issue. If the reduction in key metrics such as demand during COSS hours and on-peak energy usage fall more than revenue collection falls, then one can reasonably conclude there is not a cost shift.

A final, more complex way to do this analysis would be to create a new customer class within the COSS model that represents RNR customers, which, despite the Company's claims to the contrary, is sufficiently precise to manage such a calculation. This would require all corresponding analyses that feed into the COSS to be updated as well. While this

approach would produce an analytical result that could compare the cost to serve RNR customers as a discrete customer group, we do not recommend its use for anything other than this limited analytical scope. To be explicit, we do not recommend that RNR customers be a separate COSS class in the way that different rate groups are COSS classes, nor that RNR customers be prevented from taking service under any currently-available tariff. Rather, an alternative COSS model could be developed simply to analyze how cost of service for RNR customers compares to non-RNR customer to help inform the conversation around the continuance of the Monthly Netting pilot.

Q109. DID GPC PRESENT ANY OF THESE ANALYSES IN ITS TESTIMONY?

A109. No, it did not.

Q110. WERE YOU ABLE TO PERFORM ANY OF THESE ANALYSES?

A110. We were able to complete the first analysis (RNR customers vs. non-RNR customers) using the partial data set provided from the Company. We were not able to produce the second analysis (RNR customers before and after solar) because the Company did not provide data that Staff requested in a timeline manner. Had that data been available and usable, it may have been possible to perform the second analysis. We were not able to do the more complex analysis (COSS model) for the reasons discussed previously.

Cost-Based Analysis #1 – RNR vs. Non-RNR Customers

Q111. PLEASE DISCUSS YOUR FIRST ANALYSIS COMPARING USAGE OF RNR CUSTOMERS AND NON-RNR CUSTOMERS.

A111. This analysis used hourly load data by tariff[128] and hourly inflow (power consumed from GPC's grid) and outflow (power exported to GPC's grid) data provided for 1,016 RNR customers in 2021.[129] The non-RNR customer data set was developed from hourly load data by tariff provided by the Company that was first converted to a per capital usage by dividing

[128] STF-TAI-1-12 Attachment
[129] STF-TAI-8-9 Attachment A.

total tariff usage by the count of customers.[130] Inflow and outflow data for the RNR customers was averaged for each hour of the year. Once these initial steps were done, data could be compared between the two sets. As we discussed in the first phase of the hearing, since 2021, the TOU-RD tariff has been greatly expanded with defaulted-in customers that have lower-than-average usage.

Q112. HOW IS THE INFORMATION PRESENTED, AND HOW ARE THE COSS METRICS BEST INTERPRETED?

A112. In each of the following graphs, RNR customers' data is presented in two ways. The first is the "RNR Inflow" which represents the amount of energy consumed by these customers from the grid. The second is "RNR Net", which nets outflow energy with inflow on a customer-by-customer, hour-by-hour basis to produce a "net" inflow from the Company.[131]

The COSS demand metrics of 4CP, 12CP, and Class NCP are also used below. In the Company's COSS model, the 4CP, 12CP, and Class NCP metrics most directly correlate to transmission, production, and distribution system cost causation, respectively. That said, we and other parties have argued that in a summer peaking utility such as GPC, the 4CP allocator is more appropriate for production costs.

All of the values below are based on customer meter reads. This means that they are not grossed up for line losses. Given that marginal line losses can be substantially higher than average line losses, and that line losses during hot summer days are higher than mild spring days, the COSS demand figures below actually understand the magnitude of system-wide demand reductions.

Q113. HOW DO THE RNR CUSTOMERS AND NON-RNR CUSTOMERS COMPARE IN TERMS OF BASIC USAGE?

[130] STF-TAI-2-1 provided customer counts by month by tariff. These were scaled linearly to produce intra-month customer counts.

[131] For example, if a customer had inflows of 2.5 kWh and outflows of 0.5 kWh in the same hour, the RNR Inflow would be 2.5 kWh while the RNR Net would be 2.0 kWh.

A113. After installing solar, RNR customers appear to be slightly larger than average users of energy. Figure 10 shows how the monthly usage profile tracks other residential tariffs other than TOU-PEV, which consistently has the highest usage of all residential tariffs.

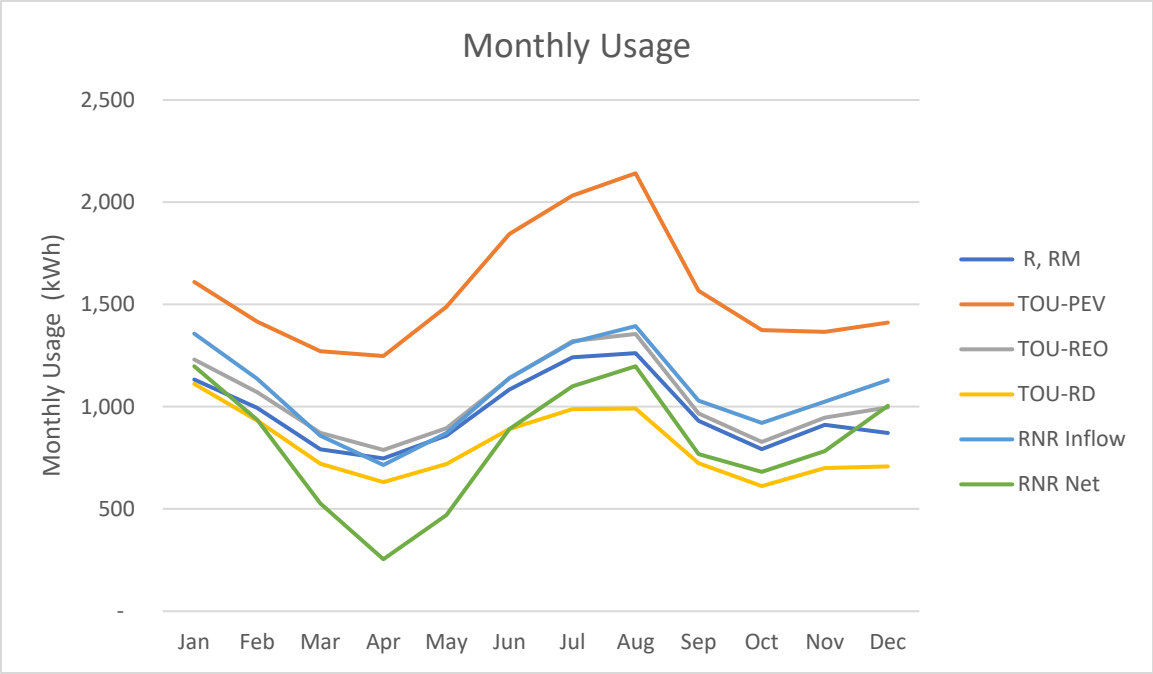


Figure 10 - Monthly Usage by Tariff

When one analyzes hourly usage, the clear pattern of solar generation emerges. In Figure 11 showing summer months, RNR Inflow customers use more energy during the morning and overnight periods than the other residential tariffs, and less energy during midday. When outflows are considered, the RNR Net values fall substantially during midday. RNR Inflow values largely remain below the other tariffs for most of the TOU peak hours.

