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BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

STATE OF GEORGIA

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

Hearing Room 110
Georgia Public Service Commission
244 Washington Street
Atlanta, Georgia
Tuesday, November 29 2022

The above-entitled matter came on for hearing
Pursuant to Notice at 9:30 a.m.

PRESENT WERE:
TRICIA PRIDEMORE, Madam Chair
TIM ECHOLS, Vice-Chairman
FITZ JOHNSON, Commissioner
LAUREN "BUBBA" MCDONALD, Commissioner
JASON SHAW, Commissioner

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1	I N D E X				
2	WITNESSES:	DIRECT	CROSS	REDIRECT	RECROSS
3	AARON P. ABRAMOVITZ				
	SARAH P. ADAMS				
4	ADAM D. HOUSTON				
	MICHAEL B. ROBINSON				
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1 MADAM CHAIR PRIDEMORE: Good morning, Everyone.
2 All right. Let's get started. We are going to call
3 to order Docket No. 44280, Georgia Power Company's
4 2022 Rate Case, rebuttal testimony days are before
5 us. Go through a list of appearances. I just want
6 to remind everybody, we have a packed schedule and
7 two days to do it.
8 There's probably a Smokey and the Bandit
9 reference in this right now, but I haven't come up
10 with it yet. So let's --
11 Have you, Commissioner McDonald?
12 COMMISSIONER MCDONALD: Pardon?
13 MADAM CHAIR PRIDEMORE: Got a Smokey and the
14 Bandit reference for us?
15 MR. GALLOWAY: Long way to go...
16 MADAM CHAIR PRIDEMORE: Long way to go and a
17 short time to get there. There you go.
18 Way to go, Mr. Galloway.
19 Okay. So let's go down the list of
20 appearances.
21 Georgia Public Service Commission.
22 MR. WALSH: Thank you, Madam Chair. On behalf
23 of the Public Interest Advocacy Staff, it's Dan
24 Walsh, Preston Thomas and Griffin Ingraham.
25 MADAM CHAIR PRIDEMORE: Thank you, Mr. Walsh.

1 Georgia Power Company.

2 MR. HEWITSON: Good morning. Steve Hewitson,
3 Brandon Marzo and Allison Prior on behalf of Georgia
4 Power Company.

5 MADAM CHAIR PRIDEMORE: Mr. Hewitson.
6 Americans for Affordable Clean Energy.

7 MR. GALLOWAY: Good morning, Madam Chair.
8 Newton Galloway and Terri Lyndall for AACE.

9 MADAM CHAIR PRIDEMORE: Mr. Galloway.
10 ChargePoint.

11 MR. FYKES: Good morning, Lucas Fykes on behalf
12 of ChargePoint.

13 MADAM CHAIR PRIDEMORE: Mr. Fykes.
14 Commercial Group.

15 MR. JENKINS: Good morning, Alan Jenkins.

16 MADAM CHAIR PRIDEMORE: Thank you, Mr. Jenkins.
17 Concerned Ratepayers for Georgia.

18 (No Response.)

19 MADAM CHAIR PRIDEMORE: Concerned Ratepayers
20 for Georgia.

21 (No Response.)

22 Concerned Ratepayers for Georgia.

23 MADAM CHAIR PRIDEMORE: Not present.
24 Cypress Creek Renewables.

25 (No Response.)

1 MADAM CHAIR PRIDEMORE: Cypress Creek
2 Renewables.
3 (No Response.)
4 MADAM CHAIR PRIDEMORE: Cypress Creek
5 Renewables.
6 (No Response.)
7 MADAM CHAIR PRIDEMORE: Not present.
8 EVgo Services, LLC.
9 (No Response.)
10 MADAM CHAIR PRIDEMORE: EVgo Services, LLC.
11 (No Response.)
12 MADAM CHAIR PRIDEMORE: EVgo Services, LLC.
13 (No Response.)
14 MADAM CHAIR PRIDEMORE: Not present.
15 Georgia Association of Manufacturers.
16 MR. JONES: Good morning, Madam Chair. Clay
17 Jones.
18 MADAM CHAIR PRIDEMORE: Thank you, Mr. Jones.
19 Georgia Coalition of Local Governments.
20 MS. BROWN: Good morning, Madam Chair. Alicia
21 Brown on behalf of Georgia Coalition of Local
22 Governments.
23 MADAM CHAIR PRIDEMORE: Thank you, Ms. Brown.
24 Georgia Conservation Votes.
25 UNIDENTIFIED FEMALE: Good morning. We request

1 excusal. Deborah is not able to make it today.

2 MADAM CHAIR PRIDEMORE: Okay. So we're going

3 to mark you present but excused.

4 UNIDENTIFIED FEMALE: Thank you.

5 MADAM CHAIR PRIDEMORE: Georgia Interfaith

6 Power and Light.

7 MS. WHITFIELD: Good morning, Madam Chair.

8 Jennifer Whitfield on behalf of Georgia Interfaith

9 Power & Light.

10 MADAM CHAIR PRIDEMORE: Thank you,

11 Ms. Whitfield.

12 Georgia Solar Energy Association, GA Solar.

13 GA Solar.

14 MR. MORELAND: Good morning, Don Moreland for

15 Georgia Solar.

16 MADAM CHAIR PRIDEMORE: Thank you,

17 Mr. Moreland.

18 Georgia Solar Energies Association, Georgia

19 Solar Energies Association and Vote Solar. We're

20 going to go GASEIA --

21 MR. THOMASSON: GASEIA, yes, ma'am.

22 MADAM CHAIR PRIDEMORE: -- for short.

23 MR. THOMASSON: Scott Thomasson for GASEIA.

24 MADAM CHAIR PRIDEMORE: Georgia Watch.

25 (No Response.)

1 MADAM CHAIR PRIDEMORE: Georgia Watch.
2 (No Response.)
3 MADAM CHAIR PRIDEMORE: She was tardy last time
4 too. Georgia Watch.
5 (No response.)
6 MADAM CHAIR PRIDEMORE: All right. She gets to
7 go tomorrow.
8 Interstate Gas Supply.
9 MR. STONE: Good morning, Chuck Stone for
10 Interstate Gas Supply.
11 MADAM CHAIR PRIDEMORE: Thank you, Mr. Stone.
12 The Kroger Company.
13 MR. BOEHM: Good morning, Madam Chair. Kurt
14 Boehm for The Kroger Company.
15 MADAM CHAIR PRIDEMORE: MARTA.
16 MS. STURM: Good morning, Kasey Sturm for
17 MARTA.
18 MADAM CHAIR PRIDEMORE: Thank you, Ms. Sturm.
19 Resource Supply Management.
20 MR. CLARKSON: Jim Clarkson for Resource
21 Supply.
22 MADAM CHAIR PRIDEMORE: Thank you,
23 Mr. Clarkson.
24 Sierra Club.
25 MS. ARIZA: Good morning, Commissioners.

1 Isabella Ariza and Robert Jackson on behalf of the
2 Sierra Club.

3 MADAM CHAIR PRIDEMORE: Thank you, Ms. Ariza.
4 Southern Alliance for Clean Energy and
5 Southface Institute.

6 MR. JONES: Good morning. Craig Dowdy, Steven
7 Jones on behalf of Southface and SACE.

8 MADAM CHAIR PRIDEMORE: Thank you, Mr. Dowdy.
9 We're going to call that SACE from this point
10 forward.

11 All right. Southern Renewable Energy
12 Association.

13 (No Response.)

14 MADAM CHAIR PRIDEMORE: Southern Renewable
15 Energy Association.

16 (No Response.)

17 MADAM CHAIR PRIDEMORE: Southern Renewable
18 Energy Association.

19 (No Response.)

20 MADAM CHAIR PRIDEMORE: Not present.
21 United States Department of Defense and all
22 other Federal Agencies.

23 MS. MEDLYN: Good morning, Emily Medlyn.

24 MADAM CHAIR PRIDEMORE: Hello, Ms. Medlyn.
25 We're going to call this USDOE. Is that good? Okay.

1 Utility Management Services.

2 (No Response.)

3 MADAM CHAIR PRIDEMORE: Utility Management

4 Services.

5 (No Response.)

6 MADAM CHAIR PRIDEMORE: Utility Management

7 Services.

8 (No Response.)

9 MADAM CHAIR PRIDEMORE: Not present.

10 According to my addition, we have 17 parties

11 here present today. All right.

12 VICE CHAIRMAN ECHOLS: Madam Chair?

13 MADAM CHAIR PRIDEMORE: Yes, Commissioner

14 Echols?

15 VICE CHAIRMAN ECHOLS: I do have a Smokey and

16 the Bandit quote.

17 MADAM CHAIR PRIDEMORE: Okay.

18 VICE CHAIRMAN ECHOLS: And you can just see if

19 the shoe fits here. This is Burt Reynolds talking to

20 Jerry.

21 MADAM CHAIR PRIDEMORE: Okay.

22 VICE CHAIRMAN ECHOLS: It says: For the good

23 old American life, for the money, the glory, and the

24 fun, mostly the money.

25 MADAM CHAIR PRIDEMORE: Well chosen. Good job.

1 All right. Excellent.

2 We're going to go through housekeeping matters
3 after we do the public witness section, just because
4 lots of times the housekeeping matters appear to you
5 as you're listening to the public witnesses. So if
6 there's no objections, let's start with public
7 witnesses.

8 First, Shaunda Freeman. Good morning,
9 Ms. Freeman.

10 MS. FREEMAN: Greetings, everyone in this room;
11 right? Hope y'all are feeling phenomenal, because I
12 am. Again, my name is Shaunda Freeman. I am a
13 32-year-old woman with two young sons, and I am a
14 native of Atlanta, Georgia. Born and raised here.
15 I'm a Grady baby, I'm an ATLM.

16 I just remember growing up as a kid here right
17 now, 75/85, seeing the Georgia Power building and now
18 it's the Southern Company, but just being a native
19 here of Georgia, right, of Atlanta. So I'm here
20 today because I'm taking out time from my 73, J-O-B,
21 which is an elementary school for Fulton County
22 schools to express my frustration and this thing for
23 the Southern Company and Georgia Power because they
24 want to raise this rate that would add \$14 to our
25 bill or \$750 a year.

1 And so I just want to understand why. I don't
2 understand why Georgia Power is wanting to take more
3 money from my household to compensate for a project
4 that they claim will be better for clean, reliable
5 energy for the millions of Georgians. But real
6 quick, do you know even know what J-O-B really is? A
7 J-O-B is "just over broke." Just over broke. And
8 many of us are already having difficulties making
9 ends meet.

10 So now Georgia Power is wanting to take the
11 additional money out of my household, and millions of
12 Georgians' households and for what? A nuclear power
13 plant that's in Waynesboro, Georgia, that's two and a
14 half hours from Atlanta? How does that really add
15 value to me and my community here in Atlanta?

16 So before I came here, heard about this hearing
17 on my Community Radio, 89.3, thankfully for the
18 Community Radio, I did a little research about this
19 project, and so I found that in the second quarter of
20 this year, 2022, that Southern Company, they profited
21 \$1.1 billion.

22 And so to begin this project of Plant Vogtle to
23 see its development and construction, Plant Vogtle
24 was provided more than \$12 billion from the US
25 Department of Energy and loan guarantees, and that

1 came directly from Georgia Power Company's website.
2 Now, with all of these profits and loans, why is more
3 money needed from the millions of Georgians? This is
4 what's frustrating me.

5 You know, as we all know that in America is
6 business, and we know that without business we would
7 have nothing nor be nothing. Quote that from Sister
8 Soldier. So being African American and understanding
9 that my kidnapped ancestors came from Africa to be in
10 chattel slavery, now in this present day, I feel like
11 I'm a slave. I feel like a million Americans are
12 slaves, because we are continuing to have money taken
13 from us and requiring more from our efforts so that
14 companies and corporations can continue to capitalize
15 and make a profit.

16 Will we receive any dividends or discounts from
17 this investment since we're having to spend an
18 additional \$14 a month, or \$750 a year, to help pay
19 for these extra costs of this project? So my
20 question is, why can't the profits be used and
21 reinvested? If it's truly beneficial to me and my
22 household and the millions of Georgians, then there
23 will be a return on this investment from this
24 benefit.

25 And my last question is, who is really

1 benefiting? Who is this really good for? Because
2 it's not for me. It's not for my household. It's
3 not for my children, and it's not for my community.
4 And who is it really going to impact? And that's all
5 I want to say, guys. So I thank y'all for your time

6 MADAM CHAIR PRIDEMORE: Thank you, Ms. Freeman.
7 Happy holidays.

8 THE WITNESS: Y'all too.

9 MADAM CHAIR PRIDEMORE: Keith Duncan.

10 MR. DUNCAN: Good morning to the Public Service
11 Commission. We're actually with the US Press
12 Association. Our name is Keith Duncan. What we're
13 presenting today is a system that requires some
14 additional face to face. We're the most prolific
15 inventors in world history on energy manufacturing.
16 So today we're going to present
17 SolutionsSafeWater.org and Turnofflights.com, so that
18 we can build hydro water power plants in the mountain
19 areas and provide cold water turbine power. It also
20 includes freenuclear.org. So we want to -- that's
21 all we need to say for right now. We just need
22 additional conversation later. So this is our
23 package to present.

24 MADAM CHAIR PRIDEMORE: Please give that to the
25 executive secretary and our offices will be in touch

1 with you.

2 MR. DUNCAN: Thank you. And God bless you.

3 MADAM CHAIR PRIDEMORE: Thank you. Happy
4 holidays.

5 Aretta Baldon.

6 MS. BALDON: Good morning, Madam Chair, and
7 Commissioners. My name is Aretta Baldon. I'm the
8 vice chair of the Atlanta Board of Education. I'd
9 like to support Georgia Power's Make Ready program
10 and their EV charging infrastructure request in this
11 proceeding. To take full advantage of the
12 opportunity afforded to Georgia public schools
13 through federal funds, school districts need charging
14 infrastructure and technical assistance in what is
15 often a novel technology, especially if they are to
16 reap the monetary benefits of using buses as grid
17 energy resources.

18 The EPA's Clean School Bus Program is
19 disbursing \$5 billion over the next five years for
20 public schools to buy clean buses. This program
21 allows rural and low-income public school districts
22 to receive up to 350,000 per EV school bus, and up to
23 25 school buses; however, the Clean School Bus
24 Program provides very limited funding for charging
25 infrastructure and this money must be spent entirely

1 behind the meter and is scaled only to the initial
2 number of buses awarded.

3 There are no funds to build the line extensions
4 and upgrades to power school bus barns. If schools
5 are required to pay out of pocket to support line
6 extensions, if they can only build the infrastructure
7 for the initial bus awards and if they do not have
8 the technical savvy to take full advantage of the
9 program, the promise of unprecedented funding for
10 school buses could be a new additional burden for
11 schools that are located in rural, hard-to-reach
12 districts, and low-income districts.

13 Georgia Power's Make Ready Program request
14 should be approved and schools should be prioritized
15 to receive those funds.

16 Additionally, Georgia Power should be directed
17 to provide the technical assistance that school
18 districts will need to electrify, including
19 assistance in applying for federal funds.

20 There are many reasons why fully funding
21 Georgia Power to play these roles is in the public
22 interest. To deny utility investments in these areas
23 could effectively deny rural schools and schools
24 located in the lower-income areas the chance of
25 transitioning to clean school buses.

1 Students, drivers, and members of the community
2 would continue to be exposed to the significant
3 amounts of harmful diesel emissions like particulate
4 matter and nitrogen oxide that cause asthma and other
5 health problems. The air inside diesel-fueled school
6 buses is worse than the air outside of it, which
7 means that millions of children in Georgia are
8 breathing in large doses of toxic pollution on their
9 commute to and from school.

10 School districts need to be shielded and
11 children protected from gas price volatility. And
12 EPA's program prioritizes school districts that,
13 among other things, have higher rates of poverty and
14 are rural and are on tribal lands. Nearly 150 school
15 districts in Georgia will be prioritized to receive
16 clean school bus funding because they're located in
17 low-income areas where 20 percent or more students
18 are living in poverty.

19 Thank you for listening. Thank you for your
20 time, and have happy holidays.

21 MADAM CHAIR PRIDEMORE: Thank you, Ms. Baldon.
22 I'm going ask our PIO, Tom Krause, to give you my
23 contact information. Reach back out to me about
24 this. I applaud what you guys are doing at APS.
25 You're doing a good job. Thank you.

1 MS. BALDON: Thank you so much.

2 MADAM CHAIR PRIDEMORE: Tonia Coventry-Strader.
3 Tonia Coventry-Strader.

4 Did I get that right?

5 MS. COVENTRY-STRADER: You did.

6 MADAM CHAIR PRIDEMORE: Thank you,
7 Ms. Coventry-Strader.

8 MS. COVENTRY-STRADER: I'm here on behalf of
9 Mothers and Others For Clean Air. I am the executive
10 director, and I just wanted to say, while you're
11 making all of these decisions, please consider the
12 welfare of our children. When my child was three
13 years old, I was on the playground with her one May
14 day. She ran up to me, her eyes were wide, she
15 couldn't breathe, her lips were starting to turn
16 blue. She was having an asthma attack.

17 I later learned from the doctor that this was
18 very common in Atlanta. In fact, in Georgia it was
19 the number one state for children's asthma at the
20 time. That is how I got involved in climate change.
21 I also learned from my doctor that especially hot
22 days are very dangerous because of ozone and PM2.5s
23 in the air, and diesel school buses are also very
24 dangerous for children with asthma.

25 In fact, there's been a couple of cases of

1 children who have died from standing next to school
2 bus fumes and having an asthma attack and no one knew
3 how to help them at that point, unfortunately.

4 What I am just urging you as our Public Service
5 Commission to do is to think about the health and
6 welfare of our children in Georgia and support the
7 ability for our school systems that Aretta just spoke
8 about to do the full transition from diesel to clean
9 electric school buses through Georgia Power, and also
10 to carefully consider the rate base because the same
11 parents who are suffering because their children have
12 asthma, those children are missing a lot of school.

13 We're already having issues with children and
14 learning deficits in schools because of COVID. Those
15 are the very same children who are more susceptible
16 to COVID and to RSV, and those parents are working
17 very, very hard to give their children the best that
18 they can. And I just can't even imagine the decision
19 of having to choose between buying your child's
20 medicine or putting food on the table that some of
21 these parents are having to make.

22 I am so privileged and lucky that that was not
23 a choice I had to make when my child had asthma, but
24 there are a lot of parents in this state who are
25 really struggling with some of these choices they

1 need to make. I thank you very much. This is a
2 matter of life and breath for our children.