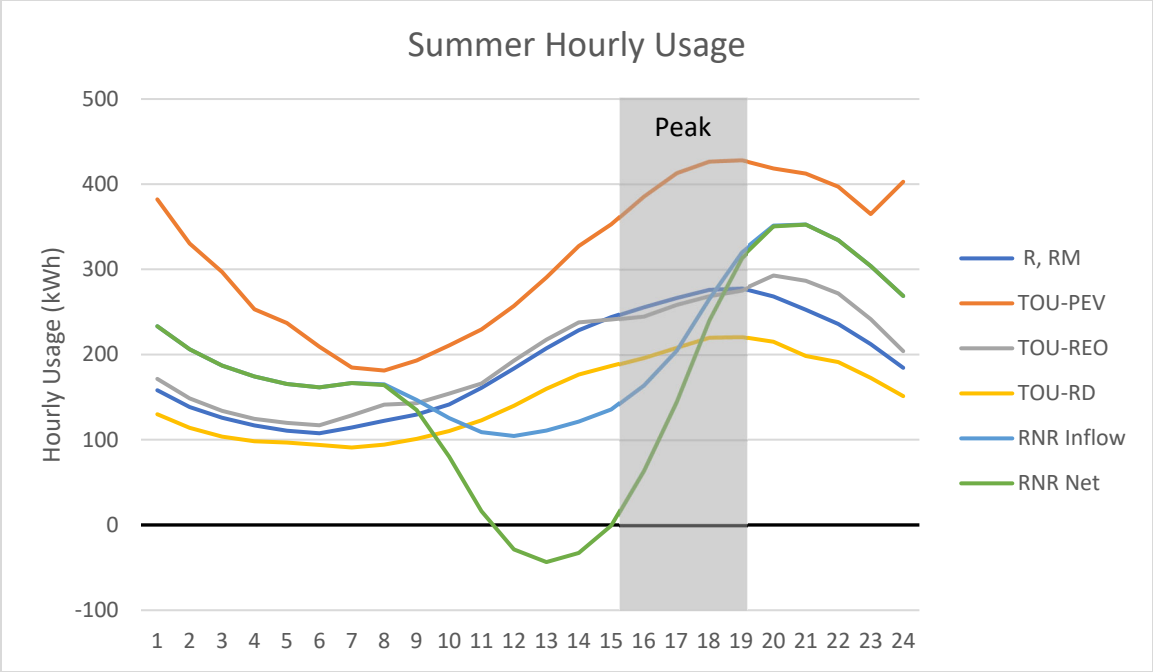


Figure 11 - Summer Hourly Usage by Tariff

Figure 12 below shows the hourly usage in non-summer months. Once again, the RNR Inflow customer use more energy than other tariffs except TOU-PEV in the evening, overnight, and morning hours, and less during midday. RNR Net customers realize more outflow during non-summer months, pushing midday net usage negative.

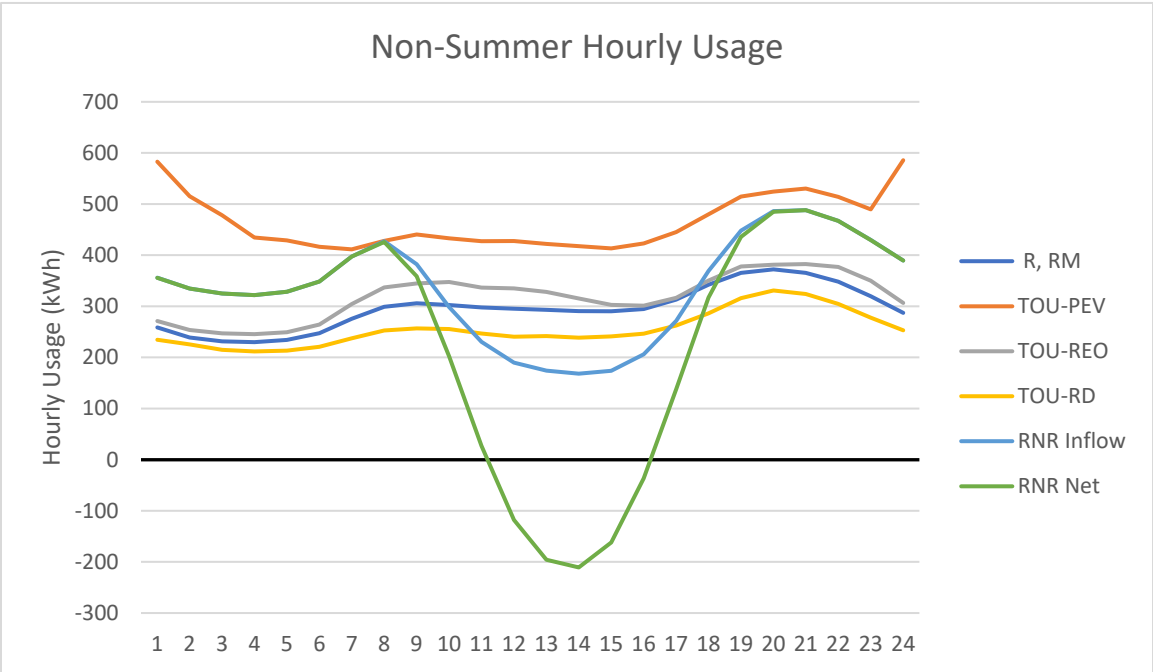


Figure 12 - Non-Summer Hourly Usage

Q114. HOW DID LOAD DURING KEY COSS HOURS VARY BETWEEN THE TWO CUSTOMER SETS?