3 Thank you. Have a good day.

4 MADAM CHAIR PRIDEMORE: Thank you,
5 Ms. Coventry-Strada. Happy holidays.

6 Kacey Venning.

7 MS. VENNING: Good morning.

8 MADAM CHAIR PRIDEMORE: Good morning.

9 MS. VENNING: My name is Kacey Venning. I lead
10 an organization here on Atlanta's west side. I'm a
11 youth and education advocate and community leader,
12 and we serve some of the most vulnerable youth and
13 their families. Our work to provide wrap-around
14 services and support becomes more challenging with
15 the rising energy costs and barriers to receive the
16 support needed to help keep up with those costs and
17 pay bills on time.

18 Some of the families that we serve are dressing
19 their children in the dark. We know that when the
20 lights are off, it can impact access to natural gas
21 and to water, and the bills are not being paid simply
22 because of laziness or a lack of concern on their
23 part. Many of the adults and the older youth work
24 multiple jobs and it's still not enough, because
25 costs are rising and the income is not, at least, not

1 for those who are living in poverty.

2 But I understand that there are times where we
3 may not feel that is our individual concern, but it
4 must be our collective concern. And while you may
5 think it is a separate issue, the decisions that you
6 make here today are part of a larger organism that
7 feed off of each other.

8 This affects housing costs, academic
9 achievement, which we know directly impacts the
10 ability to earn a sustainable and livable wage, and a
11 city that unfortunately seems to keep pushing them
12 out. And contrary to what any of us may want to
13 believe, it also impacts public safety and crime. It
14 is interconnected and for the least of these, even if
15 that is not our personal story.

16 How can we move the city, this region, and the
17 state forward if we neglect the families and youth we
18 serve because we're able to drive past them and go
19 home where we're able to comfortably pay our bills.
20 I implore you to insert into your business matrix for
21 decision-making, care, concern, and compassion as we
22 work towards a more equitable society. Because if we
23 believe that adults should find their own way, then
24 at least let's consider the children and youth who
25 are being affected.

1 Today is giving Tuesday, and so I implore you
2 that as we begin to work through these things, at
3 least find an organization that you can donate to as
4 they work to lessen the effects of poverty and the
5 decisions that are made in rooms like these.

6 Thank you so much.

7 MADAM CHAIR PRIDEMORE: Thank you, Ms. Venning.
8 Happy holidays.

9 MS. VENNING: Same to you.

10 MADAM CHAIR PRIDEMORE: Linda Pritchett.

11 MS. PRITCHETT: Good morning. My name is Linda
12 Pritchett, and I am a resident of the great city of
13 south Fulton. I live in District 7, and I'm
14 currently a candidate for District 7 City Council.

15 District 7 has a Georgia Power facility there,
16 just mentioning that. I'm here today to appeal to
17 all of you about this issue with the rate hike or the
18 proposed rate hike. I would like to point out that
19 we've just came out of a pandemic, or we're hopefully
20 through with that, but a lot of people have been
21 distressed financially through this pandemic. A lot
22 of people worked in financial distress before the
23 pandemic.

24 It seems to me that this rate hike is
25 unnecessary, that you're asking the consumers to

1 correct something that should have been corrected at
2 the corporate level. I am personally tired of seeing
3 companies making record profits, whether it be fuel
4 or energy. And I just don't think that it should be
5 on our backs when good people that work every day,
6 that go to work 9:00 to 5:00, are not getting
7 increases in their wages.

8 I just want to appeal to you to ask you to
9 reject this proposal because it will hurt people. In
10 my community specifically in District 7, we are a
11 residential community. We don't have -- we only have
12 like one apartment complex, so these are people who
13 are homeowners. They will be negatively impacted by
14 this rate hike.

15 We have programs that we're aware of like
16 LIHEAP, which are utility programs that gives
17 assistance to people. The people in my city, I'm not
18 saying that we're poor people. I'm not saying that
19 we're low income people. I think that we're just
20 average people that go to work and just want to enjoy
21 a quality of life.

22 I implore you not to not consider this, to find
23 another way, another avenue. And if you do consider
24 it, in the alternative, to make Georgia Power put in
25 place some type of assistance or some type of waiver,

1 something to help people that can simply not afford
2 this rate hike to, you know, put something in place.
3 And also to restrict executives from continuing to
4 get bonuses and all these profits.

5 You have to reinvest in the communities. We
6 have Georgia Power in my community, and I insist that
7 they reinvest and that they stop taking advantage of
8 us and making us pay for mistakes that we have
9 nothing to do with. We cannot go without power.
10 It's something that -- food, shelter, and utility is
11 an essential. Thank you so much.

12 MADAM CHAIR PRIDEMORE: Thank you,
13 Ms. Pritchett. Happy holidays.

14 MS. PRITCHETT: Likewise.

15 MADAM CHAIR PRIDEMORE: Robert Jones.

16 MR. JONES: Good morning. And thank you for
17 the opportunity to address the Commission.

18 MADAM CHAIR PRIDEMORE: Good morning.

19 MR. JONES: Substitute math teacher, so I teach
20 advanced algebra and geometry. I have not had the
21 opportunity to read all of the testimony and
22 rebuttals that have been submitted in this docket, so
23 I've relied upon the comments I've seen in the last
24 couple of months, looked at the Southern Company's
25 most recent earnings report, and I looked at the most

1 recent Fitch Ratings on Southern Company's and
2 Georgia Power's bond ratings.

3 I have three comments I would just offer this
4 morning from a citizen's standpoint. I don't have
5 the expertise of the people in this room. You have
6 enough intervenors there, I think they can cover most
7 of the points.

8 The comments I want to make really relate to
9 demand forecasting. Second, is Georgia Power's
10 request in terms of their range on return on equity.
11 And third is the renewable and nonrenewable tariff.

12 On the demand forecast piece, as I teach my
13 students, you know, forecast is based on models. And
14 when you do that, you're almost assured of being
15 wrong. So, therefore, I would ask that the
16 Commission really look at the forecast that was
17 submitted from the demand standpoint, and view those
18 as probably being too conservative.

19 The regulatory process incentivizes utilities
20 to present a conservative demand forecast that leads
21 to lower units, higher rates from a unit cost
22 standpoint, faster cost recovery. Southern Company
23 admitted in their third quarter earnings report,
24 their electricity sales far outpaced what their
25 forecasts were that allowed them to really increase

1 their earnings.

2 They have very attractive dividend margins from
3 a financial standpoint. I'm not an investor in
4 Southern Company, but what they're proposing right
5 now if they receive that, I might be one very quickly
6 there. I think where they are financially is
7 probably out of line with where the market realities
8 are for other companies that are in a competitive
9 market.

10 And so what they're seeking there, I would ask
11 you to really take a hard look at and balance that in
12 terms of what their needs are for cost recovery, a
13 reasonable rate of return, and also in terms of
14 consumers and businesses from that standpoint.

15 The return on equity portion of the -- I think
16 it's a 9.5 to a 12 percent range they're seeking.
17 Everything I've learned in finance -- I'm no expert
18 in finance -- you've got from the room here is, if
19 you have 8 percent return on the market, feel good
20 about it. 9.5 to a 12 percent on equity seems to be
21 excessive from an investment standpoint.

22 I also understand according to the Fitch
23 Report, you're seeking that if they go above that,
24 80 percent of that that goes above it will be shared
25 back with the consumers and the businesses.

1 20 percent they would keep. That means that either
2 12 percent could go to 12 or 15 percent on a return
3 of equity standpoint.

4 Again, seems totally excessive and out of line
5 with really market realities, so I would ask you as
6 commissioners to really tamp that down and balance it
7 to where we are in terms of economics of the general
8 public there.

9 Seven seconds remaining. Georgia is not
10 California. Please continue with the renewable/
11 nonrenewable tariff. Do not cap that. let's
12 incentivize when homeowners put solar on their roofs
13 and let them sell it back to the utility.

14 Thank you for the time. I think I made it
15 within your limits there. Appreciate it.

16 MADAM CHAIR PRIDEMORE: You did fine,
17 Mr. Jones. Happy holidays.

18 MR. JONES: Thank you.

19 MADAM CHAIR PRIDEMORE: Patty Durand.

20 MS. DURAND: Mr. Jones mostly was using
21 understatements because he doesn't know the reality
22 that Georgia Power is receiving far above industry
23 standards for return on equity. Nobody likes being
24 overcharged for a service, especially when they don't
25 have choices of who to buy that service from. That's

1 exactly what we Georgia Power customers have.

2 Utilities, Georgia Power, often claim higher
3 returns are necessary to attract capital and operate
4 a strong business. This is a lie. This is a lie
5 that, Commissioner Echols, you frequently repeat,
6 but, in fact, all other utilities in the country
7 earning much lower ROE than Georgia Power does. And,
8 in fact, the savings from Georgia Power's reduced
9 ROE, had they gotten industry average, would have
10 saved Georgia Power customers \$7 billion over the
11 past ten years, and \$2 billion just since the 2019
12 rate increase when this Commission authorized them a
13 crazy high 10.5 ROE. That's just the baseline, as
14 the previous speaker said. It got much higher than
15 that. But that would require you-all to regulate in
16 the public interest, and you're not doing that.

17 Let me move on to rates, because that's just
18 ROE. The mission of the Georgia Public Service
19 Commission claims on your website that it's to
20 exercise its authority and influence to ensure that
21 customers receive safe, reliable, and reasonably
22 priced electric services, but you aren't doing that
23 either, are you?

24 Because if you were, you wouldn't have passed
25 the residential demand charge rate plan that Georgia

1 Power falsely calls smart usage. It actually doubles
2 rate bills for low use energy users on that rate
3 plan. And you literally haven't done your job by
4 requiring a customer impact study on that rate plan,
5 not in 2019 when you authorized it, and not in 2022
6 even though the 2019 settlement order required that
7 plan -- I mean, study to be done.

8 And you didn't do it because you didn't want to
9 know the results, which would be that low use energy
10 users would be paying a lot more on their bills than
11 if they were on a traditional rate plan, which
12 Georgia Power is outrageously asking to withdraw. So
13 you don't want to have that documented, so you
14 haven't done the study and so we've had to allow
15 intervenor studies, which would show those facts.

16 I don't know how you sleep at night, especially
17 you, Commissioner Pridemore, claiming this Commission
18 is one of the best regulated utilities in the nation.
19 It's clearly not. Customers paying double what they
20 should be is clearly not good regulation. Allowing
21 Georgia Power to have crazy high return on equity,
22 far above other utilities, is clearly not good
23 regulation.

24 And having people pay the highest energy bills
25 in the nation, which is going to result from this if

1 you give everything Georgia Power wants, is clearly
2 not good regulation.

3 And, Commissioner Echols, you claim to be a
4 watchdog for Georgia families on your website. Are
5 you watching bills double? Is that what you're
6 watchdogging? Because you're not watchdogging
7 protecting the public interest. So shame on all of
8 you.

9 Not you, Commissioner McDonald, because you
10 voted against the last rate case, so good for you.

11 MADAM CHAIR PRIDEMORE: Happy holidays,
12 Ms. Durant.

13 Scott Starowicz.

14 MR. STAROWICZ: Good morning. My name is Scott
15 Starowicz. I'm the CFO and founder of the SAE
16 School. The SAE School is a 501(c)(3) nonprofit
17 school in the South Cobb area. We serve more than
18 400 students preschool through eighth grade. Our
19 school is an affordable private school that educates
20 students through project-based learning.

21 In addition, we're a year-round school that has
22 a sustainability theme and we incorporate this into
23 our curriculum and our facilities. In regards to the
24 sustainability theme, our school has made significant
25 investments into energy-efficient upgrades. We have

1 LED lights throughout our building. We have
2 energy-efficient HVAC units, and we're the first
3 school to be a hundred percent solar in Georgia. Our
4 school has 156 kW solar panels that were installed in
5 2020.

6 I want to draw a couple of items to your
7 attention that have affected us directly: The
8 minimum monthly bill and the environmental compliance
9 costs.

10 In February of 2021, we received a bill from
11 Georgia Power showing that we consumed 7,880 kilowatt
12 hours of energy from the grid, and during that same
13 time period we exported back 8,200-kilowatt hours
14 back into the grid. During this month, we were net
15 zero; however, the bill we received for the month was
16 \$744 due to the minimum billing requirements. Our
17 school is on the medium power and light rate plan.

18 When our school decided to make this investment
19 with energy-efficient upgrades and solar panels, the
20 idea was for us to produce clean energy and
21 recuperate our investment over time due to the
22 reduction on our utility bill. And monthly we
23 produce more power than we consume. I don't believe
24 it's right that we still had to pay a bill that was
25 over \$700.

1 Our organization -- our goal as an organization
2 is to educate students and by paying these bills it
3 takes away funds that could have otherwise gone
4 towards our mission. My ask is for nonprofits is
5 that the minimum monthly bill either be removed or
6 simplified going forward.

7 Our organization consulted with Creative Solar,
8 Southface Institute and the Bill and Melinda Gates
9 Foundation. Our organization took all of the
10 appropriate steps to ensure that our investment would
11 make financial sense prior to making the investment.
12 But nevertheless, the minimum monthly bill is based
13 on a complex formula that makes it hard to predict
14 and understand.

15 Through the help of our partners, we recently
16 looked at alternative plans and demand management
17 practices and in combination should bring our future
18 energy expenses within our expectations.

19 The one last item that I find difficult to
20 rationalize for any organization trying to reduce
21 their carbon footprint, whether they are a nonprofit
22 or a for-profit is the environmental fee. This is an
23 extra 18 percent that was added on top of the basic
24 charge. In a regular scenario if one reduces
25 consumption, then one would expect the environmental

1 compliance to be proportionately reduced. However,
2 when minimum monthly bill is applied, one can end up
3 paying hundreds of dollars in environment compliance
4 fees when, in fact, there was no net consumption of
5 energy from the grid.

6 During February of '21, we, at our school, were
7 charged an environmental fee of 18 percent on energy
8 that we produced with clean solar panels. In other
9 words, we have a solar panel array system that
10 produces zero carbon emissions in a month and we are
11 still being charged an environmental cost incurred by
12 Georgia Power. There should be no environmental
13 compliance fees imposed on customers that on a
14 monthly basis export more renewable energy to the
15 grid than what we are taking from it.

16 I appreciate the opportunity and your time.

17 MADAM CHAIR PRIDEMORE: Thank you,
18 Mr. Starowicz. Happy holidays.

19 Wan Smith.

20 MS. SMITH: Good morning. I wasn't going to
21 speak this morning, but after Commissioner Echols'
22 comments, his Smokey and the Bear reference, I
23 thought it necessary to address and kind of recenter
24 us.

25 Again, as in my previous statements, I am not

1 here to ask for a favor or benevolence, but to remind
2 you of your oath and values that I've heard many of
3 you espouse, whether it's on social media, in this
4 hearing room, on your social medias, or publicly
5 since I began this work in 2017.

6 Again, I am here to remind you of your oath and
7 the values that I've heard you all espouse. I have a
8 reference, too, this morning Commissioner Echols.
9 It's a Christian reference. I think I've heard all
10 of you espouse at one point or another that you are a
11 follower of the Way. All things are lawful, but all
12 things do not edify.

13 I have a second reference. It's tone deaf: A
14 condition of being oblivious and/or clueless or
15 indifferent regarding the assistance of social cues,
16 nuances, morals, norms, et cetera, within a given
17 social subset or more often than not totally and
18 completely all the time.

19 Your comment, Commissioner, was out of line and
20 tone deaf when we are talking about raising bills and
21 giving Georgia profit -- Georgia Power record
22 profits. We are talking about turning off lights.
23 We are talking about people going without and to
24 make -- and it's clear that this was, you know -- I
25 mean, perhaps a, what do they call it?

1 VICE CHAIRMAN ECHOLS: Joke?

2 MS. SMITH: No. This is a serious matter.

3 This is a serious matter. They call it a Freudian
4 slip. It's not called a joke. It's called a
5 Freudian slip out of the abund- -- we're Christians,
6 right? Out of the abundance of the heart, the mouth
7 speaks.

8 And so indifference for this hearing, with a
9 modicum of decorum, it was inappropriate when we're
10 talking about turning off lights. And to make a joke
11 about it being all about the money when the big guys
12 are here asking for more money, it says you're tone
13 deaf. And just because you can doesn't mean you
14 should; right?

15 So as you know, there was a statement about how
16 we should conduct ourselves as speakers if we're
17 going to come in here. I think we should all hold
18 ourselves to the same standard. And I think that we
19 should, you know, reconsider our approach to the
20 seriousness and the veracity of the decisions you
21 have to make. Because you shouldn't be -- this is
22 not a joke.

23 And if you think it's a joke -- I don't know,
24 you know. I mean, if you think this is the time to
25 joke or play, if you think this is a laughing matter,

1 something is wrong. Something is wrong if you think
2 this is a laughing matter. Thank you.

3 MADAM CHAIR PRIDEMORE: Trish Naghise -- Tish
4 Naghise.

5 Let me first say, Ms. Naghise, congratulations
6 on your victory for your state house seat. What
7 district will you be serving?

8 MS. NAGHISE: 68, which is two counties, Fulton
9 and Fayette, which I live in Fayette, and thank you
10 for that.

11 I am standing before you as a newly elected
12 representative for House District 68, and as I went
13 around campaigning, I spoke with a lot of my
14 constituents, and they also was concerned about the
15 high bills that they're already receiving from
16 Georgia Power, and they wanted me to say that they're
17 not going to be able to afford it. They already have
18 their bills. I saw some of them were like 300, 400,
19 and this is a working community.

20 As I stated, I have Fayette, Tyrone, and
21 Peachtree City, and some of the people even that live
22 there in Peachtree City may be more affluent, but
23 they still have issues with increase in their rate
24 from Georgia Power. They're still going through
25 inflationary rates for everything from gas to meat,

1 chicken, \$17 for chicken. It's just very not
2 affordable right now at this time for my
3 constituents.

4 I have constituents in Fulton County which
5 is -- City of South Fulton, College Park area, and
6 Union City, and those people are also suffering as a
7 result of that. They work really hard. They're --
8 most of them are two-family homes, and two members
9 working in the home. And as a result of that,
10 they're still not making the -- the bills that they
11 need to pay every month.

12 And they do not want to be lacking or behind in
13 their bills. They just want to be able to go to
14 work, raise their children, have their children go to
15 school, and be able to afford the things that they
16 need. So especially with the kids in school having
17 access to computers, electronics, and all of those
18 things that other people have.