A114. BTM solar meaningfully reduced the RNR customer's load during the 4CP hours and all but a few winter 12CP hours, as seen in Figure 13 below. Where the preceding charts showed that total consumption was slightly higher for RNR Inflow customers, the demand during key COSS hours is comfortably lower than the other tariffs in all but the core winter months. And as storage attachment rates increase, even those winter morning peaks could be reduced.

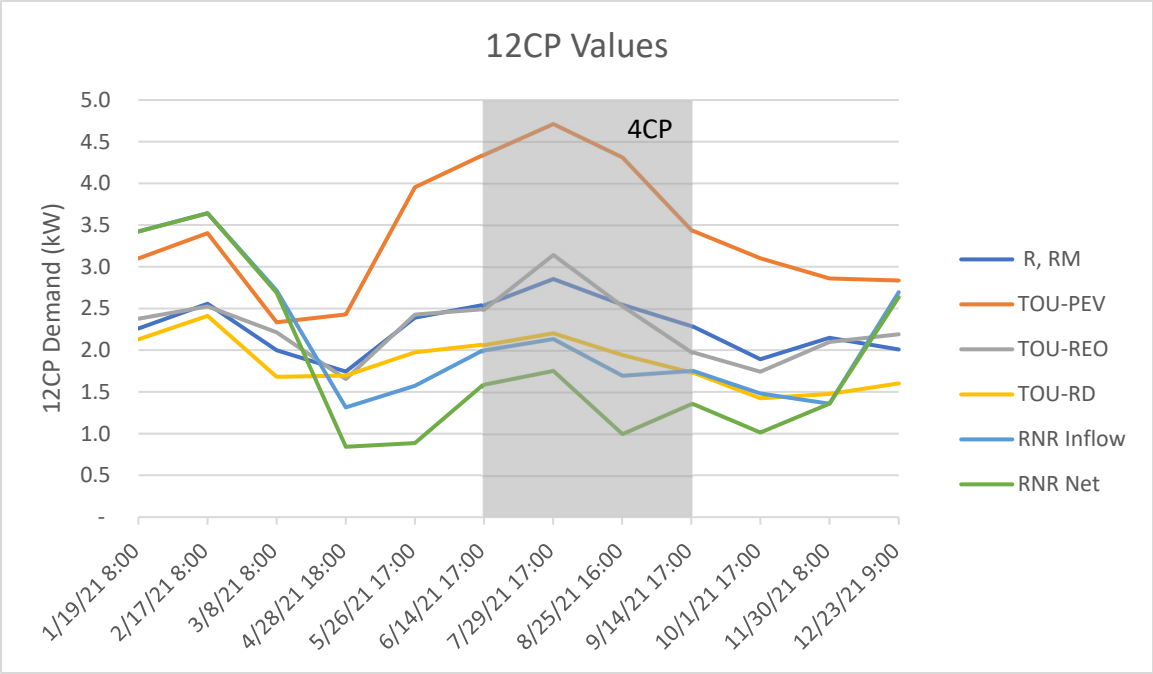


Figure 13 - 12CP Demand

Figure 14 shows the average loads on the 4CP, 12CP, and Class NCP hours. RNR Inflow customers' 4CP is comfortably below the R, TOU-PEV, and TOU-REO, and is even lower than the small customer TOU-RD group. RNR Inflow 12CP is slightly lower than the other tariffs, but falls more when outflow is included. Class NCP occurred on July 29, 2021 between 6 and 7 PM, and while usage for the RNR Inflow group did not peak during this hour, it was higher than other tariff groups.

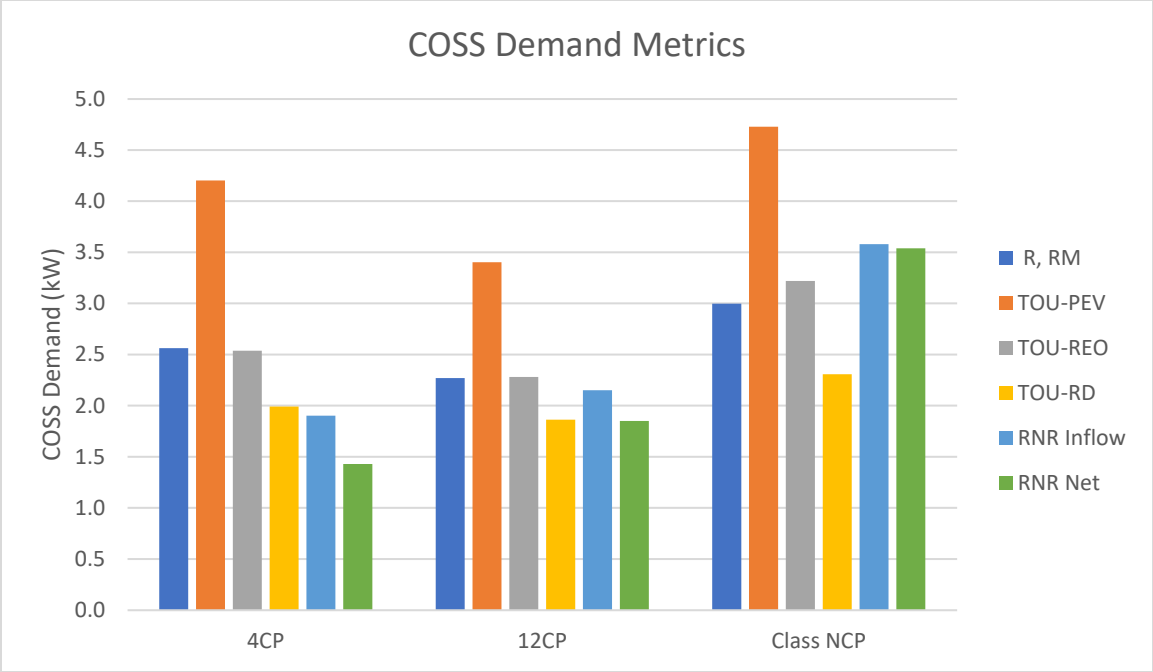


Figure 14 - COSS Demand Metrics

Q115. HOW DID ENERGY CONSUMPTION FALL WITHIN THE TOU PERIODS ACROSS THE TARIFFS?