19 So an increase at this particular time would
20 not be advantageous to my community. So I just came
21 to speak on their behalf to just say, please look
22 into the fact that Georgia Power just recently got an
23 increase in 2019. Of course, we need the grid. Of
24 course, we need a lot of the things, upgrades that
25 Georgia Power have, but we also want to make sure

1 that it is equitable and it is equality across the
2 spectrum of where and how that money is spent if
3 you're granted to them. Thank you, and thank you
4 again

5 MADAM CHAIR PRIDEMORE: Thank you, Ms. Naghise.
6 Happy holidays to you.

7 MS. NAGHISE: Thank you.

8 MADAM CHAIR PRIDEMORE: Tegveer Uppal.

9 MR. UPPAL: Good Morning. My name is Teg. I'm
10 a health services and health economics researcher
11 with a master's in public health and health policy
12 from Emory University. I'm here to speak against the
13 proposed rate hikes on behalf of low-income people in
14 Georgia. Rate hikes would increase the energy
15 burden. The cash spent per paycheck on electric
16 bills. As costs of living have risen these past few
17 years, people are increasingly making difficult
18 household economic decisions, and any proposed rate
19 hike could force Georgians to make the choice between
20 to heat or to eat, and also the choice to heat or to
21 purchase life-saving medication.

22 Low-income people are more likely to live in
23 housing with poor insulation, older homes and
24 outdated appliances which disproportionately expose
25 them to greater cost burdens.

1 And let me be clear, this is a matter of
2 equity. Black and brown communities in the Southeast
3 face the highest energy burdens in the country. And
4 it will be Georgians at the margins who suffer while
5 Georgia Power profits.

6 I learned recently about rental restrictions on
7 utility disconnections. If Georgians can't pay their
8 bills, they can be at risk of homelessness.

9 Housing security is a major driver for health.
10 When people do not have access to housing, they're at
11 greater risk for negative health outcomes, including
12 worsening disease, complications and premature death.

13 My last rental, a studio apartment in Atlanta,
14 was poorly insulated. And last year I saw my own
15 electric costs increase to 200 to 300 a month to keep
16 my thermostat reading over 45 degrees in the winter.
17 I was lucky enough to afford those expensive winter
18 months, but many aren't.

19 A paper published by the National Bureau of
20 Economic Research in 2019 found that lower heating
21 prices reduces deaths in the winter, while other
22 research shows that low income people are more likely
23 to avoid using AC during heat waves and suffer heat
24 complications at greater rates.

25 Years ago as a student I remember being shocked

1 that the life expectancy in Metro Atlanta and certain
2 areas fell below the average of Sub-Saharan Africa.
3 Yesterday, the AJC reported that the Atlanta Metro
4 area has the greatest income inequality in the United
5 States.

6 Time and time again in my research, I see
7 disparities in minority communities in terms of
8 greater risk to mortality, disease, and healthcare
9 use, and I've grown to understand that these issues
10 are systemic. A rate hike would perpetuate the
11 differences between the haves and the have-nots here
12 in Georgia, and expose millions to inhumane
13 conditions.

14 The system is right here in this room and I'm
15 looking at it, and the Commission has the duty to act
16 in the best interest of the people and for the health
17 of all Georgians. Thank you.

18 MADAM CHAIR PRIDEMORE: Thank you, Mr. Uppal.

19 Vincent Fort.

20 MR. FORT: Let me try to figure out my document
21 here for a second. Let me just begin by saying good
22 morning, Madam Chair, and members of the Commission.
23 My name is Vincent Fort. I live here in Atlanta, and
24 I don't know an ROE from a kilowatt hour. I'm just
25 very impressed by learned folk that have been to this

1 microphone in the last few minutes, but what I do
2 know is when folk are having hard times. I do know
3 that.

4 I know that recent research has shown that 60
5 percent of households live paycheck to paycheck, and
6 I know that -- and this has been well documented,
7 that families who have a \$400 emergency, the number
8 of people who have a \$400 emergency would put them
9 into poverty, would create a crisis that could lead
10 to many things, including homelessness as well as
11 getting their power cut off. This is a serious
12 issue. This is not an issue for joking.

13 I think the real story, though, and the
14 mainstream media has not reported it, you know, this
15 12 percent increase is one thing, but I've been doing
16 a little research. Google is a great thing, that
17 Google. And I've been doing some research and my
18 research shows that Georgia Power over the next two
19 to three years will be coming back for probably as
20 much as another 45 percent or enough increases to --
21 in the rates for 45 percent increase that people are
22 going to have to have. That's the real story, and I
23 hope the media has been watching, because it hasn't
24 been reported locally.

25 If you vote for this, you're about to descend

1 working people in Georgia into a crisis. No two ways
2 about it. And I would hope that you would rethink
3 this and not allow Georgia Power to rig the system.
4 I mean, there's a reason that regular folk, like some
5 of the folk here, think that the system is rigged
6 against them. They think that Georgia Power has a
7 leg up on the PSC. Prove them wrong. Vote against
8 this, and fully inform the public about what's going
9 on here; that this isn't just about 12 percent, this
10 is about 45 to 55 percent.

11 Don't try to fool the people. Tell them the
12 truth. Tell them the truth for the senior citizens.
13 In Georgia 10 percent of senior citizens are deeply
14 food insecure. We're not even talking about
15 children, which is about another 10 percent.

16 When you add what y'all might be doing this
17 month to that burden, it's unconscionable. So I
18 thank you for your time and I appreciate you for what
19 you do, but please don't do this thing. Don't raise
20 these rates on Georgia working people. Thank you.

21 MADAM CHAIR PRIDEMORE: Thank you, Mr. Fort.
22 Happy holidays.

23 MR. FORT: Same to you.

24 MADAM CHAIR PRIDEMORE: Tara Opie.

25 MS. OPEY: Good Morning. Thank you again,

1 Commissioners, for the opportunity to speak today. I
2 have spoken with some of you in the times. My
3 colleagues and I spoke on this issue, the same issue
4 months ago. I'm ashamed and appalled that this is an
5 issue that has to be addressed once again.

6 My name is Tara Opie and I'm representing the
7 community of small business owners again. With
8 almost 1 million small businesses in Georgia,
9 70 percent fail due to not being able to pay
10 utilities, including electricity, and I am still one
11 of them.

12 I celebrated four years in business in
13 November, and my firm runs remotely and relies on
14 Georgia Power. Increasing the rate to nearly \$200
15 per year by the 2025 will make it impossible to keep
16 up along with the raising rates of all other
17 utilities.

18 I service small business owners and create ways
19 to incorporate better financial practices to ensure
20 that their longevity is in their markets. Budgeting
21 and creating feasible price points are critical for
22 my business. Increasing my rates, as you all are
23 suggesting the last time that we spoke, would be more
24 difficult to maintain my client base and for those
25 who are already stretching their dollars for my

1 services. The need to keep a profit margin for
2 Georgia Power does not equate to how the price hike
3 would be for those who need it most.

4 The company profits across the first six months
5 of 2022 are also up, rising from \$1.5 billion in the
6 first half of 2021 to \$2.1 billion this year.

7 One of the colleagues spoke before me used AJC
8 as a reference, and I will do that also. In July 28,
9 2022, this information was released, which this fact
10 has been responded to as fake news. I implore you
11 to, again, reconsider the structure of this price
12 increase to align with the majority of our customers.
13 Equity will ensure that all will receive service at a
14 rate for those who need it most. Thank you for your
15 time.

16 MADAM CHAIR PRIDEMORE: Thank you, Ms. Opie.
17 Happy holidays.

18 All right. That concludes my list and what the
19 executive secretary has on sign-in. Are there any
20 others that have not signed in?

21 (No Response.)

22 MADAM CHAIR PRIDEMORE: Okay. At this point we
23 will take a ten-minute recess. We will be back in at
24 10:33 a.m.

25 (A break was taken.)

1 MADAM CHAIR PRIDEMORE: Okay. Housekeeping
2 matters, Georgia Public Service Commission, do you
3 have any housekeeping?

4 MR. WALSH: No, we do not.

5 MADAM CHAIR PRIDEMORE: Georgia Power?

6 MR. HEWITSON: No, ma'am.

7 MADAM CHAIR PRIDEMORE: Okay. Any other party
8 have housekeeping?

9 (No Response.)

10 MADAM CHAIR PRIDEMORE: Okay. I do. I've got
11 a couple of things. So this is rebuttal testimony,
12 and then the staff questioning on the RNR portion of
13 the case. I'm going to be real clear here, because
14 the way that the PSO is structured, it's a two-day
15 set of hearings. So your speed and your ability to
16 be efficient is what makes that possible. And that's
17 an important consideration. Although folks from the
18 outside may be like, well, you should just stay there
19 and work 24 hours a day, seven days a week, that's
20 not the issue. There are laws that guide the way we
21 operate hearings, and I want to encourage you, if you
22 don't understand those laws, please refer to our
23 Georgia Legal Code and understand those laws.

24 So it's important that we be efficient, and so
25 a couple of things, which are no different than the

1 ordinary, but just so you're aware, they will be
2 enforced. No duplicative questions, duplicative
3 questions. If your question has been asked, please
4 don't ask it again. you will be stopped.

5 Be prepared with your questions when you come
6 to the lecturn. Please don't be scrolling your
7 phones, scrolling your iPad, looking for your
8 questions, trying to figure out which ones you like
9 the most. Be ready. You have plenty of time to sit
10 there and prepare your questions just like
11 Commissioners have time to prepare our questions.

12 When you pass out exhibits, please pass out
13 your exhibits all at the same time. If you have any
14 demonstrative at all, please get it all out at one
15 time, be efficient, bring a buddy. If you don't have
16 a buddy, a buddy can be assigned to you.

17 All right? Very good.

18 All right. With that, Georgia Power.

19 MR. HEWITSON: Thank you, Madam Chair. At this
20 time Georgia Power calls the panel of Mr. Aaron
21 Abramovitz, Ms. Sarah Adams, Mr. Adam Houston, and
22 Mr. Michael Robinson to the stand.

23 Whereupon,

24 AARON P. ABRAMOVITZ,
25 SARAH P. ADAMS,
ADAM D. HOUSTON,
MICHAEL B. ROBINSON,

1 having been first duly sworn, testified as follows:

2 DIRECT EXAMINATION

3 BY BY MR. HEWITSON:

4 Q Mr. Abramovitz, please start by stating your
5 full name, your employer and your responsibilities for the
6 record.

7 A (Witness Abramovitz) Sure. Aaron Abramovitz,
8 I work for Georgia Power Company, am chief financial officer
9 and treasurer of the company, and my address is 241 Ralph
10 McGill, Atlanta, Georgia 30308.

11 Q Ms. Adams?

12 A (Witness Adams) I'm Sarah P. Adams. I'm the
13 comptroller at Georgia Power Company at the same address,
14 and responsible for all of the accounting functions.

15 Q And Mr. Houston?

16 A (Witness Houston) Good morning. Adam Houston,
17 assistant comptroller at the same address.

18 Q And Mr. Robinson?

19 A (Witness Robinson) I'm Michael Robinson, vice
20 president of planning and operations and policy for our
21 power delivery organization and at the same address.

22 Q Mr. Abramovitz, on November 18 of this year,
23 did you prefile or cause to be prefiled 61 pages of rebuttal
24 testimony in question and answer format in this case?

25 A (Witness Abramovitz) Yes.

1 Q Are there any corrections that you need to make
2 to your prefiled rebuttal testimony?

3 A (Witness Abramovitz) No.

4 Q If I were to ask you the same questions today
5 under oath, would your answers be the same as are set forth
6 in your prefiled rebuttal testimony?

7 A (Witness Abramovitz) They would be.

8 MR. HEWITSON: Madam Chair, a copy of the
9 prefiled testimony was provided earlier to the court
10 reporter, and I would now ask that the rebuttal
11 testimony of the panel be copied into the record as
12 if given here today.

13 MADAM CHAIR PRIDEMORE: So moved.

14 (Whereupon, the prefiled direct testimonies
15 of Aaron P. Abramovitz, Sarah P. Adams, Adam
16 D. Houston and Michael B. Robinson follows:)

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REBUTTAL TESTIMONY OF
AARON P. ABRAMOVITZ, SARAH P. ADAMS, ADAM D. HOUSTON,
AND MICHAEL B. ROBINSON
ON BEHALF OF GEORGIA POWER COMPANY
GPSC DOCKET NO. 44280

I. INTRODUCTION

1 **Q. PLEASE STATE YOUR NAMES, TITLES AND BUSINESS ADDRESS.**

2 A. Aaron P. Abramovitz. I am the Executive Vice President, Chief Financial Officer,
3 and Treasurer for Georgia Power. My business address is 241 Ralph McGill
4 Boulevard N.E., Atlanta, Georgia 30308.

5 A. Sarah P. Adams. I am the Vice President and Comptroller for Georgia Power. My
6 business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

7 A. Adam D. Houston. I am the Assistant Comptroller for Georgia Power. My business
8 address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

9 A. Michael B. Robinson. I am the Vice President of Planning, Operations and Policy
10 for Georgia Power. My business address is 241 Ralph McGill Boulevard N.E.,
11 Atlanta, Georgia 30308.

12 **Q. MR. ABRAMOVITZ, MS. ADAMS, MR. HOUSTON, AND MR.**
13 **ROBINSON, DID YOU PRESENT DIRECT TESTIMONY AND EXHIBITS**
14 **ON BEHALF OF GEORGIA POWER IN THIS PROCEEDING?**

15 A. Yes.

1 **Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

2 A. The purpose of our testimony is to respond to the recommendations of the Georgia
3 Public Service Commission’s (“Commission”) Public Interest Advocacy (“PIA”)
4 Staff and various Intervenors. To the extent this rebuttal testimony does not address
5 a particular PIA Staff or Intervenor recommendation, that should not be construed
6 as support for such position.

7 **Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

8 A. Our testimony requests that the Commission continue the constructive regulatory
9 environment, effectuated through an Alternate Rate Plan (“ARP”), that has
10 benefitted Georgia Power’s customers for decades. This Commission’s
11 constructive regulatory policies have created a sustained period of high customer
12 satisfaction, high reliability, and rates below the national average, and have
13 contributed to Georgia being consistently ranked as the best state in the nation in
14 which to do business. This Commission has a well-deserved national reputation for
15 maintaining a consistent and balanced regulatory environment that benefits all
16 stakeholders. The Commission’s regulatory structure has created an environment
17 in which: (i) the Company can provide the clean, safe, and reliable service that our
18 customers depend on to meet their evolving energy needs; (ii) the Company can
19 access capital on favorable terms to meet the current and future needs of our
20 customers; and (iii) the Company’s investors have an opportunity to receive the
21 returns appropriate for a well-run and efficient utility that meets the needs of its
22 customers.

23 Absent an ARP agreed to by the Company, this case will result in a traditional rate
24 case order, which would eliminate the numerous positive attributes of a three-year
25 predictable rate plan, including any sharing of revenues above the top end of the
26 ARP earnings band. This fact notwithstanding, PIA Staff and several Intervenors
27 have proposed radical and harmful modifications to the ARP. PIA Staff goes so far

1 as to suggest that the Commission impose an earnings cap, which is fundamentally
2 inconsistent with the concept of the ARP sharing mechanism that benefits both
3 customers and the Company. These proposed modifications undercut core aspects
4 of the ARP and, as such, the Commission should reject them.

5 The positions put forth by PIA Staff and several Intervenors would undermine
6 Georgia's well-established and balanced regulatory structure by drastically
7 reducing the Company's return on equity ("ROE"). PIA Staff's recommended 105
8 basis point ROE reduction would represent the largest single ROE reduction for
9 Georgia Power in decades and would be particularly egregious in light of the
10 Company's superior performance over the last three years, including during the
11 COVID-19 pandemic. Many of these same parties also propose to reduce the equity
12 within the Company's capital structure, including PIA Staff's recommended 500
13 basis point reduction from the level deemed appropriate by this Commission just
14 three years ago. Such unprecedented and severe changes would significantly impair
15 the Company's financial integrity, which is necessary to ensure its ability to raise
16 capital at reasonable cost and upon reasonable terms for the benefit of customers.

17 PIA Staff has also asserted that the Company can arbitrarily reduce its Operations
18 and Maintenance ("O&M") expense, as well as substantially reduce or eliminate
19 transmission and distribution investments required to support the long-term
20 reliability and resiliency of our electric system, without considering the long-term
21 impacts to the performance of the electric system for our customers and the state.
22 The Commission must consider the cost of electric service when evaluating Georgia
23 Power's cost to serve our 2.7 million customers, and we have thoughtfully and
24 appropriately balanced our request in this proceeding with both the financial
25 impacts to, and needs of, our customers.

26 The changes that PIA Staff and many of the intervening parties propose are ill-
27 advised and fail to consider the impact of their proposals on the Company's ability
28 to access capital markets on reasonable terms and to attract the substantial capital

1 necessary to continue providing our customers with the clean, safe and reliable
2 electric service they deserve and expect. Therefore, the Commission should
3 approve the rate adjustment and capital structure Georgia Power proposes in this
4 case so that the Company remains positioned to continue meeting the energy needs
5 of our customers and the communities we serve.

6 **Q. HOW IS THE REMAINDER OF YOUR TESTIMONY STRUCTURED?**

7 A. Our testimony is organized as follows:

- 8 • Section II (pages 5 to 14) discusses financial integrity and access to capital;
- 9 • Section III (pages 15 to 19) discusses proposed modifications to the traditional
10 alternate rate plan;
- 11 • Section IV (pages 19 to 21) discusses coal combustion residuals asset retirement
12 obligations (“CCR AROs”);
- 13 • Section V (pages 21 to 23) discusses electric transportation;
- 14 • Section VI (pages 23 to 36) discusses O&M adjustments;
- 15 • Section VII (pages 36 to 39) discusses other issues, including the revenue
16 forecast, compliance filing requirements, and depreciation;
- 17 • Section VIII (pages 39 to 59) discusses the Grid Investment Plan, DERMS, and
18 Rules and Regulations Section G; and
- 19 • Section IX (pages 59-61) discusses recent tax legislation.

20 In addition to our rebuttal testimony, the Company is filing the rebuttal testimony
21 of: (1) Mr. James M. Coyne to address the ROE recommendations and analyses of
22 PIA Staff Witness Gorman and Intervenor Witnesses Pollock, Reno, and Ellis;
23 (2) Mr. Steven Fetter to explain the credit rating impacts of PIA Staff and
24 Intervenor recommendations; and (3) Mr. Larry T. Legg and Mr. Lee Evans to rebut
25 rate design and cost of service issues raised by PIA Staff and Intervenors.

1 **II. FINANCIAL INTEGRITY AND ACCESS TO CAPITAL**

2 **Q. WOULD ADOPTION OF PIA STAFF AND INTERVENOR’S COST OF**
3 **CAPITAL POSITIONS UNDO THIS COMMISSION’S HISTORY OF**
4 **BALANCED, CONSISTENT AND PREDICTABLE REGULATION AND**
5 **HARM THE COMPANY’S FINANCIAL INTEGRITY?**

6 **A. Yes.**

7 **Q. PLEASE EXPLAIN THE IMPORTANCE OF CONSISTENT AND**
8 **PREDICTABLE REGULATION WITHIN THE CONTEXT OF INVESTOR**
9 **AND CREDIT PERCEPTIONS AND THE FINANCIAL INTEGRITY OF**
10 **THE COMPANY.**

11 **A. As Mr. Fetter discusses, regulation is a key factor in assessing the future credit risk**
12 **profile of a utility because, among other things, a state public utility commission**
13 **determines the nature, amount, and timing of recovery of a utility’s cost of service**
14 **to its customers. Accordingly, the constructive practices and policies of regulatory**
15 **commissions play a critical role in the overall credit risk profiles of regulated**
16 **utilities and, ultimately, investors’ decisions. As such, it is imperative that state**
17 **utility commissions understand the financial, economic, and operational elements**
18 **of an evolving industry, and engage in a fair decision-making process that**
19 **demonstrates predictability and consistency. As Mr. Fetter has testified, these**
20 **qualitative factors can represent as much as half of the Company’s overall credit**
21 **rating.**

22 **For these reasons, rating agencies look for consistent application of sound**
23 **economic regulatory principles by utility regulators. If a regulatory body allowed a**
24 **utility the opportunity to earn a fair return on utility assets and subsequently applied**
25 **cost recovery principles in a manner inconsistent with the regulatory compact,**
26 **investors’ interest in providing funds to that utility would be altered, the utility’s**

1 risk profile would deteriorate, and the utility’s access to capital at reasonable terms
2 would suffer – all to the detriment of customers.

3 **Q. HOW IS THE COMMISSION CURRENTLY VIEWED BY THE**
4 **FINANCIAL COMMUNITY?**

5 A. S&P Global Market Intelligence (formerly Regulatory Research Associates or
6 “RRA”), a respected commentator on U.S. regulatory policy, rates the Georgia
7 regulatory environment (which goes beyond the Commission to also include state
8 legislative and executive branch policies) as Above Average 2. This places Georgia
9 among the top five of the 53 regulatory jurisdictions that S&P Global Market
10 Intelligence currently evaluates. The beneficial aspect, for both Georgia Power
11 investors and customers, of this ranking is its positive reflection in the credit rating
12 process, which provides the rating agencies with a degree of confidence that the
13 outcome in this rate case will be supportive of the Company’s financial integrity.
14 As the rating agencies have stated:

- 15 • **S&P:** In a November 18, 2021 report, S&P stated that Georgia
16 Power’s multiyear rate plan effective since the 2019 rate case
17 has been “supportive of GPC’s credit quality.”¹
- 18 • **Moody’s:** In an October 26, 2022 report, Moody’s stated, “The
19 stable outlook also considers our expectation that the overall
20 regulatory framework in Georgia will remain credit supportive
21 including a constructive outcome on the utility’s pending rate
22 case this December;”²
- 23 • **Fitch:** As stated in an October 4, 2022 report, “Fitch expects a
24 constructive resolution to Georgia Power’s pending rate case
25 filing, which proposes a three-year rate plan with rate increases

¹ S&P Research “Georgia Power Company,” November 18, 2021.

² Moody’s Credit Opinion, October 26, 2022.

1 of \$852 million, \$107 million, and \$45 million effective Jan. 1
2 of 2023, 2024, and 2025, respectively.”³

3 **Q. HOW DO CUSTOMERS BENEFIT WHEN THE COMPANY BALANCES**
4 **THE INTERESTS OF ALL STAKEHOLDERS?**

5 A. Customers benefit when the Company balances the interests of all stakeholders
6 because a financially healthy utility can meet the needs of its customers and is more
7 likely to achieve high levels of reliability and customer satisfaction. Customers also
8 benefit from the Company’s operating efficiencies in its efforts to meet investor
9 expectations. The efficiencies gained and the corresponding cost reductions that
10 result from those efforts are provided to customers through savings in rates.

11 **Q. WHAT ELEMENTS OF PIA STAFF’S RECOMMENDATIONS WOULD**
12 **THREATEN THE COMPANY’S FINANCIAL INTEGRITY?**

13 A. Virtually all of PIA Staff’s recommendations would severely harm the Company’s
14 financial integrity. Taken individually, Mr. Gorman’s recommended 9.45% ROE
15 set point and capital structure of 51% equity, beginning in year 2024, would
16 critically threaten the Company’s financial health. The cumulative negative impact
17 of Mr. Gorman’s recommendations coupled with those of Messrs. Smith and
18 Trokey would be even more dramatic.

19 **Q. IS THERE A WAY TO EVALUATE THE IMPACTS ON FUNDS FROM**
20 **OPERATIONS (“FFO”) TO DEBT AS A RESULT OF PIA STAFF’S**
21 **AGGREGATE RECOMMENDATIONS?**

22 A. Yes, if one were to recalculate Georgia Power’s FFO to debt assuming Mr.
23 Gorman’s recommended ROE of 9.45% and an equity ratio of 51% in 2024-2025,
24 the results are extremely negative to the financial integrity of Georgia Power.

³ Fitch Affirms Southern Company’s and Subsidiary’s Ratings, October 4, 2022.

1 Further, incorporating the detrimental effects of Messrs. Smith and Trokey's
2 recommendations, the 2023-2025 average FFO to debt would deteriorate by
3 roughly 500 basis points. The resulting Georgia Power credit profile, assuming the
4 collective recommendations by PIA Staff, would place the Company's financial
5 integrity at or below the lowest acceptable level recommended by Mr. Fetter. PIA
6 Staff's unreasonable recommendations would harm the Company's credit profile,
7 disturb the constructive regulatory environment that has benefitted Georgia
8 Power's customers, and harm customers by restricting the Company's access to
9 debt capital at reasonable terms and costs.

10 **Q. WHAT ARE THE CREDIT RATING AGENCIES' CURRENT**
11 **EXPECTATIONS REGARDING THE COMPANY'S FINANCIAL**
12 **INTEGRITY?**

13 A. Based on the latest Moody's Credit Opinion issued October 26, 2022, Moody's
14 states:

15 Georgia Power operates within a credit supportive Georgia
16 regulatory framework which generally provides timely recovery of
17 prudent costs and investments and allows for the company to
18 maintain a typically stable financial profile.

19 Moody's goes on to state:

20

21 Georgia Power is currently in a pending rate case and will look to
22 address the deferred fuel costs in a filing next February. Depending
23 on resolution of these regulatory filings, we expect Georgia Power's
24 financial profile to improve including a ratio of CFO pre-W/C to
25 debt of about 20% in 2023. Once the new nuclear units are in service
26 and depending on the ultimate investment recovery allowed by
27 regulators as result of the cost prudence review, the majority of
28 which will be completed when Unit 4 is in service, we expect a

1 substantial increase in Georgia Power's cash flow which should
2 translate into considerable improvement in credit metrics.

3 The punitive adjustments that Mr. Gorman and Messrs. Smith and Trokey
4 recommend would limit the FFO to debt metric to approximately 20% for the
5 foreseeable future. However, the rating agencies discuss in their publications the
6 expectation that, beginning in 2024, Georgia Power will remedy its credit profile
7 such that it assumes a position of bolstered strength and adequate credit quality.

8 **Q. WOULD PIA STAFF'S PROPOSED ADJUSTMENTS IMPAIR THE**
9 **COMPANY'S ABILITY TO IMPROVE ITS CREDIT METRICS OVER**
10 **TIME?**

11 A. Yes.

12 **Q. WILL MR. GORMAN'S PROPOSED ADJUSTMENTS PRODUCE THE**
13 **NECESSARY CASH FLOW TO YIELD AN APPROPRIATE CREDIT**
14 **RATING GOING FORWARD?**

15 A. No. The Company has identified an omission in Mr. Gorman's calculation of
16 expected FFO to debt. Mr. Gorman does not include the correct debt imputations
17 for purposes of the FFO to debt ratio that S&P prescribes in its most recent guidance
18 related to the application of S&P Global Ratings' "Corporate Methodology: Ratios
19 And Adjustments" criteria published April 1, 2019. By excluding more than \$5
20 billion of debt imputations, Mr. Gorman's credit metric expectation is significantly
21 overstated and fails to illustrate the harmful effects of his recommended ROE and
22 equity ratio.

23 **Q. WHAT WAS THE OMISSION IN MR. GORMAN'S FFO TO DEBT**
24 **CREDIT METRIC CALCULATION?**

25 A. In his recalculation of one of S&P's most important credit metrics, FFO to debt,
26 Mr. Gorman omitted the important debt imputation methodology S&P has directed

1 in previously issued authoritative publications. These debt imputations are essential
2 adjustments that must be made to arrive at a properly recalculated S&P credit
3 metric.

4 **Q. WHAT ARE DEBT IMPUTATIONS AND WHY DO RATING AGENCIES**
5 **REQUIRE THEM FOR PURPOSES OF CALCULATING THE CREDIT**
6 **METRIC “FFO TO DEBT”?**

7 A. Debt imputation is the act of adding debt-like fixed obligations to a utility’s
8 “traditional” debt balance when calculating FFO to debt. For many years, S&P has
9 viewed certain components on the balance sheet, including pension obligations,
10 lease liabilities, and asset retirement obligations as similar to debt and therefore
11 adds them to the debt balance when calculating credit metrics.

12 **Q. HOW DOES S&P OBTAIN THE INFORMATION TO PERFORM SUCH**
13 **CALCULATIONS?**

14 A. S&P uses the information included on the Company’s publicly available balance
15 sheet and accompanying financial disclosures to obtain pertinent information for
16 the proper debt imputation calculation. Georgia Power has no off-balance sheet
17 debt, or any other off-balance sheet components, that the rating agencies use when
18 calculating adjusted debt.

19 **Q. DID MR. GORMAN INCLUDE THIS DEBT IMPUTATION IN HIS FFO TO**
20 **DEBT CREDIT METRIC CALCULATION?**

21 A. No. In his recalculation of S&P’s credit metric, FFO to debt, Mr. Gorman omitted
22 the debt imputation methodology directed by S&P in previously issued
23 authoritative publications. These debt imputations are essential adjustments that
24 must be made to recalculate S&P’s credit metric.

1 In response to the question posed by PIA Staff and Mr. Gorman in data request
2 STF-BAI-1-17, the Company responded as follows:

3 **Question:**

4 Please state whether GPC's regulated retail operations have any
5 off-balance sheet debt such as purchased power agreements and
6 operating leases. If the answer is "yes," provide the amount of each
7 off-balance sheet debt item and estimate the related imputed interest
8 and amortization expense associated with these off-balance sheet
9 debt equivalents specific to GPC's jurisdictional regulated retail
10 electric operations.

11 **Response:**

12 No. Georgia Power does not have any off-balance sheet debt. In
13 2019, Georgia Power adopted the provisions of Financial
14 Accounting Standards Board (FASB) Accounting Standards
15 Codification ("ASC") Topic 842 (as amended), Leases (ASC 842),
16 which requires lessees to recognize leases with a term of greater than
17 12 months on the balance sheet as lease obligations. With the
18 adoption of the standard, the operating leases historically
19 representing off-balance sheet financing arrangements are now
20 reflected on Georgia Power's balance sheet.

21 In responding to this question, the Company correctly answered that it does not
22 have any off-balance sheet debt. The Company also clarified that obligations such
23 as purchased power agreements and operating leases are now found on the
24 Company's balance sheet. Mr. Gorman and the Company agree that these debt-like
25 obligations are the type of debt imputations that are appropriate to include in
26 estimating S&P's FFO to debt calculation. However, due to the confusion around
27 where these debt-like components are identified, these components were omitted
28 from Mr. Gorman's calculations. Mr. Gorman should have included the debt
29 imputations related to these on-balance sheet debt-like components in his estimated
30 recalculation of S&P credit metrics, as he did in the 2019 rate case.

1 **Q. WHAT AMOUNT OF DEBT IMPUTATION SHOULD HAVE BEEN**
2 **INCLUDED IN MR. GORMAN’S CALCULATIONS?**

3 A. Based upon the relevant balance sheet accounts, similar to those assessed in S&P’s
4 November 18, 2021, Ratings Direct report on Georgia Power,⁴ over \$5.5 billion of
5 debt imputations should have been adjusted for purposes of Mr. Gorman’s
6 estimated recalculation of S&P credit metrics. Had Mr. Gorman’s recalculation
7 included the proper S&P debt imputations, it would have shown that the Company’s
8 metrics, assuming Staff’s adjustments were accepted by the Commission, are
9 insufficient to maintain sufficient access to capital at reasonable rates.

10 **Q. DOES THE COMPANY AGREE WITH MR. GORMAN’S CONCLUSION**
11 **THAT ITS EQUITY RATIO SHOULD BE REDUCED TO 51%**
12 **BEGINNING IN 2024?**

13 A. No. Although Mr. Gorman acknowledges that the Company’s authorized equity
14 ratio was previously increased due to the negative effects of the 2017 Tax Cuts and
15 Jobs Act (“TCJA”), he completely ignores that these negative effects continue
16 today. Instead, he proposes that the Company’s equity ratio should be reduced to
17 51% once Vogtle Unit 4 is placed in service, wrongly assuming that the
18 construction of Vogtle Units 3 and 4 , and not the TCJA, was the catalyst to increase
19 the Company’s equity ratio to 56% and should, therefore, be the impetus to reduce
20 it back to 51%.

21 **Q. HOW WAS GEORGIA POWER’S CURRENT 56% EQUITY RATIO**
22 **DETERMINED IN THE COMPANY’S PRIOR 2019 RATE CASE?**

23 A. The Settlement Agreement approved in the 2019 Rate Case left it to the
24 Commission to determine the Company’s appropriate capital structure. Based on
25 the evidence presented in that case, the Commission found the appropriate capital

⁴ STF-NEC-1-1 Attachment AI.

1 structure to be 56% equity and 44% debt. As noted in the Commission’s Short
2 Order Adopting Settlement as Modified in the Company’s 2019 Rate Case in
3 Docket No. 42516, the Company’s equity ratio was adjusted from 51% to 55% as
4 a part of the TCJA Settlement in Docket No. 36989 (“Tax Reform Settlement”) to
5 address the negative implications of tax reform and provide support for maintaining
6 the Company’s credit profile. The Commission further determined that the
7 “proposed capital structure of 56% common equity level is just and reasonable
8 considering all of the evidence presented.”

9 **Q. HAVE THERE BEEN ANY CHANGES TO THE TCJA OR ITS NEGATIVE**
10 **IMPACTS ON THE COMPANY SINCE THE COMMISSION DEEMED**
11 **THE APPROPRIATE CAPITAL STRUCTURE FOR THE COMPANY TO**
12 **BE 56% EQUITY AND 44% DEBT?**

13 A. No.

14 **Q. DOES THE COMPANY ANTICIPATE ANY CHANGES TO THE TCJA OR**
15 **ITS NEGATIVE IMPLICATIONS ON THE COMPANY DURING 2023-**
16 **2025 THAT WOULD JUSTIFY LOWERING ITS EQUITY RATIO?**

17 A. No.

18 **Q. DOES ANY OTHER WITNESS RECOMMEND A SPECIFIC REDUCTION**
19 **IN THE EQUITY LEVEL IN THE COMPANY’S CAPITAL STRUCTURE?**

20 A. Yes. Georgia Association of Manufacturers (“GAM”) Witness LaConte
21 recommends that the Company’s equity ratio should be more in line with the
22 average equity ratio for the companies included in Witness Coyne’s proxy group
23 that have similar credit ratings as Georgia Power or should not exceed 53%. Ms.
24 LaConte’s proposal of 53% equity is not based on a careful and accurate analysis
25 of the credit rating implications of her recommendation. If a 53% equity level were
26 adopted by the Commission, that decrease would cause over 200 basis points of

1 deterioration in FFO to debt, harming the Company's financial integrity.
2 Additionally, as mentioned earlier, the 56% equity level set in the 2019 rate case
3 appropriately mitigates the negative credit impacts of the TCJA. The impacts of the
4 TCJA still exist; therefore, the Company must maintain its 56% equity ratio as
5 carefully reviewed and approved by the Commission in its 2019 rate case.

6 **Q. DOES THE COMPANY AGREE WITH MR. GORMAN'S**
7 **RECOMMENDATION TO REDUCE THE COMPANY'S ROE SET POINT**
8 **105 BASIS POINTS TO 9.45%, MRS. LACONTE'S RECOMMENDATION**
9 **TO REDUCE THE COMPANY'S ROE SET POINT 67 BASIS POINTS TO**
10 **9.83%, OR MS. RENO'S RECOMMENDATION TO REDUCE THE**
11 **COMPANY'S ROE SET POINT 103 BASIS POINTS TO 9.47%?**

12 A. No. Mr. Coyne will address the errors in Mr. Gorman's and Ms. Reno's calculations
13 in this regard. Notwithstanding these errors, their recommendations do not
14 represent current market conditions and would not result in full recovery of the
15 Company's cost of equity. Further, there is no justification for such severe
16 reductions in the Company's cost of equity since the last base rate case. For these
17 reasons, Mr. Gorman and Ms. Reno's recommendations are not supported and are
18 punitive when considering Georgia Power's record of strong performance. The
19 ROE reductions proposed by Mr. Gorman and Ms. Reno are a dramatic departure
20 from the approach employed by this Commission over the past several rate cases
21 and would surely be viewed negatively by the capital markets, as Mr. Fetter has
22 stated in his testimony. A reduction of this magnitude would be an unprecedented
23 change from the consistent and historically constructive regulation for which this
24 Commission has a reputation – one where excellence is recognized and rewarded,
25 not punished.

1 **III. MODIFICATIONS TO TRADITIONAL ALTERNATE RATE PLAN**

2 **Q. ARE PIA STAFF’S PROPOSED CHANGES TO THE COMPANY’S ARP**
3 **CONSISTENT WITH THE CONSTRUCTIVE REGULATORY**
4 **ENVIRONMENT TYPICAL OF PRIOR ARPS APPROVED BY THIS**
5 **COMMISSION?**

6 A. No. PIA Staff’s collective recommendations radically depart from the previously
7 accepted ARP structure and have the effect of removing the benefits to customers
8 resulting from the Company agreeing to enter an ARP in the first place. Three-year
9 ARPs avoid the potential for more frequent base rate cases, provide rate stability
10 and predictability to customers, provide for customer revenue sharing for earnings
11 above the approved earnings band, encourage the Company to operate efficiently,
12 and signal the type of regulatory consistency viewed favorably by credit rating
13 agencies.

14 **Q. IN WHAT WAY DOES THE COMPANY ASSUME RISK DURING THE**
15 **THREE-YEAR ACCOUNTING PERIOD?**

16 A. Because the Company surrenders its right to file a full rate case during the three-
17 year term when the ROE is within the authorized earnings band, the Company
18 assumes the risks of changing conditions during the term of the ARP. For example,
19 the level of inflation may increase more than projected, the cost of debt or equity
20 might increase, sales may be less than forecasted, or the Company’s overall cost of
21 service may be more than forecasted. A three-year rate plan holds the Company
22 accountable for inefficiencies or cost overruns due to rates being set at a
23 predetermined level for the duration of the three-year period.