A115. While analyzing COSS demand metrics is an important consideration for COSS, it is somewhat limited in this analysis given we only had complete data for a single year. If one of the key 12CP, 4CP, or Class NCP hours was partly cloudy in 2021, it could impact the above metrics in a way that may not reflect the long-term averages during peak hours. As such, investigating how energy consumption falls across the TOU periods provides a bit more latitude in the event only a single year of data is available.

Subtle but clear trends exist in the TOU energy use of these customers. As could be anticipated from Figure 11 above, RNR Inflow customers use less energy during peak TOU hours than other customers and more energy during the super-off-peak ("SOP") period. When outflow is factored in, RNR Net customers' peak usage falls even further. Figure 15 and Figure 16 show these relationships both in absolute and normalized terms.

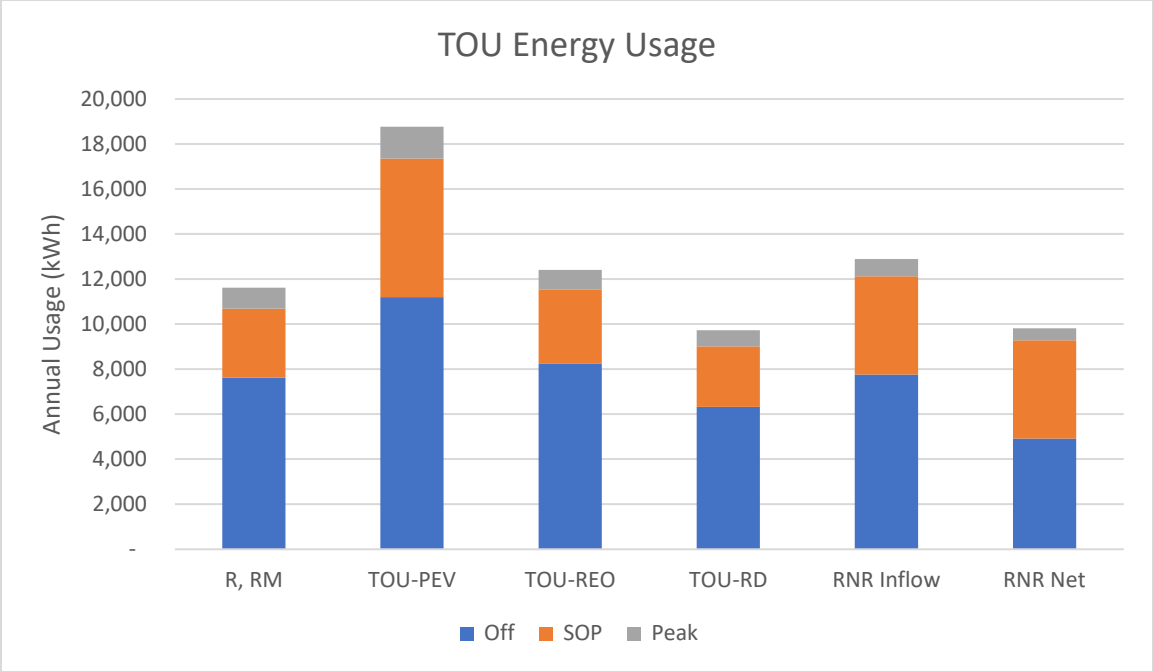


Figure 15 - TOU Energy Use by Period

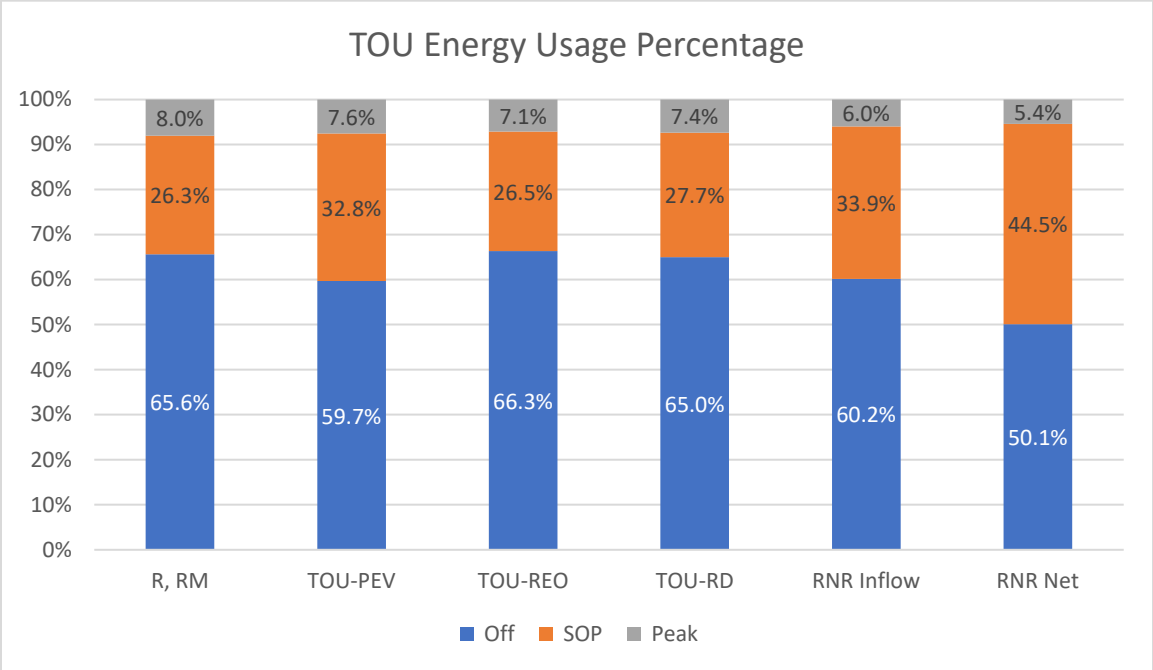


Figure 16 - TOU Energy Usage Percentage by Period

When compared to the R class, RNR Inflow customers use meaningfully less energy on peak (772 kWh vs. 935 kWh) even though their overall usage is higher. Off-peak usage is nearly identical between the groups (7,754 kWh for RNR Inflow vs. 7,623 kWh for R),

meaning that the increased usage occurs during the low-cost, overnight SOP period. This is readily visible in the percentage graph, showing lower peak usage (6.0% vs. 8.0%) and higher SOP usage (33.9% vs. 26.3%). These are the exact metrics that one would want in a customer; use less energy during high-cost peak hours and more energy during low-cost SOP hours.

Q116. WHAT IS THE FINAL CHART YOU HAVE PREPARED?

A116. The final chart in Figure 17 below shows the load factors using the COSS demand metrics.[132] Load factor relates the demand of a customer or customer group to its energy usage and can be viewed as a measure of the efficiency of system usage. The higher the load factor, the more consistently or "efficiently" a customer used the system.

As expected, the lower 4CP demand values coupled with higher energy consumption causes the 4CP RNR Inflow and RNR Net load factors to climb substantially above all other tariffs. The RNR customers approach a 4CP load factor of 80%, while the remaining tariffs are in the 50-55% range. The increase on the 12CP is not quite as large, but RNR Inflow customers still attain a 68% load factor, roughly 10% higher than the R group. The Class NCP load factor is marginally lower for RNR Inflow customers, reflecting the higher demand metric used in that calculation.

[132] Mathematically, a load factor is the energy usage over a period divided by the product of maximum demand and the number of hours in a period. For these values, this is LF = Total Energy / (COSS Demand * 8760)

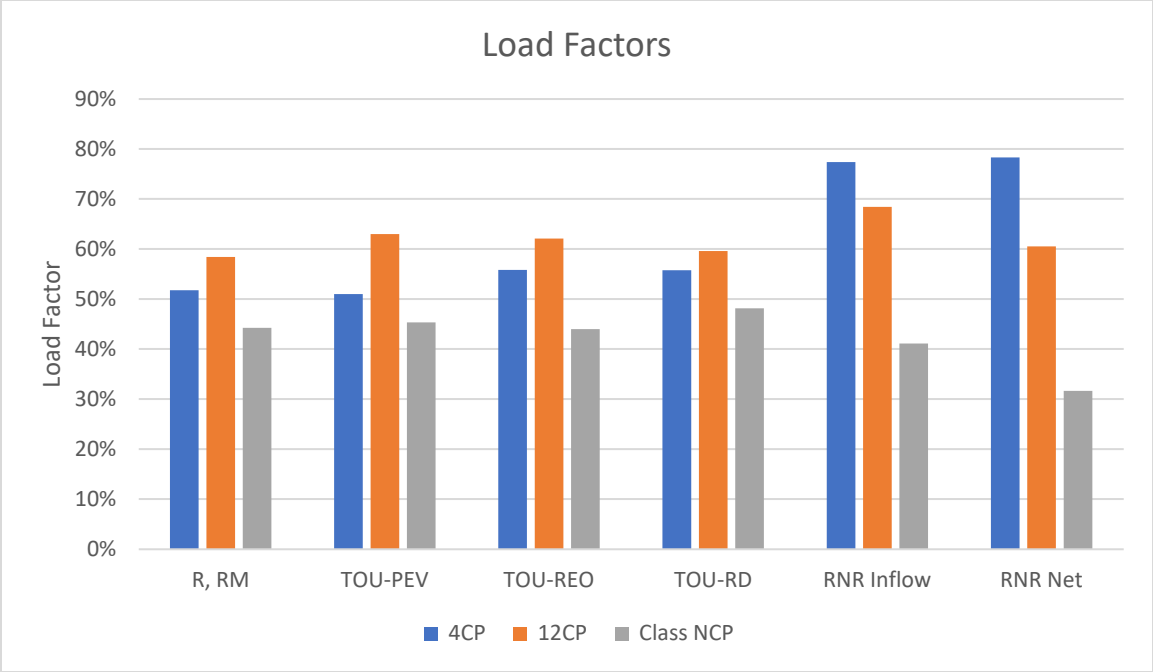


Figure 17 - Load Factors

Q117. WHAT ARE YOUR OVERALL CONCLUSIONS BASED ON THIS FIRST ANALYSIS?

A117. The data above strongly support GASEIA's position that RNR customers have a lower cost of service than do non-RNR customers. RNR Inflow customers have lower 4CP and 12CP demand allocators, use less energy during on-peak periods, and have higher 4CP and 12CP load factors. These are all hallmarks of putting less stress on the system during hours that drive system costs. When outflow energy is considered, the RNR Net data exhibits even greater cost reductions, with further falls in COSS metrics and even lower peak energy usage.

The demand reductions are most strongly concentrated in the 4CP (transmission) and 12CP (production) metrics. But as discussed, GPC's allocation methodology is unusually for a summer-peaking utility, and it is our experience that similar utilities use a 4CP allocator for production and a 12CP allocator for transmission. If this more standard convention was used by the Company, the demand reduction from RNR customers would be better reflected in cost reductions.

Cost-Based Analysis #2 – BTM Customers Before and After Solar Installation

Q118. WERE YOU ABLE TO PERFORM THE SECOND ANALYSIS DISCUSSING CHANGES THAT OCCURRED AFTER CUSTOMERS INSTALLED SOLAR IN ANOTHER CASE?

A118. [Mr. Lucas] Yes, I was. In another DTE rate case, the utility provided 2018 and 2020 hourly usage for 342 residential customers who installed BTM PV in 2019. It also provided hourly data for non-PV residential customers over this time period. I was able to use this data to analyze the usage pattern changes for customers before they installed solar and after they installed solar, including the timing and magnitude of both inflows from DTE and outflows to DTE.

Figure 18 below shows the key results from this analysis. Customers that installed BTM solar substantially reduced their usage during critical COSS hours (e.g., 4CP, 12CP, Class NCP). After considering both inflow reduction and outflow during the same hour, BTM DG customers nearly eliminated their 4CP load (-91%), substantially reduced their 12CP load (-62%), and meaningfully reduced their Class NCP (-41%)[133]

[133] Direct Testimony of Kevin Lucas on Behalf of The Ecology Center, The Environmental Law & Policy Center, and Vote Solar, Case No. U-20836, Michigan Public Service Commission at 56. 2020 Post DG is equivalent to RNR Net in the first analysis.