1 **Q. DOES THE COMPANY AGREE WITH PIA STAFF'S**
2 **RECOMMENDATION TO USE THE TEST PERIOD REVENUE**
3 **REQUIREMENT FOR PURPOSES OF ESTABLISHING THE FIRST**
4 **YEAR REVENUE REQUIREMENT OF AN ARP?**

5 A. No. The revenue deficiency calculated for the calendar year ending December 31,
6 2023, rather than the deficiency for the split test year, reflects a more accurate
7 depiction of the costs the Company will incur in its first year under a new ARP
8 when the new rates are effective. Determining the revenue deficiency using the
9 calendar year reduces regulatory lag. In the Company's Errata Filing, the projected
10 revenue deficiency based on the traditional test period and the 2023 calendar year
11 is \$459.8 million and \$612.3 million, respectively, resulting in a difference of
12 \$152.5 million. This difference illustrates that basing the year one rate increase on
13 the split test period's revenue deficiency would create a revenue shortfall of \$152.5
14 million in the very first year of the three-year period. Therefore, setting rates based
15 on the test period would not permit the Company to timely recover its prudently
16 incurred costs in serving customers.

17 **Q. DOES THE COMPANY AGREE WITH PIA STAFF'S**
18 **RECOMMENDATION TO DEFER AND USE ANY REVENUE**
19 **SUFFICIENCY BASED ON PIA STAFF'S CALCULATED TEST YEAR**
20 **AND 2023 REVENUE REQUIREMENT FOR ACCELERATED**
21 **RECOGNITION OF DEFERRED COSTS?**

22 A. No. Based on the Company's proposal, the Company does not have a projected
23 revenue sufficiency in 2023 to apply to the deferred costs. As stated previously, the
24 Company's revenue deficiency should be based on the calendar year 2023 revenue
25 requirement rather than the test period, if the Company's ARP is adopted. However,
26 the Company generally agrees with PIA Staff's concept of applying revenue
27 sufficiency in a rate case, in the event there is any, to certain regulatory assets to
28 maintain rate stability for the customers.

1 **Q. WHY IS A LEVELIZED APPROACH MORE APPROPRIATE THAN THE**
2 **STEP INCREASE APPROACH RECOMMENDED BY PIA STAFF?**

3 A. The levelized approach results in \$43 million less being billed to customers than a
4 step increase approach over the three-year ARP. It also balances the needs of both
5 customers and the Company, allowing customers to benefit from three years of
6 stable and predictable rates while allowing the Company to recover its projected
7 revenue deficiency. Rate stability provides customers with a beneficial tool when
8 budgeting for their utility costs and provides a predictable revenue stream for the
9 Company.

10 The step increase approach would increase customer rates by an increasing amount
11 during each of the next three years. Although an annual increase would result in a
12 lower than requested projected revenue requirement for 2023 and 2024, the increase
13 for 2025 would be greater than the levelized amount, and rates would increase more
14 overall during the ARP. In addition, the fluctuation in projected costs year-to-year
15 creates uncertainty for customers. Although the Company shares PIA Staff's
16 interest in rate stability, the Company maintains that levelizing the proposed
17 increases over the three-year ARP is the more appropriate approach for customers.

18 **Q. ARE CUSTOMERS FAIRLY COMPENSATED FOR THE PROJECTED**
19 **OVER-COLLECTION IN THE FIRST TWO YEARS OF THE**
20 **LEVELIZATION?**

21 A. Yes. Based on the Company's projections under the levelized revenue requirement,
22 the Company would over-collect in 2023 and 2024 and under-collect in 2025. For
23 the projected advancement of revenues in 2023 and 2024, the Company proposes
24 to defer the amount as a regulatory liability, reducing retail rate base and giving
25 customers credit on the advanced amount based on the Company's full weighted
26 average cost of capital ("WACC"). This proposed deferral reduces the levelized

1 revenue requirement requested by the Company and fully amortizes the
2 advancement by the end of 2025.

3 **Q. DO YOU AGREE WITH PIA STAFF’S RECOMMENDATION THAT 100%**
4 **OF EARNINGS ABOVE THE TOP END OF THE EARNINGS BAND**
5 **SHOULD BE USED TO ACCELERATE DEFERRED COSTS?**

6 A. No. PIA Staff’s proposal amounts to an earnings cap by eliminating any retained
7 revenues earned above the earnings band. This removes any incentive for the
8 Company to exceed the top end of the band and pr does not encourage the Company
9 to maximize efficiencies during the ARP period. In addition, the top end of the
10 earnings band proposed by PIA Staff is set artificially low, at a level below even
11 the Company’s cost of equity.

12 **Q. HAS THE EARNINGS SHARING MECHANISM WORKED WELL FOR**
13 **THE COMPANY AND ITS CUSTOMERS?**

14 A. Yes. As presented in the table on page 130 of the testimony of PIA Staff Witnesses
15 Smith and Trokey, and as stated in our direct testimony, the Company returned
16 approximately \$297 million in benefits to customers as a result of the sharing
17 arrangements approved by the Commission in the 2013 and 2019 base rate cases.
18 As the table illustrates, this represents an average of approximately 78% of the
19 earnings above the top of the band being applied to the benefit of customers and
20 22% of the earnings being retained by the Company since 2014. These benefits
21 have been achieved without compromising superior customer satisfaction or
22 reliability. Notably, the amount customers pay through rates does not increase or
23 decrease when the Company’s earnings are within the band, because rates are set
24 on the ROE set point. As previously mentioned, the sharing mechanism is a critical
25 component of the ARP and appropriately encourages the Company to look for
26 efficiencies and process improvements, which can lead to higher earnings that
27 benefit both customers and the Company.

1 **Q. DOES THE COMPANY AGREE WITH COMMERCIAL GROUP**
2 **WITNESS CHRISS' RECOMMENDATION TO ADJUST THE EARNINGS**
3 **BAND COMMENSURATE WITH ANY ADJUSTMENT TO THE**
4 **REQUESTED 11% RETURN ON EQUITY SET POINT?**

5 A. No. If the Commission were to authorize a set point ROE less than the Company's
6 requested 11%, the bottom end of the earnings band should remain set at 9.5% with
7 the top end of the earnings band set at 12.0%.

8 **Q. DO YOU AGREE WITH DOD WITNESS BLANK'S PROPOSAL TO**
9 **NARROW THE ROE EARNINGS BAND AND REDUCE THE AMOUNT**
10 **OF EARNINGS ABOVE THE BAND RETAINED BY THE COMPANY?**

11 A. No. It appears that Mr. Blank is only recommending an ROE earnings band of 100
12 basis points above the ROE if the Commission authorizes an ROE below the
13 Company's requested 11%. This would result in the top of the earnings band being
14 lower than the 12% proposed by the Company. Otherwise, Mr. Blank reiterates his
15 recommendation from the 2019 rate case that the earnings band be narrowed to +/-
16 50 basis points above and below the target ROE. Narrowing the earnings band may
17 increase risks and uncertainty to customers. Second, Mr. Blank also recommends
18 reducing the Company's portion of any shared earnings above the top of the band,
19 which is not acceptable because it caps the Company's earnings incentive.

20 **IV. CCR AROS**

21 **Q. IS THE APPROVAL OF THE COMPANY'S CCR COMPLIANCE PLAN**
22 **AT ISSUE IN THIS PROCEEDING?**

23 A. No. The Commission-approved 2022 IRP Stipulation in Docket No. 44160
24 approved the Company's ECS and plan to comply with federal and state CCR
25 regulations, but reserved CCR cost recovery for determination in this rate case. This

1 includes the method of recovery and the appropriate period over which the
2 Company should recover costs.

3 **Q. DO ANY PARTIES DISAGREE WITH THE COMPANY'S PROPOSAL TO**
4 **CONTINUE THE CURRENT RECOVERY METHODOLOGY**
5 **REGARDING CCR ARO COMPLIANCE COSTS APPROVED IN THE**
6 **COMPANY'S 2019 RATE CASE?**

7 A. All parties generally agree with the current CCR ARO cost recovery methodology
8 except for GAM Witness Pollock, who proposes that the Company should not earn
9 an equity return on the CCR ARO regulatory asset balance. The Company's CCR
10 ARO compliance costs are required to comply with federal and state environmental
11 regulations and are appropriately included in rate base. As such, the Company
12 should be able to timely recover its prudently incurred costs and have the
13 opportunity to recover all of its financing costs, including equity. Witness Pollock's
14 recommendation prevents the Company's ability to recover its actual costs of
15 financing these required investments. In addition, his proposed ratemaking
16 treatment contradicts past treatment of ARO compliance costs and such departure
17 from past precedent is unjustified.

18 **Q. DOES THE COMPANY AGREE WITH MR. POLLOCK'S ASSERTION**
19 **THAT IT SHOULD NOT EARN A RETURN ON EQUITY ON**
20 **UNRECOVERED CCR COSTS UNTIL SECURITIZATION IS**
21 **AUTHORIZED?**

22 A. No. Denying the Company the opportunity to recover all of its financing costs on
23 any unrecovered CCR ARO compliance costs amounts to a disallowance and
24 inappropriately and prematurely assumes that such costs were not prudently
25 incurred. As Witness Pollock admitted upon cross examination, securitization is
26 not currently an option in Georgia and would require a change in state law to
27 implement. It would be inappropriate to deny the Company recovery of currently

1 incurred financing costs based solely on the potential for future securitization
2 legislation, over which neither the Company nor the Commission have control, and
3 which might never happen. Securitization is not needed as this Commission already
4 has all the tools necessary to appropriately balance the needs of our customers and
5 the Company.

6 **V. ELECTRIC TRANSPORTATION**

7 **Q. WHAT IS GEORGIA POWER’S ROLE IN SUPPORTING THE**
8 **DEVELOPMENT OF GEORGIA’S ELECTRIC TRANSPORTATION**
9 **(“ET”) ECOSYSTEM?**

10 A. Georgia Power must be prepared to meet the energy needs of all customers within
11 its service territory. Therefore, we continue to make appropriate investments in the
12 infrastructure and technology needed to support the growth of electric
13 transportation in Georgia that is being driven by customer interest and market
14 demand. These investments include the buildout and upgrade of infrastructure from
15 grid to charger that will enable charging across the state in public, at work, and at
16 home. In limited circumstances, Georgia Power will continue to offer EV charging
17 services as a provider of last resort in underserved areas through the Community
18 Charging Program. As such, Georgia Power will continue to support our state’s
19 developing ET ecosystem, which continues to experience economic growth as
20 evidenced by two major EV manufacturing announcements this year.

21 **Q. WHAT IS THE MAKE READY PROGRAM?**

22 A. Georgia Power’s Make Ready program helps to remove the biggest financial hurdle
23 of installing electric chargers at a qualifying customer’s location by installing,
24 owning, and maintaining the electrical infrastructure behind the meter up to the
25 charger, which typically includes the panel, switchgear, wiring, conduits, and

1 disconnects. The customer is then responsible for the procurement, installation,
2 maintenance, and energy to serve the EV charging equipment.

3 **Q. WHAT IS GEORGIA POWER’S REQUEST REGARDING THE MAKE**
4 **READY PROGRAM IN THIS CASE?**

5 A. The Company has requested to invest \$27 million per year for each year of the ARP
6 (2023-2025) for infrastructure upgrades in the Make Ready program. As stated in
7 the Company’s response to STF-LA-6-19, these capital expenditures include wires,
8 panels, conduit, transformers, and labor.

9 **Q. PLEASE DESCRIBE GEORGIA POWER’S COMMUNITY CHARGING**
10 **PROGRAM.**

11 A. Georgia Power’s Community Charging Program expands the growth of electric
12 vehicle direct current (“DC”) fast charging locations by partnering with businesses
13 to host an EV fast charging site where the charging will be made available to the
14 public. Georgia Power installs, operates, and maintains the chargers in this
15 program, which is designed to partner with customers to help grow critical public
16 EV infrastructure across Georgia. The Company primarily operates this program as
17 a provider of last resort to provide public DC fast charging options for EV drivers
18 in areas that lack investment in public DC fast charging. In the 2019 Rate Case, the
19 Commission approved \$2 million per year (2020-2022) in spending for the
20 Community Charging program. The Company’s request in this case for \$3 million
21 per year for each year of the ARP (2023-2025) is intended to maintain the
22 development and deployment of the Community Charging program. The increase
23 in funding requested reflects inflation and the increased cost of labor and
24 equipment.

1 **Q. WILL CONTINUED INVESTMENT IN ET INFRASTRUCTURE AT THE**
2 **LEVELS GEORGIA POWER REQUESTS PROVIDE ECONOMIC**
3 **BENEFITS TO CUSTOMERS?**

4 A. Yes. The Company's Rate Impact Measure ("RIM") analysis of the Make Ready
5 program indicates these investments will put downward pressure on rates over the
6 life of the technology, which benefits all customers. The Community Charging
7 program enables greater adoption of these technologies by providing public
8 charging along travel corridors throughout the state, especially in rural and
9 underserved communities that have not received infrastructure investments from
10 the private sector.

11 **VI. O&M ADJUSTMENTS**

12 **Q. PLEASE SUMMARIZE MR. MUGRACE'S RECOMMENDED O&M**
13 **ADJUSTMENTS.**

14 A. Mr. Mugrace recommends reducing the Company's projected O&M expenses by
15 \$192 million, \$147 million, \$137 million, and \$169 million in the test year and
16 2023, 2024, and 2025 rate years, respectively. Mr. Mugrace recommends the
17 Company adjust its projected functional O&M expenses for certain FERC accounts
18 based upon prior historical levels of O&M expenses. Mr. Mugrace also
19 recommends removing certain expenses historically allowed by the Commission
20 from the retail cost of service, such as certain employee labor costs, employee
21 retention costs, Innovation Center costs, and miscellaneous general expenses.
22 Furthermore, Mr. Mugrace recommends the Company reduce its labor expenses
23 based on vacancy rate ratio.

1 **Q. WHY IS A SIMPLE AVERAGE OF HISTORICAL COSTS NOT ALWAYS**
2 **A GOOD DETERMINANT OF PROJECTED COSTS?**

3 A. The Company's O&M expenses are complex and driven by many factors such as
4 timing and scope of outages, scheduled maintenance cycles, repair work, medical
5 claims, labor market, and contractor rates. These conditions in the historical period
6 are not identical to the test period and the Company and its business units consider
7 all these factors in the development of their respective budgets for the upcoming
8 three-year period. In addition, the historical years used by Mr. Mugrace includes
9 years 2020 and 2021, which were greatly impacted by the COVID pandemic and
10 are not representative of a "normal" year that should be relied upon as reflective of
11 costs to be incurred in the forecasted periods.

12 **Q. PLEASE DESCRIBE THE COMPANY'S O&M BUDGET PROCESS?**

13 A. Annually, the Company utilizes input from all areas of the business to plan and
14 budget the resources needed in support of expected workload for the upcoming
15 five-year forecasted period. The Company considers planned outage schedules,
16 expected maintenance activities, asset and vegetation management programs,
17 customer service needs, technology, fleet, materials, staffing levels, contractor
18 rates, and expected inflation when developing the budget. Budget assumptions are
19 vetted and approved to ensure consistency across business units.

20 During this process, Georgia Power reviews expenses and adjusts budgeted
21 amounts based on known increases or decreases, accordingly. The Company does
22 not create its budget by simply applying an inflation factor to all the actual, or
23 historic year expenses. Based on the type of expenditure, inflation rates may be
24 applied to derive projected expenses.

1 **Q. DOES THE COMPANY’S O&M REMAIN STATIC OVER TIME?**

2 A. No. The Company has seen significant price increases in nearly all areas of its
3 business. For example, transformer prices have increased over 48% since 2020,
4 wire and cable costs increased 33%, pole line hardware is up 27%, and pole costs
5 have increased 26%. Despite cost increases, budgets may fluctuate over a given
6 period of time due to multiple factors, including unit outages, changes in workforce
7 needs for both Company labor and contract labor, Company benefit costs, and
8 Commission-approved items such as Storm Recovery and demand side
9 management (“DSM”). These are only a few of the items that make up the
10 Company’s O&M request. The Company is constantly focused on managing its
11 O&M expenditures, emphasizing cost containment as part of its corporate culture,
12 as reasonable and necessary cost containment is in the best interest of both the
13 Company and its customers. The Company has identified efficiencies in nearly
14 every part of its business while still providing superior customer satisfaction and
15 reliable service to customers.

16 **Q. AS AN EXAMPLE OF WHY SIMPLY ESCALATING HISTORIC COSTS**
17 **IS INAPPROPRIATE, WHAT IS DRIVING THE INCREASE IN O&M**
18 **EXPENSES IN CUSTOMER SERVICE AND INFORMATION FOR THE**
19 **TEST PERIOD AND YEARS 2023 THROUGH 2025?**

20 A. The primary driver for the increase in Customer Service and Information expenses
21 is related to the increase in DSM expenses as a result of the DSM programs
22 approved by the Commission in the 2022 DSM Certification in Docket No. 44161.
23 Because the projected level of DSM expenses are directly attributed to the DSM
24 programs approved by the Commission, historical costs are clearly not a good
25 indicator of the projected expenses for the ARP years reflected in the filing.

1 **Q. ARE WITNESS MUGRACE’S RECOMMENDATIONS REGARDING DSM**
2 **PROGRAM EXPENSES APPROPRIATE?**

3 A. No. In fact, PIA Staff’s panel of Barber, Deitchman, Watkins does not recommend
4 any adjustments to the DSM program expenses.

5 **Q. WHY IS IT INAPPROPRIATE TO REMOVE THE COSTS ASSOCIATED**
6 **WITH THE INNOVATION CENTER FROM RETAIL COST OF SERVICE**
7 **AS PROPOSED BY PIA STAFF?**

8 A. The Company’s Energy Innovation Center (“EIC”) is related to but distinct from
9 Research and Development in that the EIC is focused on education and exchanging
10 ideas and information with all customer segments and stakeholders. The EIC is a
11 platform where Georgia Power can share with customers general educational
12 materials on innovative technologies, discuss end-use applications that will be
13 beneficial for customers, bring stakeholders together, and establish a foundation for
14 future partnerships between the utility and customers. Establishing a forum to
15 circulate these ideas around technology innovation, and their market milestones, is
16 fundamentally beneficial to Georgia Power’s customers because it has led to project
17 activities that deliver cost saving efficiency and sustainability outcomes, with the
18 potential to deliver grid-level benefits that improve reliability. The EIC is a resource
19 for customers and stakeholders to learn about new energy technologies and how
20 they may participate in their deployment, where applicable and appropriate.

21 **Q. HAVE THE COSTS ASSOCIATED WITH THE ENERGY INNOVATION**
22 **CENTER PREVIOUSLY BEEN APPROVED BY THE COMMISSION IN**
23 **RETAIL COST OF SERVICE?**

24 A. Yes.

1 **Q. WHY IS IT INAPPROPRIATE TO REMOVE THE SERVICE AWARDS**
2 **AND RECREATION COSTS FROM RETAIL COST OF SERVICE?**

3 A. The service award program is a part of the overall compensation package offered
4 to all full-time and part-time active employees, which helps motivate and retain the
5 talent needed to efficiently operate the Company's business. It demonstrates
6 recognition and appreciation to employees for company service at specific service
7 intervals. As stated in STF-PCMG-2-12, the costs listed as recreation costs are
8 actually meals and travel expenses that were inadvertently budgeted to FERC
9 account 926 instead of FERC account 921. These are not a "new" set of costs as
10 the Company incurred similar expenses in prior periods, which were correctly
11 recorded to FERC account 921.

12 **Q. HAVE THE SERVICE AWARDS AND MEALS AND TRAVEL EXPENSES**
13 **PREVIOUSLY BEEN APPROVED BY THE COMMISSION IN RETAIL**
14 **COST OF SERVICE?**

15 A. Yes.

16 **Q. WHY IS IT INAPPROPRIATE TO REMOVE MISCELLANEOUS**
17 **GENERAL EXPENSES INCLUDING ASSOCIATION DUES,**
18 **COMMUNITY SERVICE, AND EXPERIMENTAL COSTS FROM RETAIL**
19 **COST OF SERVICE?**

20 A. Contrary to the assertion of PIA Staff Witness Mugrace, these items are necessary
21 costs incurred in operating the business and our customers benefit from these
22 activities. Through these efforts, the Company develops technology efficiencies
23 that reduce O&M expenses and equipment improvements that improve the
24 reliability of the grid. As a member of certain associations, the Company and its
25 employees learn, grow, and contribute to the sustainability of the electric industry.
26 Costs associated with community organizations, community development,

1 economic development and other business issues benefit the communities we serve.
2 Investments in these areas help the Company engage with customers and
3 communities, which allows for growth and sustainability across the state.

4 **Q. HAVE MISCELLANEOUS GENERAL EXPENSES INCLUDING**
5 **ASSOCIATION DUES, COMMUNITY SERVICE, AND EXPERIMENTAL**
6 **COSTS PREVIOUSLY BEEN APPROVED BY THE COMMISSION IN**
7 **RETAIL COST OF SERVICE?**

8 A. Yes.

9 **Q. PLEASE DESCRIBE HOW THE COMPANY CALCULATED THE**
10 **INCREMENTAL INFLATION ASSOCIATED WITH ITS O&M**
11 **EXPENSES?**

12 A. The Company began to see significant price increases across all aspects of its
13 business consistent with the rising inflation factors found in the Employment Cost
14 Index (“ECI”) and Gross Domestic Product (“GDP”) deflator. In response to these
15 signals, the Company adjusted its projected O&M expenses to account for these
16 cost increases in this filing by identifying labor and non-labor costs that typically
17 would fluctuate based on inflation factors and applying the incremental increase in
18 ECI and GDP inflation rates to the appropriate cost types. The adjustments were
19 recorded at a summary account level across several FERC accounts as provided in
20 STF-PCMG-1-5. Items such as benefits, incentive pay, insurance, and parity were
21 excluded from the adjustment.

22 **Q. WHY IS STAFF’S COMPARISON AND THE RESULTING**
23 **RECOMMENDED ADJUSTMENT OF INCREMENTAL INFLATION**
24 **INAPPROPRIATE?**

25 A. Although Mr. Mugrace states that the ECI is an appropriate source of inflation rates
26 for labor costs, he ultimately used only the lower GDP index to escalate total non-

1 Production O&M expenses, including labor and non-labor costs, to calculate his
2 incremental inflation adjustment. In order to appropriately calculate the adjustment,
3 the O&M expenses need to be separated into labor and non-labor charges and the
4 ECI and GDP rates need to be applied to the respective costs, as the Company did
5 in performing its calculation of the incremental inflation adjustment. In addition,
6 Mr. Mugrace did not carry forward the incremental inflation adjustment calculated
7 in Year 1 to the subsequent years, which caused the impact in future years to be
8 understated. Since the escalation indexes are increases from the prior year, any
9 incremental inflation adjustments from the prior year need to be accounted for in
10 the calculation of incremental inflation in a given year.

11 **Q. PLEASE DESCRIBE THE COMPANY'S BUDGETED HEADCOUNT IN**
12 **THE FORECASTED PERIODS?**

13 A. The Company budgeted its headcount and total labor costs, including internal and
14 contract labor as well as overtime, at the level needed to operate its business and,
15 therefore, there is no headcount vacancy reflected in the Company's forecast.

16 **Q. IF THE COMPANY IS UNABLE TO HIRE THE FULL NUMBER OF**
17 **EMPLOYEES BUDGETED TO PERFORM ITS OPERATIONS, HOW**
18 **DOES THE COMPANY CONTINUE TO MANAGE ITS BUSINESS?**

19 A. The Company fills open positions with overtime labor from the existing workforce
20 or hires additional contract labor to perform the necessary work if it is unable to
21 hire the full number of employees budgeted. In this example, while internal labor
22 costs decrease, overtime and contract labor increase to offset the reduction.

23 **Q. WHAT INCORRECT LABOR BUDGET ASSUMPTIONS OR ERRORS**
24 **WERE INCLUDED IN MR. MUGRACE'S TESTIMONY?**

25 A. Mr. Mugrace makes several errors based on flawed assumptions about how and
26 where labor dollars are budgeted. The labor dollars referenced by Mr. Mugrace

1 throughout his testimony only capture contract labor dollars and not internal labor
2 dollars. There are internal labor dollars included within the functional O&M
3 expenses from which Mr. Mugrace attempted to remove all labor dollars to
4 determine non-labor expenses. The results of Mr. Mugrace's adjustments are
5 significantly flawed because he failed to remove the internal labor dollars in his
6 analysis. Additionally, the costs associated with the Performance Pay Program
7 ("PPP") and payroll taxes are removed from contract labor although the Company
8 provides neither PPP nor payroll taxes for contract labor. In some instances, there
9 also appear to be inconsistencies where Mr. Mugrace only applied adjustments to
10 the test year, while for other years, the adjustments were only applied to years 2023
11 through 2025. For example, Mr. Mugrace recommends reducing the Company's
12 proposed incremental inflation expenses for years 2023 through 2025 but does not
13 recommend a corresponding adjustment to the test year, which shows an increase
14 in O&M expenses resulting from his analysis.

15 **Q. WHY IS IT INAPPROPRIATE TO REMOVE CERTAIN EMPLOYEE**
16 **LABOR COSTS FROM RETAIL COST OF SERVICE?**

17 A. To provide its award-winning service to customers, Georgia Power must attract and
18 retain a high level of skilled and professional employees, who are paid
19 competitively and appropriately based on their role. The Company's costs related
20 to Supplemental Executive Retirement Plan ("SERP") and non-SERP benefit costs
21 as well as employee retention are necessary expenses to ensure the attraction and
22 retention of our highly skilled workforce.

23 The SERP and non-SERP programs are used to attract and retain senior
24 management level employees across the various business units of the Company
25 who have key roles, experiences, and skills in managing employees to ensure
26 Georgia Power continues to provide reliable customer service and maintain our
27 standards of safety. These types of programs are common for other companies who
28 provide qualified pension plan benefits and are regularly evaluated to ensure that

1 the total compensation for our employees including these pension benefit programs
2 is market competitive. Furthermore, these non-qualified pension programs are not
3 funded and therefore, are not covered by corporate-owned life insurance benefits
4 as stated by Mr. Mugrace in his testimony.

5 Employee retention agreements are utilized as targeted, strategic compensation
6 tools to retain high-performing employees in critical roles throughout the Company
7 who offer deep experience, knowledge, and expertise. These agreements are
8 entered into in direct response to specifically identified market pressures. Such
9 pressures often include recruitment by Company competitors and peers, within and
10 outside of the Company's industry, as well as within and outside of the Company's
11 geographic footprint. Employee retention costs allow the Company to continue
12 providing excellent service for our customer base and further maintain the
13 resiliency of our infrastructure. Further, these costs offset the potential future
14 expenses that would be incurred to recruit, develop and train substitute employees
15 for these key roles.

16 **Q. HAVE THESE EMPLOYEE LABOR COSTS PREVIOUSLY BEEN**
17 **APPROVED BY THE COMMISSION IN RETAIL COST OF SERVICE?**

18 A. Yes.

19 **Q. WHAT IS THE GOAL OF GEORGIA POWER'S EMPLOYEE**
20 **COMPENSATION PROGRAM?**

21 A. To provide its award-winning service to customers, Georgia Power must attract and
22 retain highly skilled employees. Therefore, Georgia Power's employee
23 compensation program is designed to provide competitive compensation at levels
24 targeting the 50th percentile of the appropriate markets. The Company's well-
25 balanced and market competitive compensation program provides different types
26 of compensation that are commonly known and recognized by compensation

professionals to be market appropriate to retain and attract talent, which includes (i) fixed based compensation, (ii) variable short-term compensation, and (iii) long-term stock-based compensation. The goal of providing different types of compensation is to create a balanced incentive system to ensure that employees are providing the best service to customers at the least cost. Evaluating compensation as a whole allows Georgia Power to maximize the effective use of resources essential to efficiently serve its customers by linking a portion of the employees' compensation package to operational and financial performance, thus aligning the compensation programs with Georgia Power's need to attract, engage, retain, and motivate its highly skilled workforce.

Q. WHAT IS PIA STAFF'S CONCERN WITH THE COMPANY'S PROPOSED EMPLOYEE COMPENSATION PROGRAM?

A. According to the testimony of Messrs. Smith, Trokey, and Mugrace, it appears that PIA Staff believes certain portions of the Company's total compensation program – the long-term incentive stock-based compensation plan and the amounts of the PPP attributed to financial goals – do not benefit customers and should therefore be borne by shareholders instead of customers.

Q. DOES THE COMPANY AGREE WITH THE DISALLOWANCES FOR THE EMPLOYEE COMPENSATION PROGRAM PROPOSED BY PIA STAFF?

A. No. The Company's existing compensation policy is necessary to attract, motivate, and retain a highly skilled, dedicated workforce, and to provide customers with clean, safe, and reliable service while efficiently managing costs. If "at-risk" components of the employee compensation program which includes the long-term incentive stock-based compensation plan and the amounts of the PPP attributed to financial goals was eliminated or significantly reduced, the Company would have to commensurately increase other components of its total compensation package –

1 such as direct salary costs – to maintain its competitiveness as an employer within
2 the industry and to continue to attract a skilled workforce. It would result in higher
3 fixed costs and poor alignment of all stakeholders’ interests, including customers.

4 PIA Staff’s proposed disallowance of these portions of the employee compensation
5 program are not based upon any supporting data or market analysis that the
6 Company’s expenses are excessive or that the programs are not competitive with
7 the external market. There is also no basis for Mr. Mugrace’s assertion that, “[t]hese
8 types of incentive costs benefit the Shareholders of the Company, and of SCS and
9 SNC, and do not directly benefit the ratepayers in the area of safe and reliable utility
10 service.”

11 The budgeted costs to attract, retain, and engage employees are expenses that arise
12 in the ordinary course of the Company’s business and should be included in the
13 Company’s revenue requirements and recovered in retail rates.

14 Further, the payroll tax expenses associated with stock-based compensation are also
15 a prudently incurred cost of doing business and, therefore, should be recovered
16 from customers. However, Messrs. Smith and Trokey applied both the Federal
17 Insurance Contributions Act (“FICA”) and Medicare portions of payroll tax to the
18 stock-based compensation adjustment when calculating their payroll tax expense
19 adjustment to be excluded from retail cost of service. As they noted on schedule E-
20 5 in PIA Staff’s Exhibit_(RS-RT-2), it is likely that employees who are eligible for
21 the Company’s stock-based compensation programs would have annual salaries
22 above the projected FICA threshold. Therefore, it is appropriate to apply only the
23 Medicare portion of payroll tax to the stock-based compensation expense when
24 calculating the applicable payroll tax expense adjustment.

1 **Q. WHY DOES THE COMPANY PROVIDE LONG-TERM INCENTIVE**
2 **BASED COMPENSATION?**

3 A. The long-term incentive based at-risk compensation program incentivizes
4 employees to make decisions that are in the long-term best interest of customers
5 and the Company. Customers benefit from a financially healthy company, which
6 should be measured over the short- and long-term to ensure that the decisions made
7 by the Company are optimized for both short- and long-term benefits. This is
8 especially true in the utility industry, where decisions related to infrastructure and
9 other major capital projects may have long-lasting financial consequences to all
10 stakeholders including customers. Customers would be harmed if the Company
11 were to drive its employees to sacrifice long-term financial health for short-term
12 benefits. By designing the at-risk portion of the total compensation plan to include
13 longer-term goals, the Company achieves an appropriate incentive balance that
14 motivates employees to deliver safe, clean, and reliable electric service to our
15 customers in a manner that is economically efficient both now and in the years that
16 follow.

17 **Q. WHY IS IT IMPORTANT THAT AN INCENTIVE COMPENSATION**
18 **PLAN INCLUDE BOTH OPERATIONAL AND FINANCIAL GOALS?**

19 A. Georgia Power seeks to create a balanced incentive system to ensure that employees
20 are providing the best service to customers at the least cost. Evaluating
21 compensation as a whole allows Georgia Power to maximize the effective use of
22 resources essential to efficiently serving its customers by linking a portion of the
23 employees' compensation package to operational and financial performance and
24 allows for the alignment of the compensation programs with Georgia Power's need
25 to attract, engage, retain, and motivate its highly skilled workforce. A well-designed
26 total compensation program using sound compensation practices and principles
27 provides a balance between operational focus and financial focus for both the short
28 term and longer term to drive employee behavior in ways that balance the interests

1 of customers and shareholders alike. A compensation plan that contains only
2 operational goals might inappropriately drive employees to use more financial
3 resources than necessary to achieve operational success, while a plan that contains
4 only financial goals might inappropriately drive employees to make decisions that
5 adversely impact operational success. A balanced program of incentive
6 compensation is a powerful tool that drives employees to put the customer at the
7 center of all we do while sustaining the financial integrity of the Company.

8 **Q. HOW DO THE ELEMENTS OF GEORGIA POWER'S COMPENSATION**
9 **PROGRAM THAT ARE BASED ON FINANCIAL OBJECTIVES PROVIDE**
10 **BENEFITS TO CUSTOMERS?**

11 A. Goals based on financial metrics – when included in an incentive compensation
12 plan designed to balance financial and operational goals– provide benefits to
13 customers by reducing expenses, creating greater efficiencies in operations,
14 ensuring a financially strong company, and allowing access to the capital markets
15 at a low cost.

16 **Q. WHAT MIGHT GEORGIA POWER AND ITS CUSTOMERS**
17 **EXPERIENCE IF THE COMPANY IS UNABLE TO RECOVER THESE**
18 **COSTS?**

19 A. Disallowing recovery of a financial component for a level of standard market pay
20 forces a utility to consider modifying the entire incentive design to be based on
21 operational measures alone (which are recoverable) and eliminate financial
22 components of the incentive program design. However, making this change to an
23 operational-based incentive program design would not be in the best interests of
24 customers, as it would encourage employees to focus solely on operational
25 performance with no balance or accountability to cost (causing employees to
26 improve operational performance and customer satisfaction regardless of the
27 financial cost to do so). Georgia Power strongly believes this imbalance is not in

1 the best interests of customers, and also believes this will lead to higher rate
2 increases for customers in the future with little to no benefit or improvement to
3 operations.

4 **Q. DOES THE COMPANY AGREE WITH MESSRS. SMITH AND TROKEY'S**
5 **STATEMENT THAT "THE OBJECTIVES OF MAXIMIZING**
6 **SHAREHOLDER VALUE ON THE ONE HAND AND MINIMIZING**
7 **COSTS TO RATEPAYERS ON THE OTHER HAND, ARE GENERALLY**
8 **OPPOSED TO EACH OTHER"?**

9 A. No. To deliver value to shareholders, the Company must constantly find ways to
10 run its business as efficiently as possible without sacrificing customer satisfaction
11 and reliability. The efficiencies gained and the cost reductions resulting from those
12 efforts are returned to customers through lower revenue requirements. Therefore,
13 many of the Company's actions to increase shareholder value will result in lower
14 costs and increased value to customers.

15 **VII. OTHER ISSUES**

16 *Revenue Forecast*

17 **Q. DOES THE COMPANY AGREE WITH PIA STAFF'S RECOMMENDED**
18 **REDUCTION TO THE COMPANY'S PROJECTED REVENUE**
19 **FORECAST?**

20 A. No. While the Company appreciates that differences of opinion may exist in the
21 intricacies of forecast modeling, the Company believes the projected revenue
22 forecast included in its filing continues to be the most reasonable and appropriate
23 method to determine the Company's revenue requirement at present rates. In
24 addition, PIA Staff agreed that the Company's method was reasonable and did not
25 identify any errors or corrections in the Company's filing. PIA Staff simply offered
26 an alternative for Commission consideration.

1 **Q. WHAT IS THE COMPANY’S POSITION REGARDING PIA STAFF’S**
2 **RECOMMENDATIONS TO ESTABLISH A REQUIREMENT FOR**
3 **FILING DETAILED REVENUE FORECAST TESTIMONY AND**
4 **WORKPAPERS IN FUTURE RATE CASES?**

5 A. Should the Commission believe a modification to the Base Rate Case Minimum
6 Filing Requirements (“MFRs”) is warranted to address the revenue forecast, the
7 Company would support working with the Staff to make the necessary revisions.

8 *Compliance Filing Requirements*

9 **Q. DOES THE COMPANY AGREE WITH PIA STAFF’S RECOMMENDED**
10 **DATA REVISIONS TO THE CURRENT ANNUAL COMPLIANCE FILING**
11 **REQUIREMENTS?**

12 A. No. The data elements currently updated in the annual Compliance Filings
13 established in the Settlement Agreement approved in the Company’s 2019 Rate
14 Case provide benefits to customers and equity to all parties. The additional elements
15 that Staff proposes to incorporate into the annual Compliance Filings risk
16 transforming this established, efficient, and effective process into a burdensome,
17 mini rate case proceeding. More importantly, as the number of data elements to be
18 re-estimated and readdressed on an annual basis via the Compliance Filings
19 increases, the more the benefits and value of the three-year ARP are undermined.