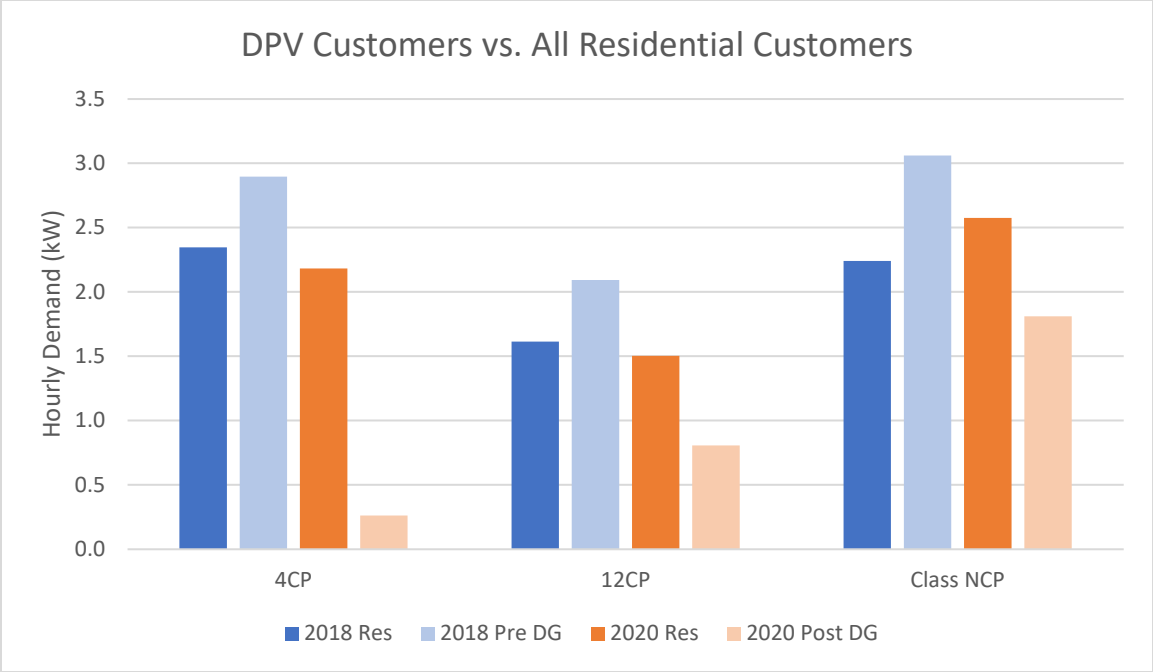


Figure 18 - DTE BTM PV COSS Analysis

Q119. WHILE IT IS CLEAR THE PEAK DEMAND METRICS FELL SUBSTANTIALLY, DID THE ENERGY CONSUMPTION WHICH DRIVES BILLS FALL BY THE SAME AMOUNT?

A119. No, it did not. DG customer inflows fell from about 912 kWh a month before PV to about 684 kWh a month after DG, a 25% reduction. So, while these customers cut their demand on the system by 91%, 62%, and 41% for these key metrics, they only reduced their inflow energy purchased from DTE at full retail rates by 25%. Further, these DG customers – like GPC's RNR customers – still used more inflow energy even after installing PV (684 kWh/month) than the typical residential customer (632 kWh/month) while simultaneously using less inflow energy during on-peak hours.

Q120. WHAT IS YOUR TAKEAWAY FROM THIS ANALYSIS?

A120. The key metrics that drive cost of service – 4CP, 12CP, Class NCP, total energy, on-peak energy – all improved after installing solar. But they did not fall equivalently. Usage during the critical 4CP and 12CP hours and on-peak TOU periods fell substantially more than did overall energy. Thus, while the revenue that these customers paid through their inflow fell,

load during cost-causing hours fell substantially more. The result is that there is no cost shift as the cost to serve these customers fell more than the revenue reduction.

Q121. IS THERE A REASON TO THINK THAT GPC'S RNR CUSTOMERS WOULD PERFORM SIMILARLY IF YOU WERE ABLE TO ANALYZE THEM?

A121. Yes. While GPC's and DTE's systems are different, some usage patterns such as high demand in the summer, medium demand in the winter, and low demand during shoulder months is common across both territories. Georgia customers use more energy overall than DTE customers, but Georgia also has higher insolation than DTE customers. We would expect directionally similar results had we been able to perform the analysis we had hoped to.

RNR Outflow Meaningfully Contributes to COSS Demand and Peak TOU Energy Reductions

Q122. DID YOU ANALYZE THE GENERATION PROFILE OF RNR OUTFLOW ENERGY?

A122. Yes. Outflow energy is produced when there is solar generation in excess of a customer's instantaneous household load. For instance, if a PV generator is producing 5 kW of power and household load is 4 kW, then 1 kW of power will flow to the system and most likely be consumed by the customer's neighbor.

We aggregated data from the hourly outflows from 2019, 2020, and 2021 and broke the data into summer and non-summer months.[134] Even though outflow is a function of both solar generation and customer load, as seen below in Figure 19, the outflow shape closely mirrors solar production. More than a third of outflow energy in the summer occurs during the 2 PM to 7 PM hours that comprise the TOU peak period. Further, the average outflow during these peak periods is 0.5 kW per residential customer. Multiplied by roughly 4,200 residential customers in the full RNR program and this is a non-trivial 2.1 MW resource.

[134] These values only represent about 1/5th of all RNR customers in the limited data set that GPC provided.