20 *Depreciation*

21 **Q. PLEASE SUMMARIZE YOUR CONCERNS WITH PIA STAFF’S**
22 **WITNESS KAUFMAN’S DEPRECIATION RECOMENDATION.**

23 A. Although the Company agrees with Mr. Kaufman’s proposed depreciation life
24 extension of Plant Hatch, there are some important areas of disagreement with other
25 aspects of his testimony, as described below:

- 1 • Contingencies should not be removed from production dismantling costs.
- 2 • The lives for hydro, transmission, distribution, and general plant should not
- 3 be extended.
- 4 • Mr. Kaufman fails to update certain components of the calculations used for
- 5 extending the lives of certain generating units and Transmission,
- 6 Distribution, and General plant.

7 In addition, PIA Staff incorrectly applies Mr. Kaufman’s proposed depreciation
8 rates for Transmission, Distribution and General plant easements to the appropriate
9 plant in service balances.

10 **Q. CAN YOU BRIEFLY DESCRIBE THE CONCERNS YOU HAVE**
11 **REGARDING PIA STAFF’S DISMANTLEMENT COST ASSUMPTIONS?**

12 A. PIA Staff Witness Kaufman removes contingency from plant dismantlement cost
13 estimates for coal and gas production facilities. He concludes that contingency
14 represents “unexpected outcomes” and therefore, should be removed from the
15 depreciation expense calculations for the Company’s coal and gas plants.

16 When developing cost estimates, contingency is a fundamental element of a
17 comprehensive and transparent estimate. Contingency is necessary to acknowledge
18 and mitigate the risk of inherent cost uncertainties that accompany capital-intensive
19 projects such as dismantlement of a coal or gas fired electric generation facility.

20 **Q. ARE THERE FACTORS THAT THE COMPANY MUST CONSIDER FOR**
21 **CURRENT AND FUTURE PLANT DISMANTLEMENTS THAT HAVE**
22 **NOT AFFECTED HISTORIC PLANT DISMANTLEMENTS?**

23 A. Yes. Prior to the retirement of Plant Hammond in 2019, historic retired facilities
24 did not have air environmental controls (*e.g.*, baghouses, scrubbers, Selective

1 Catalytic Reduction Systems). These environmental controls significantly increase
2 the footprint and dismantlement cost of the remaining coal facilities.

3 **Q. HAVE HISTORIC DISMANTLEMENT COST ESTIMATES, INCLUDING**
4 **CONTINGENCY, PREVIOUSLY BEEN APPROVED BY THE**
5 **COMMISSION IN RETAIL COST OF SERVICE?**

6 A. Yes.

7 **VIII. GRID INVESTMENT PLAN, DERMS, AND RULES AND**
8 **REGULATIONS SECTION G**

9 *Transmission Grid Investment*

10 **Q. HAS THE COMPANY USED OBJECTIVE APPROACHES TO**
11 **DETERMINE WHICH EQUIPMENT SHOULD BE REPLACED AS PART**
12 **OF THE GRID INVESTMENT PLAN AS RECOMMENDED BY STAFF**
13 **WITNESSES ALVAREZ, STEPHENS, AND RANA?**

14 A. Yes, the Company relied on its long history of robust maintenance practices,
15 internal experience, and historical operational knowledge to determine which
16 transmission equipment will be replaced as part of the Grid Investment Plan. The
17 Company incorporated this experience into its recommendation to replace
18 transmission equipment that will be greater than the Company expected life by the
19 end of the Grid Investment Plan period. While the industry expected life for
20 transformers and breakers is 35 years and 25 years, respectively, the Company has
21 been able to extend the life of equipment beyond its industry expected life through
22 its existing comprehensive maintenance practices. The Company's expected life for
23 transformers and breakers is 50 years and 35 years, respectively.

24 Contrary to Staff Witnesses Alvarez, Stephens, and Rana's overreliance on
25 inspection and performance testing for determining when equipment should be
26 replaced, routine diagnostic testing and inspections cannot always accurately

1 predict when equipment failure will occur on the system. Over the last ten years,
2 196 substation transformers failed in-service at an average age of 43 years, which
3 is lower than the Company expected life for this asset. Of these 196 substation
4 transformers, 108 failed (55%) after passing such diagnostic tests and inspections.
5 Therefore, the Company's experience to date informed its recommendation to
6 replace transmission assets through the Grid Investment Program that have or will
7 exceed their Company expected life by 2031 rather than solely relying on the results
8 of the Company's routine diagnostic tests and inspections.

9 **Q. WILL TRANSMISSION INVESTMENTS IN THE GRID INVESTMENT**
10 **PLAN PREVENT SYSTEM RELIABILITY DETERIORATION?**

11 A. Yes. Transmission investments pursuant to the Company's Grid Investment Plan
12 are intended to replace assets that have or will have exceeded their Company
13 expected life by the end of the plan. These assets are being replaced to prevent
14 reliability challenges associated with aged transmission assets. Based on the
15 Company's operational experience and common understanding, the likelihood of
16 failure for transmission assets included in the plan increases as the assets age
17 beyond their expected life. Due to the large percentage of transmission equipment
18 that is beyond or nearing its Company expected life, the Company designed the
19 Grid Investment Plan to target the reasonable replacement of such assets to prevent
20 transmission system reliability deterioration across the system. If these
21 replacements are not undertaken, system reliability will be negatively impacted due
22 to increased failures of aged equipment. Such failures can be catastrophic and
23 simultaneous in nature. Replacing these aged assets will reduce the number of
24 emergency failures, mitigate system operation reliability concerns, avoid higher
25 maintenance and replacement costs, and ensure the safety of the general public and
26 the Company's employees.

1 **Q. WOULD IT BE PRACTICAL FOR THE COMPANY TO CONDUCT AND**
2 **RELY ON A COST-BENEFIT ANALYSIS FOR TRANSMISSION**
3 **INVESTMENTS INCLUDED IN THE GRID INVESTMENT PLAN AS**
4 **RECOMMENDED BY PIA STAFF WITNESSES?**

5 A. No, it is impractical to perform a cost-benefit analysis for transmission investments
6 included in the Grid Investment Plan due to the dynamic and networked nature of
7 the transmission system and the number of variables that could change suddenly in
8 such a study. The transmission system has a wide variety of components and factors
9 that impact its operation, such as system loading and flows, facility and generation
10 outages, and weather. The ability to conduct a meaningful and accurate cost-benefit
11 analysis of transmission investments in the Grid Investment Plan is further
12 complicated by the type of failure that could occur (controlled or catastrophic),
13 impacts to other capital projects, lead times for replacement equipment, and the cost
14 of generation redispatch due to loss of transmission elements. The constant change
15 in these variables would produce a cost-benefit analysis with unreliable conclusions
16 that could be rendered obsolete or invalid at any given time. The results of such an
17 analysis would be questionable, at best. For these reasons, the Company used asset
18 age to determine capital investment in each transmission facility to mitigate the risk
19 of outages associated with a significant and growing number of assets that are
20 approaching or have exceeded their Company expected lives.

21 **Q. DOES THE COMPANY'S DATA SUPPORT STAFF WITNESS**
22 **STEPHENS' ASSERTION THAT TRANSMISSION EQUIPMENT CAN**
23 **OPERATE SAFELY AND RELIABLY PAST EXPECTED LIFE FOR UP**
24 **TO 100 YEARS?**

25 A. No. Witness Stephens' example of a single 99-year-old transformer on Georgia
26 Power's system should not be used as a basis for the assumption that the Company's
27 entire transformer fleet can or should operate that far beyond Company expected
28 life. The tables below represent transmission and distribution substation equipment

1 within 10 years of the oldest vintages for transmission and distribution substation
2 equipment on Georgia Power's system. The vintages shown in Tables 2 and 3
3 represent a significantly small portion of each equipment category, with the highest
4 vintage percentage being only 2% of the entire population for that equipment type.
5 More importantly, power transformers are less than 0.2% for both substation types.

6 **TABLE 2: FERC Account 353 - Transmission Station Equipment**

Equipment Type	Oldest Vintage	Percentage of Total Population (within 10 years of oldest vintage)
Circuit Breakers	1945	2.08868%
Other	1930	0.00031%
Power Transformer	1923	0.16695%
Relay	1955	1.37020%
Voltage Regulator	1938	0.00000%

7 **TABLE 3: FERC Account 362 – Distribution Station Equipment**

Equipment Type	Oldest Vintage	Percentage of Total Population (within 10 years of oldest vintage)
Circuit Breakers	1946	1.72047%
Other	1926	0.00408%
Power Transformer	1926	0.11719%
Relay	1931	0.02160%
Voltage Regulator	1948	0.23549%

8 This data indicates that while a very small portion of substation equipment can
9 operate well past Company expected life, Georgia Power should not expect the
10 overwhelming majority of its transmission and distribution assets to operate safely
11 and reliably for this long. As mentioned previously, the Company's data over the
12 last ten years shows that substation transformers have failed at an average age of
13 43 years, which is well below the timeframe that Mr. Stephens suggests that
14 equipment can remain in operation. Furthermore, the average age of failure for
15 transformers over the last ten years (43 years) is past industry expected life (35
16 years), but earlier than the age (50 years) at which this equipment will be replaced
17 within the Grid Investment Plan. Given the large number of transmission assets that
18 will exceed their Company expected life in the near future, replacement within the

1 Grid Investment Plan, as designed, is a better solution for the transmission system
2 than simply operating these assets for an unknown period of time until they fail. If
3 the Company does not continue with these investments, the risk of catastrophic
4 equipment failure along with facility and customer outages will increase.

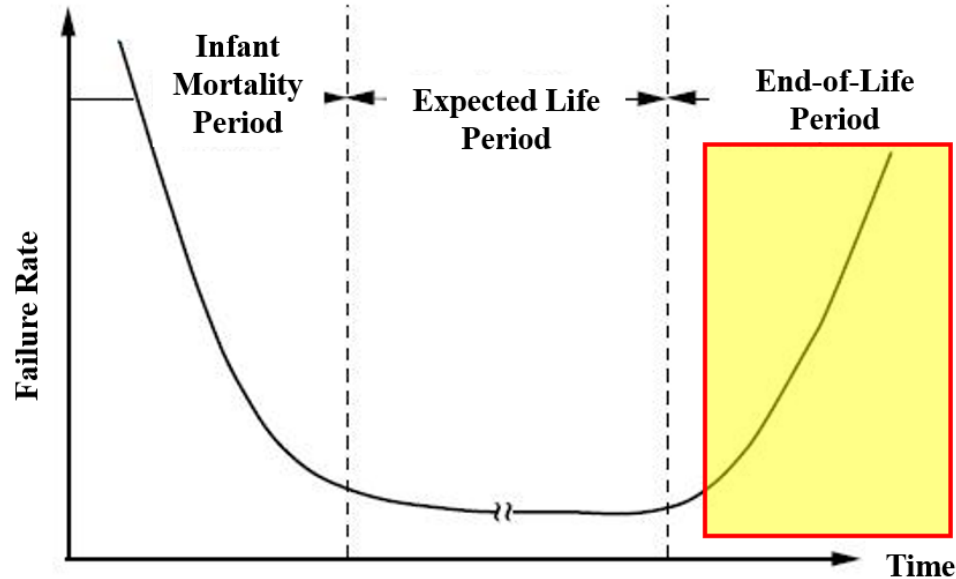
5 **Q. IS THE COMPANY PERFORMING PREEMPTIVE REPLACEMENTS**
6 **FOR TRANSMISSION EQUIPMENT INCLUDED IN THE GRID**
7 **INVESTMENT PLAN?**

8 A. No. The Company disagrees with Staff Witnesses Alvarez and Stephens'
9 characterization of the Company's Grid Investment Plan strategy for transmission
10 assets as "preemptive replacement." The Company relied on its extensive
11 operational and maintenance experience, outage and failure history, and ability to
12 extend asset expected life to determine the age at which it should replace
13 transmission assets within the Grid Investment Plan. In addition, the Company
14 reviewed, analyzed, and compared its replacement assumptions against industry
15 expected life ages for the transmission equipment to be replaced in the Grid
16 Investment Plan.

17 As the Company testified during direct hearings, the bathtub curve is utilized to
18 determine the variation of equipment failure rate with respect to time. The bathtub
19 curve presented in Witness Alvarez and Stephens' testimony is based upon the
20 *estimated useful life* of a hypothetical piece of equipment. In contrast, the bathtub
21 curve, as illustrated in Figure 1 below, is based on the *expected life of an asset*,
22 which is defined as the life expectancy of the Company's equipment. The life
23 expectancy of equipment is supported by internal maintenance procedures, past
24 experiences, equipment specifications, and monitoring of equipment. It is important
25 to note that estimated useful life and expected life are two very separate and distinct
26 terms.

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FIGURE 1: Bathtub Curve for Expected Life



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Witnesses Alvarez and Stephens mistakenly point to the *middle* of their estimated useful life bathtub curve and misrepresent the point at which the Company is replacing transmission equipment as part of the Grid Investment Plan. However, the Company is replacing equipment in the “end-of-life period” where failures occur at an exponential rate due to age-related degradation of equipment. The Company is strategically targeting transmission projects within this “end-of-life period” in a controlled and planned manner to prevent customer interruptions, catastrophic equipment failure, and better manage replacement costs for customers. As mentioned in several discovery requests, the cost of replacing transmission equipment that has catastrophically failed is 2 to 13 times the cost of replacing this equipment in a planned manner. Within this context and background, the Company strongly maintains that it is not performing preemptive replacement on its transmission equipment as part of its Grid Investment Plan.

1 **Q. WHEN FAILURES OCCUR FOR AGED EQUIPMENT ON THE SYSTEM,**
2 **SHOULD THE COMPANY SOLELY DEPEND ON SPARE EQUIPMENT**
3 **BEING AVAILABLE TO REPLACE THE FAILED EQUIPMENT AS**
4 **SUGGESTED BY STAFF WITNESSES?**

5 A. No. Solely depending on spare equipment to supplement failed equipment would
6 present both operational and supply chain challenges if failures occur. The
7 Company's equipment stock levels are aimed to address emergency replacements
8 based on historical failure rates and other factors. The current stock levels are
9 agreed upon by Integrated Transmission System ("ITS") Participants, which along
10 with customers, bear the cost of the spare equipment pool. If the Grid Investment
11 Plan is not continued, 44% of substation transformers and 37% of substation
12 breakers will have exceeded their Company expected life by 2031. With having
13 such a large amount of equipment at or nearing the "end-of-life" period at the same
14 time, the Company is concerned that the existing spare equipment stock will not be
15 able to keep up with the replacement demand for failed equipment. For example,
16 the Company's current stock levels for substation transformers represents 3% of
17 the total population transformers on the system. Furthermore, there are 171
18 different types of transformers on Georgia Power's system. The Company currently
19 only has spare transformers available for 38 of the 171 transformer types, with
20 many of the available transformer spare counts being limited to only one unit on
21 hand.

22 Due to industry supply chain challenges, the lead times for all substation equipment
23 are longer than the Company has seen in many years, with average substation
24 transformer lead times increasing from approximately six months to three years.
25 These lead times continue to grow as other utilities invest in their system and global
26 pressures on the supply-chain for grid infrastructure continue. As transmission
27 equipment gets older and failure rates increase, the Company and customers will
28 be negatively impacted given the number of spares in existing inventory. The

1 Company could choose to increase its spare equipment pool, but this would also
2 negatively impact customers, as keeping too much spare inventory would lead to
3 higher expenditures and higher carrying costs. Depending on spare equipment
4 means that the Company would wait for equipment to fail before it acts. The
5 Company is strongly opposed to such an approach. The Grid Investment Plan offers
6 a controlled, programmatic, multi-year approach to replacing aging transmission
7 assets in a way that reasonably accounts for these operational and supply chain
8 considerations.

9 *Distribution Grid Investment*

10 **Q. DOES THE COMPANY AGREE WITH STAFF’S PROPOSED**
11 **REDUCTIONS TO THE DISTRIBUTION PORTION OF THE GRID**
12 **INVESTMENT PLAN, AND THE OVERALL ASSERTION “THERE IS NO**
13 **PENDING RELIABILITY EMERGENCY”?**

14 A. No, the Company does not agree that the Basic Insulation Level (“BIL”) and
15 Undergrounding investment packages, which make up approximately 85% of
16 Distribution Grid investments, should be removed from the program. Nor does the
17 Company agree with the statement that “there is no pending reliability
18 emergency.”⁵ Georgia Power’s system reliability will continue to worsen every
19 year that investments are not made. Between 2013 and 2021,⁶ the Company’s
20 system average interruption duration index (“SAIDI”) worsened by approximately
21 44% and system average interruption frequency index (“SAIFI”) worsened by
22 approximately 10%. For a subset of feeders (also referred to as circuits) in the
23 system, and the customers on those feeders, the decline in reliability is even more
24 pronounced. This worsening reliability has significant negative impacts on

⁵ Trade Secret Testimony of Paul J. Alvarez and Dennis Stephens, p. 2, lines 23 – 24.

⁶ Georgia Power reliability performance 2014 - 2021, as reported by the Energy Information Administration.

1 customer experience⁷ due to more frequent and longer outages, as well as increases
2 in the economic cost incurred by customers.

3 It is within this context, and with extreme care, that the Company created the
4 Distribution portion of the Grid Investment Plan, which is designed to ensure
5 lasting reliability improvements while minimizing the total cost to the customer.
6 Removing the BIL and Undergrounding investment packages from the Grid
7 Investment Plan would result in significantly longer and more frequent outages
8 across the system, as these packages are the best way to permanently address the
9 root causes of outages on these feeders. In the absence of these investments, the
10 Company would achieve an end-state SAIDI of approximately 127 by 2031,
11 essentially equal to the program starting point SAIDI in 2019, compared to the Grid
12 Investment Plan's current projected end-state of approximately 80. Therefore, the
13 Staff's recommendations would maintain the system-level SAIDI at third quartile
14 levels.

15 **Q. IS THE REVISION TO THE COMPANY'S END-STATE SAIDI FOR THE**
16 **DISTRIBUTION PORTION OF THE GRID INVESTMENT PLAN A**
17 **REFLECTION OF REDUCED RELIABILITY EXPECTATIONS, AS**
18 **CLAIMED BY STAFF?**

19 A. No. The revision to the end-state SAIDI targeted in the Company's Distribution
20 portion of the Grid Investment Plan is a result of lessons learned from the first three
21 years of implementation and not a reflection of changed reliability expectations. In
22 fact, the Company has seen better than expected reliability improvements from the
23 set of investments that have completed construction. Initial results indicate an
24 improvement of approximately 65% in both SAIDI and SAIFI for Grid projects that
25 have been completed for over a year and cycled through both a winter and summer

⁷ Response to STF-WG-2-7(j), Docket No. 42516.

1 peak since completion.⁸ The investments are working and are delivering improved
2 reliability for Georgia Power's customers.