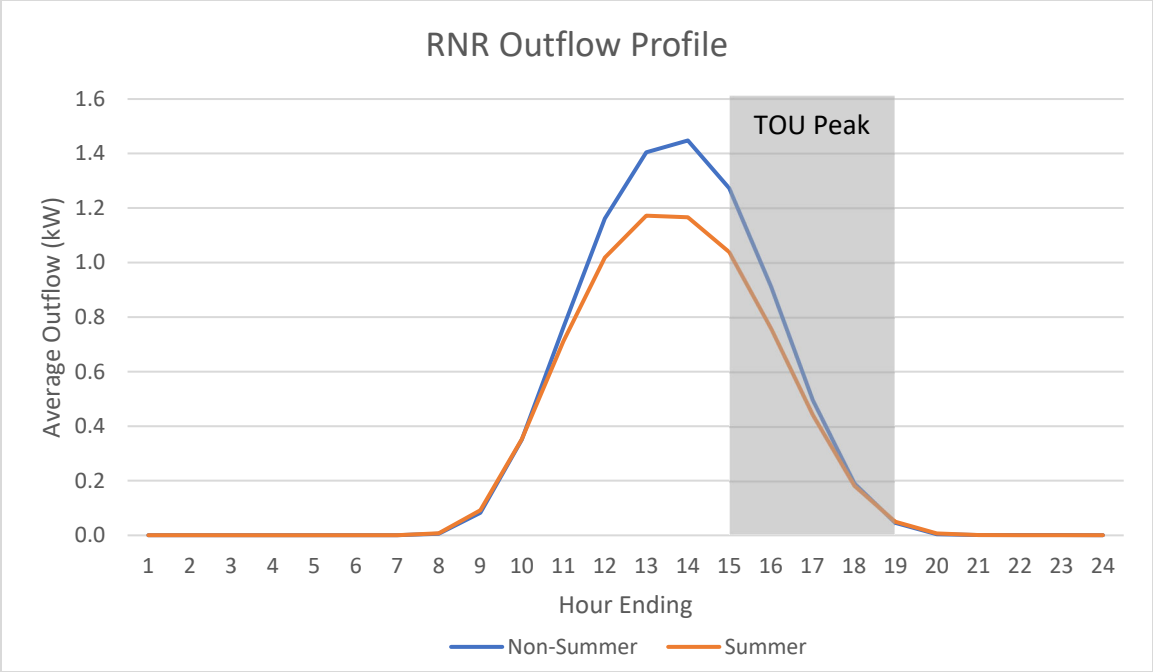


Figure 19 - RNR Outflow Profile

Q123. DID YOU LOOK AT OUTFLOW DURING THE SPECIFIC 12CP HOURS?

A123. Yes. As expected, solar outflow contributed during 12CP hours from April to October and did not contribute substantially during November to March as seen in Figure 20 below. The Company's system is still a summer-peaking system, so these outflows remain valuable to the transmission and production systems. The outflow is also relatively consistent during summer months, reducing concerns that the resource will be broadly unavailable during those hours. If scaled to all residential RNR customers, these outflows would reduce demand during the 4CP hours by about 1.5 MW to 1.8 MW.

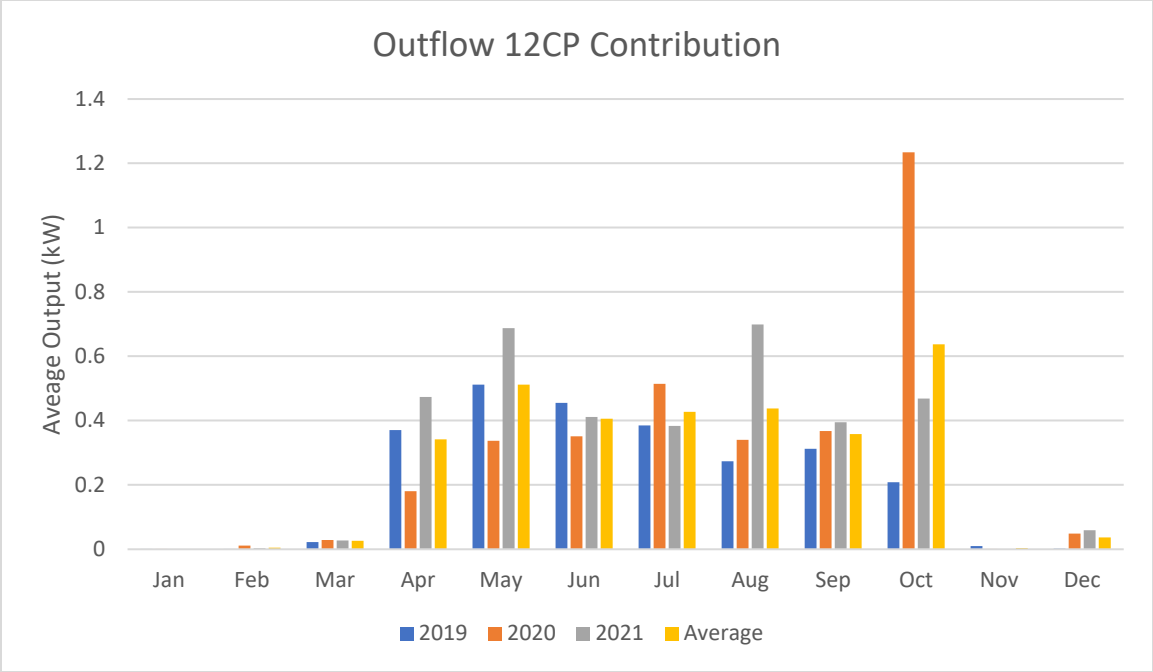


Figure 20 - Outflow 12CP Contribution

Q124. WHAT IS YOUR CONCLUSION REGARDING OUTFLOW FROM RNR CUSTOMERS?

A124. Outflow is a meaningful contributor to reducing peak energy use and contributing to 7 of the 12 CP hours, including all of the 4CP hours. Outflow does vary depending on generation and self-consumption, but when averaged across the entire population of RNR customers, outflow was reasonably consistent. These facts counter GPC's argument that only resources with long-term, fixed commitments can be relied upon to produce demand reductions.

GASEIA's Analyses Supports and Extension of the RNR Monthly Netting Program with a Minimum Bill

Q125. BASED ON YOUR ANALYSES ABOVE, WHAT DO YOU RECOMMEND WITH RESPECT TO THE RNR MONTHLY NETTING PROGRAM?

A125. We reiterate our position that the RNR Monthly Netting program should be extended without limitation with a full retail rate offset. We continue to support the implementation of a $20 per month minimum bill that we introduced in the 2022 IRP as a mechanism to prevent

customers from reducing their bill below a reasonable threshold.[135] This would ensure that RNR customers contributed to the cost of the distribution system each month.

Q126. WHY DO YOU BELIEVE THE RNR MONTHLY NETTING PROGRAM SHOULD EXTENDED WITHOUT A CAP?

A126. Because we have reasonably demonstrated that there is no cost shift from RNR customers to non-RNR customers through monthly netting. The reduction in revenue that results from providing retail-rate credits is offset by a concurrent reduction in cost of service. The only justification for limiting the scope of the RNR Monthly Netting program is out of concerns of a cost shift. But the Company repeatedly failed to produce any evidence of an actual cost shift, going so far as to claim that its COSS model was not precise enough to produce meaningful results.

Into that gaping vacuum, GASEIA Intervenors have introduced our own cost-based analysis. In total, the analyses above show that RNR customers 1) have lower cost of service than non-RNR customers due to the significantly lower loads during hours that contribute to production and transmission costs and 2) reduce their cost of service after installing solar as compared to before installing solar. Further, we have shown that exported outflow energy is reasonably consistent across the years and contributes to further reductions in peak usage by meeting portions of the RNR customer's neighbor's load. So, while the revenue that these customers pay to the Company is reduced after installing solar, there is a concurrent reduction in costs. And, in Company's own words, there is no justification to claim a cost shift if "the amount of lost or avoided revenues also result in a comparable reduction in the Company's retail cost of service/ revenue requirement."[136]

While this analysis was not as complete as we would have liked given the Company's inability to furnish accurate data that was responsive to discovery, it still demonstrates the lower cost of service of RNR customers. We also feel that this analysis is robust enough to

[135] GASEIA Intervenors Direct at 40, Docket Nos. 44160 & 44161.
[136] STF-TAI-8-13.

demonstrate a lack of cost shift and for the Commission to expand the RNR Monthly Netting program. And with this expansion, we expect that Georgia will see increased investment, economic activity, and job creation that comes with a robust BTM solar market.

Q127. DOES THIS CONCLUDE YOUR TESTIMONY?

A127. Yes, it does.

EXHIBIT 1: RESIDENTIAL SOLAR PENETRATION BY STATE
AS OF Q3 2022

Cumulative Residential Solar Capacity		
State	MW	Rank
California	10,035.7	1
Arizona	1,846.3	2
Florida	1,359.5	3
Texas	1,276.6	4
New York	1,267.5	5
New Jersey	1,245.5	6
Massachusetts	989.8	7
Maryland	787.0	8
Nevada	689.5	9
Colorado	639.9	10
Connecticut	535.7	11
Hawaii	534.2	12
Utah	421.9	13
Pennsylvania	383.9	14
Puerto Rico	382.3	15
Illinois	346.3	16
North Carolina	280.9	17
Washington	254.8	18
South Carolina	254.6	19
Virginia	250.9	20
New Mexico	237.9	21
Oregon	215.5	22
Missouri	215.4	23
Louisiana	128.1	24
Michigan	115.9	25
Ohio	101.1	26
New Hampshire	99.1	27
Idaho	96.8	28
Vermont	93.5	29
Washington DC	89.6	30
Rhode Island	88.9	31
Minnesota	84.6	32
Delaware	75.4	33
Arkansas	67.1	34
Indiana	65.7	35
Iowa	63.6	36
Wisconsin	62.7	37
Maine	59.3	38
Georgia	53.6	39
Kansas	33.8	40
Oklahoma	33.5	41
Kentucky	28.8	42
Montana	22.9	43
Tennessee	17.2	44
West Virginia	16.4	45
Nebraska	12.8	46
Alaska	12.2	47
Wyoming	11.9	48
Mississippi	4.1	49
Alabama	1.4	50
South Dakota	0.8	51
North Dakota	0.5	52

Residential Solar Capacity per Capita		
State	W/Person	Rank
Hawaii	370.6	1
California	255.8	2
Arizona	253.7	3
Nevada	219.3	4
Connecticut	148.6	5
Vermont	144.8	6
Massachusetts	141.7	7
New Jersey	134.4	8
Washington DC	133.7	9
Maryland	127.7	10
Utah	126.4	11
Puerto Rico	117.1	12
New Mexico	112.4	13
Colorado	110.1	14
Rhode Island	81.1	15
Delaware	75.1	16
New Hampshire	71.4	17
New York	63.9	18
Florida	62.4	19
Idaho	50.9	20
Oregon	50.7	21
South Carolina	49.0	22
Maine	43.3	23
Texas	43.2	24
Missouri	34.9	25
Washington	32.9	26
Pennsylvania	29.6	27
Virginia	29.0	28
Louisiana	27.7	29
Illinois	27.3	30
North Carolina	26.6	31
Arkansas	22.2	32
Montana	20.8	33
Wyoming	20.5	34
Iowa	19.9	35
Alaska	16.6	36
Minnesota	14.8	37
Michigan	11.5	38
Kansas	11.5	39
Wisconsin	10.6	40
Indiana	9.7	41
West Virginia	9.2	42
Ohio	8.6	43
Oklahoma	8.4	44
Nebraska	6.5	45
Kentucky	6.4	46
Georgia	5.0	47
Tennessee	2.5	48
Mississippi	1.4	49
South Dakota	0.9	50
North Dakota	0.7	51
Alabama	0.3	52

Single-Family Homes with Solar		
State	Percent	Rank
Hawaii	27.0%	1
California	15.4%	2
Nevada	9.4%	3
Arizona	9.0%	4
Washington DC	8.5%	5
Massachusetts	7.3%	6
Connecticut	6.4%	7
Utah	6.4%	8
New Jersey	6.0%	9
Colorado	5.2%	10
New Mexico	5.0%	11
Puerto Rico	4.9%	12
Maryland	4.3%	13
Rhode Island	4.3%	14
New York	3.8%	15
Vermont	3.4%	16
New Hampshire	2.3%	17
Delaware	2.2%	18
Oregon	2.2%	19
Florida	2.0%	20
Idaho	2.0%	21
Texas	2.0%	22
Missouri	1.5%	23
South Carolina	1.4%	24
Washington	1.3%	25
Illinois	1.1%	26
Louisiana	1.1%	27
Virginia	1.1%	28
Pennsylvania	1.0%	29
North Carolina	0.8%	30
Alaska	0.7%	31
Maine	0.7%	32
Wyoming	0.7%	33
Montana	0.6%	34
Arkansas	0.6%	35
Iowa	0.6%	36
Minnesota	0.5%	37
Wisconsin	0.5%	38
Michigan	0.4%	39
Ohio	0.3%	40
Kansas	0.3%	41
Oklahoma	0.3%	42
Indiana	0.3%	43
Georgia	0.2%	44
Kentucky	0.2%	45
Nebraska	0.2%	46
West Virginia	0.2%	47
Tennessee	0.1%	48
Mississippi	0.1%	49
South Dakota	0.0%	50
North Dakota	0.0%	51
Alabama	0.0%	52

Sources: SEIA/Wood Mackenzie U.S. Solar Market Insight Q3 2022, U.S. Census Bureau