3 As outlined in our direct testimony, the Company refined certain components of the
4 Grid Investment Plan based on insights and lessons learned in the first three years
5 of the program:

- 6 • Georgia Power confirmed that the overall strategy and economic rationale
7 supporting the Grid Investment Plan is optimal for customers. The specific
8 investment packages deployed are producing expected benefits and
9 delivering positive results.
- 10 • The total cost required to deliver individual investments is higher than the
11 Company originally projected because of increases in scope (*e.g.*, additional
12 automation devices required) and in the cost of work (*e.g.*, inflation, COVID
13 shortages).
- 14 • Undergrounding remains the most effective solution for improving
15 customer reliability but, as investment costs have increased across the
16 program, the use of Undergrounding should be carefully evaluated to ensure
17 it is used only where it is the most efficient solution.

18 Given the learnings above, the Company reassessed and refreshed the Distribution
19 portion of the Grid Investment Plan, using the same methodology used in the 2019
20 Rate Case, to ensure that the investments being made continue to result in the lowest
21 total cost to customers. As a result of this evaluation, the Company determined that
22 the set of distribution investments in the best interests of customers are projected to
23 deliver an 80 end-state SAIDI as compared to the 65 end-state SAIDI included in
24 the 2019 rate case plan, which is still first quartile results compared to industry
25 peers. The Company considers this intermittent refinement of the 10-year Grid
26 Investment Plan to be essential for ensuring that customer capital is managed
27 responsibly.

⁸ STF-WG-2-36 Trade Secret Attachment provided in response to STF-WG-2-36(c).

1 **Q. WHY DID THE COMPANY ELECT TO OPTIMIZE THE GRID**
2 **INVESTMENT PLAN AT THE SYSTEM RATHER THAN FEEDER**
3 **LEVEL?**

4 A. The Grid Investment Plan optimizes benefits at the system level rather than the
5 feeder level because the cost of system reliability is borne by all customers served
6 by Georgia Power. In other words, the explicit cost for capital investment and
7 ongoing O&M expense for the grid is paid for by all customers, regardless of each
8 customer's reliability experience and regardless of whether the customer's
9 individual feeder is included within the Grid Investment Plan. The Company
10 intentionally chose to optimize benefits across the *system* to ensure the investments
11 made were in the best interest of *all* customers instead of just the subset of
12 customers served by an individual feeder.

13 **Q. DOES THE COMPANY'S DISTRIBUTION PORTION OF THE GRID**
14 **INVESTMENT PLAN IGNORE A FEEDER-BY-FEEDER ANALYSIS AS**
15 **SUGGESTED BY STAFF WITNESSES ALVAREZ AND STEPHENS?**

16 A. No. Staff Witnesses Alvarez and Stephens propose that the Company conduct a
17 root cause analysis for every feeder on the Company's system, which implies that
18 the Company has not done such analysis. However, this is a misconception. In fact,
19 each and every distribution investment within the Grid Investment Plan is evaluated
20 on a feeder-by-feeder basis with a root cause analysis. The Company does exactly
21 the level of analysis suggested by Staff Witnesses Alvarez and Stephens.

22 **Q. PLEASE DESCRIBE THE FEEDER-LEVEL ROOT CAUSE ANALYSIS**
23 **THE COMPANY CONDUCTS FOR POTENTIAL GRID INVESTMENTS.**

24 A. To evaluate a distribution feeder for the Grid Investment Plan, first, the Company
25 aggregates all the pertinent and available data across the system. This data begins
26 with five years of total reliability performance for each feeder as measured by

1 SAIDI, SAIFI, customer minutes of interruption (CMI), and frequency of different
2 outage event causes. The initial ‘hurdle’ for any feeder to qualify for investment is
3 that the feeder has had sustained poor performance over the past five years.

4 The Company then undertakes a second evaluation to determine the root causes of
5 outages on each feeder. In this step, the Company disaggregates every feeder’s
6 reliability performance to understand the events that caused those outages. For
7 example, the Company evaluates what percentage of a feeder’s outages were the
8 result of vegetation, vehicles, animals, or weather and how that percentage
9 compares to the rest of the system. An evaluated feeder qualifies for a distribution
10 investment package that would permanently resolve the outage cause(s) only if it
11 experiences a higher percentage of outages driven by that particular cause(s) than
12 the system average. In this way, the Company deploys standard, repeatable criteria
13 systematically across all feeders to identify outliers in each category of outage
14 cause.

15 Therefore, prior to optimizing the plan, the Company has completed a feeder-by-
16 feeder, root cause analysis on the entire Distribution system. Through this analysis,
17 the Company determines whether a feeder should be considered for *any* investment
18 and, if so, which of the six possible investment options specifically would address
19 the root causes of reliability issues on that feeder.

20 **Q. PLEASE DESCRIBE HOW THE COMPANY SELECTS FEEDERS FOR**
21 **INVESTMENT AFTER CONDUCTING THE ROOT CAUSE ANALYSIS.**

22 A. For each of the possible investment packages identified during the root cause
23 analysis, the Company projects the costs and the reliability benefits specific to
24 deploying qualified investment package(s) on each feeder. The cost and benefit for
25 each investment will vary depending on unique characteristics of each feeder, such
26 as starting reliability performance and number of line miles to be worked.

1 The Company then evaluates the impact of all possible combinations of feeder level
2 investments to determine the final investment plan that provides the best reliability
3 and the lowest total cost to customers. To do this, the Company evaluates the total
4 cost to all Georgia Power customers of each potential investment plan and selects
5 the plan that minimizes total cost to customers across the system— inclusive of the
6 cost of investment, the cost of remaining outages, and the cost of O&M that
7 customers bear. In this fashion, the Company considers the direct cost of
8 investments as well as the costs customers bear from increased outages related to
9 not investing in some potential investments. The Company acknowledges that it
10 has an obligation to provide reliable electric service and minimize outages for all
11 customers and, therefore, must evaluate the total cost to deliver the best plan for all
12 of its 2.7 million customers.

13 **Q. DID STAFF WITNESSES ALVAREZ AND STEPHENS PROVIDE**
14 **ADEQUATE SUPPORT FOR THEIR ASSERTION THAT BIL AND**
15 **UNDERGROUNDING ARE NOT COST EFFECTIVE?**

16 A. No, the Company fervently disagrees with Staff's assertions that the BIL and
17 Undergrounding packages are not cost-effective.⁹ In executing their cost
18 effectiveness analysis, Staff systematically underestimated investment benefits by
19 not accurately representing the cost to customers of foregoing BIL and
20 Undergrounding:

- 21 • First, Staff Witnesses Alvarez and Stephens did not account for the continued
22 reliability degradation that customers will experience if feeders selected for BIL
23 or Undergrounding are denied investment, underestimating the economic cost
24 to customers of the increased outages.
- 25 • Second, Staff did not quantify the outage repair-related and vegetation-related
26 O&M expenses that will be incurred if these feeders are removed from the Grid
27 Investment Plan.

⁹ Trade Secret Testimony of Paul J. Alvarez and Dennis Stephens, p. 3, line 25.

1 In contrast, the Company has taken extreme care to account for all costs and
2 benefits that will be experienced by customers during the formulation of the Grid
3 Investment Plan. The Company has the utmost confidence that the distribution
4 investments that are part of the Grid Investment Plan are in the best interests of
5 customers, resulting in the greatest reliability benefits for the lowest total cost to
6 customers.

7 **Q. DID STAFF WITNESSES ALVAREZ AND STEPHENS PROVIDE**
8 **ADEQUATE SUPPORT FOR THEIR RECOMMENDATION THAT THE**
9 **COMPANY INCREASE VEGETATION MANAGEMENT IN LIEU OF**
10 **THE GRID INVESTMENT PLAN?**

11 A. No. Staff Witnesses Alvarez and Stephens offered no independent analysis to
12 validate the assertion that increased vegetation management is an effective
13 alternative to the BIL or Undergrounding Grid Investment Plan packages.¹⁰ Though
14 vegetation management has an important place in managing overall system
15 reliability, it is a temporary solution that cannot address a variety of other outage
16 drivers, such as vehicles, wildlife, and lightning. During cross examination, Mr.
17 Stephens himself acknowledged that he had made an assumption about vegetation
18 management as a cost-effective alternative.¹¹

19 Staff did not explain how vegetation management could generate the same expected
20 level of reliability improvement as the dedicated investment packages included in
21 the Grid Investment Plan. Georgia Power's current vegetation management
22 program is designed to maintain reliability, not improve it. In addition, Mr.
23 Stephens confirmed during cross examination that no analysis had been done to
24 determine how much it would cost to actually improve reliability through

¹⁰ Trade Secret Testimony of Paul J. Alvarez and Dennis Stephens, p. 47, lines 15 – 16.

¹¹ PSC Docket No.44280 GPC 2022 Rate Case (11/09/2022); Day 2 of Cross Examination, time stamp 1:37:15.

1 vegetation management.¹² Further, many activities fall within the category of
2 ‘vegetation management,’ and Mr. Stephens did not complete any analysis to
3 determine which activities specifically would need to be added or increased to
4 obtain reliability improvements through vegetation management.

5 Finally, Witnesses Alvarez and Stephens proposed a legislated expansion of utility
6 rights of way as a potential approach to improving reliability.¹³ However, Mr.
7 Alvarez confirmed at the hearing that he had not undertaken any analysis of how
8 long it would take or how much it would cost to pass such legislation. As such, PIA
9 Staff failed to demonstrate how its proposed alternatives to the Grid Investment
10 Plan were either less costly or more beneficial than the Company’s proposal.

11 **Q. DID STAFF PROVIDE ADEQUATE SUPPORT FOR THEIR**
12 **RECOMMENDATION THAT THE COMPANY IMPROVE ITS WORST**
13 **PERFORMING FEEDER PROGRAM IN LIEU OF THE GRID**
14 **INVESTMENT PLAN?**

15 A. No. As with its vegetation management recommendation, Staff failed to conduct
16 the analysis required to validate the recommendation that the Company should
17 focus its attention only on feeders that are performing 2.5 times worse than average
18 as part of its ‘Worst Performing Feeder’ program.¹⁴ This lack of analysis is
19 inconsistent with Witnesses Alvarez and Stephens’ own assertions that grid
20 investments should only ever be made if they are cost effective at the feeder level.

21 Staff did not consider the type of investment that would be required to address the
22 root cause of outages on feeders that are performing 2.5 times worse than average.
23 For many of these feeders, BIL and Undergrounding would be the best solution that
24 would address root causes – yet both of these are investment packages within the

¹² PSC Docket No.44280 GPC 2022 Rate Case (11/09/2022); Day 2 of Cross Examination, time stamp 1:35:06.

¹³ Trade Secret Testimony of Paul J. Alvarez and Dennis Stephens, p. 50, lines 2 – 3.

¹⁴ Trade Secret Testimony of Paul J. Alvarez and Dennis Stephens, p. 45, lines 1 – 2.

1 Grid Investment Program that Staff has proposed for removal. Moreover, Staff did
2 not consider the economic or O&M cost for outages that will continue to be
3 experienced on feeders that do not meet PIA Staff’s ‘worst performing’ criteria.

4 **Q. PLEASE EXPLAIN WHY A MORE ROBUST WORST PERFORMING**
5 **FEEDER PROGRAM WOULD NOT BE A DIFFERENTIATED**
6 **ALTERNATIVE TO THE GRID INVESTMENT PLAN.**

7 A. The Distribution portion of the Company’s Grid Investment Plan already
8 encompasses the key qualities that Staff indicates should be part of a more robust
9 ‘Worst Performing Feeder’ program. This includes clear and repeatable criteria to
10 identify poor-performing feeders, a dedicated budget and associated personnel to
11 administer the program, and standard tracking and reporting on the program’s
12 progress.

13 First, the Staff Witnesses Alvarez and Stephens recommend establishing “clear
14 criteria for identifying circuits for additional attention,”¹⁵ and that the Company
15 “compute one or more reliability metrics for each circuit to enable the identification
16 of poor performers.”¹⁶ As is presented in the Customer Benefit Analysis,¹⁷ the
17 Company has clear and specific criteria for each Distribution investment package
18 in the Grid Investment Program. This includes reliability-specific criteria (*e.g.*,
19 SAIDI, SAIFI), physical attribute-related criteria (*e.g.*, overhead vs. underground),
20 and criteria that identify the root causes of the outages (*e.g.*, outages due to
21 vegetation or vehicles, feeder load). Where the root cause is unclear, not
22 addressable, or cost prohibitive, an investment is not made.

23 Second, Staff recommends “that specific budgets for the program be established,”
24 and that there be designated “personnel / organizational accountabilities for

¹⁵ Trade Secret Testimony of Paul J. Alvarez and Dennis Stephens, p. 53, line 10.

¹⁶ Trade Secret Testimony of Paul J. Alvarez and Dennis Stephens, p. 50, lines 13 – 15.

¹⁷ STF-WG-2-8 Trade Secret Attachment in response to STF-WG-2-8, updated k-factor, Table I.2.

1 program administration.”¹⁸ The Distribution portion of the Grid Investment Plan
2 has a designated budget and designated personnel. In the 2019 Rate Case, the first
3 three years of the Distribution portion of the Grid Investment Plan were approved
4 by the Commission. Moreover, since 2019, the Company has established a team
5 solely devoted to the Grid Investment Plan – from program and project managers,
6 to engineers, supply chain personnel, and construction workers on the ground.

7 Last, Staff Witnesses Alvarez and Stephens recommend “standards for tracking
8 spending, projects, and results.”¹⁹ The Company rigorously tracks all spending for
9 the Grid Investment Plan (at both the project and program level), as well as the
10 reliability performance of each Distribution feeder – before, during, and after
11 investment. The Company reports on the Grid Investment Program performance
12 during the Company’s rate case and makes itself available to respond to any data
13 requests on the Grid Investment Program, as evidenced by the substantial volume
14 of Grid-related data requests that were responded to in the current case. The fact
15 that the Company has robust standards for tracking spending, projects, and results
16 is evidenced by the adjustments made by the Company in the overall plan and
17 optimal range for investment.

18 The Distribution portion of the Grid Investment Plan encompasses the very
19 qualities that Staff recommends should be part of the Company’s ‘Worst
20 Performing Feeder’ program and should be approved as is without modification.

21 *DERMS and Rules and Regulations Section G Recommendation*

22 **Q. ARE CURRENT SOFTWARE SYSTEMS SUFFICIENT ENOUGH TO**
23 **EFFICIENTLY MANAGE THE GROWING AMOUNT OF DISTRIBUTED**

¹⁸ Trade Secret Testimony of Paul J. Alvarez and Dennis Stephens, p. 53, lines 13 – 14.

¹⁹ Trade Secret Testimony of Paul J. Alvarez and Dennis Stephens, p. 53, lines 12 – 13.

1 **ENERGY RESOURCES (“DER”) THAT WILL BE INTERCONNECTED**
2 **ON THE SYSTEM?**

3 A. No. While current software systems allow for the monitoring of power flows and
4 equipment statuses, they lack the enhanced monitoring and operational capabilities
5 necessary to allow for the optimization of an electric system that takes full
6 advantage of a proliferation of DER. The applications currently in place are not
7 capable of managing the substantial number of DERs expected to connect to the
8 grid in the coming years. As more DER are added to the system, it is essential for
9 the Company to have visibility, predictability, and control (where applicable) of
10 these resources. Failure to do so could compromise the Company’s ability to
11 accurately forecast and optimize the full array of generation resources, and also
12 negatively impact power quality and reliability. Further, a system operator will not
13 be able to process the significant amount of data coming in and make informed
14 decisions quickly enough to optimize grid operation if using current software
15 systems.

16 In contrast, a DERMS fully integrated with the Company’s other grid control
17 systems unlocks the potential to continually optimize larger portions of the grid and
18 solve for a variety of constraints, such as economic dispatch, Volt/VAR
19 optimization, and reliability. Additionally, DERMS will allow the Company to
20 consider demand side resources alongside supply side resources in future IRPs, as
21 ordered by the Commission in the 2022 IRP. The Company’s implementation of
22 DERMS will allow for maturation of the solution while thousands or tens of
23 thousands of additional discrete DER are connected to the grid. If DER growth is
24 unrestricted without the installation of DERMS, the Company risks a loss of grid
25 control, which would compromise grid reliability and stability. A DERMS solution
26 is a natural, logical, and necessary step for the Company to prepare for the growth
27 and integration of variable and distributed energy resources.

1 **Q. COULD THE COMPANY DELAY ITS DERMS PROGRAM UNTIL DER**
2 **ADOPTION IS HIGHER?**

3 A. No. There are significant risks to grid stability if the Company were to delay
4 implementing DERMS. Beginning implementation of a DERMS solution now
5 allows for the full DERMS capabilities envisioned by the Company to be developed
6 in parallel with increasing DER penetration across the electric grid. Further, the
7 complexity of integrating DERMS with the Company's existing critical software
8 systems will require a significant amount of time. Undertaking DERMS over the
9 next three years reduces the risk of restricting DER interconnections in the future
10 because of a lack of DER forecasting, control, and optimization capability.

11 **Q. IS THE INTENT BEHIND THE COMPANY'S PROPOSED EDITS TO**
12 **SECTION G OF THE RULES AND REGULATIONS TO REQUIRE**
13 **UNCONDITIONAL ACCESS AND CONTROL OF CUSTOMER**
14 **GENERATORS, AS STAFF SUGGESTS?**

15 A. No. The Company proposed requiring that the customer generation facilities
16 interconnecting to the Company's electric system include a communications
17 interface, installed and maintained by the customer, that supports information
18 exchange with, and control by, Georgia Power so that the Company may continue
19 to operate the electric system in a safe, reliable, and efficient manner. The proposed
20 requirement to allow for communication and increased visibility to DERs operating
21 in parallel with the system is critical to maintaining the system's safety and
22 reliability. As the number of distributed generators grows, the ability to
23 communicate and potentially interact with customer generation will allow for
24 additional growth that might not otherwise be possible. Notably, the Company has
25 only requested this change for customer generation facilities sized 250 kW and
26 above that operate in parallel with the Company's electric system for more than
27 100 milliseconds.

1 **Q. DID THE COMPANY INTEND FOR THIS PROPOSED CHANGE TO BE**
2 **CONSISTENT WITH THE REQUIREMENTS OF IEEE-1547?**

3 A. Yes. The Company intends for the proposed changes to be consistent with the
4 requirements of IEEE-1547, as they may be amended from time to time.

5 **Q. WHAT IS THE JUSTIFICATION FOR THE COMPANY’S REQUEST TO**
6 **REQUIRE EXISTING CUSTOMER GENERATORS TO INSTALL A**
7 **LOCAL INTERFACE FOR COMMUNICATION AND CONTROL?**

8 A. Utility visibility and control of customer generation facilities becomes an essential
9 function as the adoption of DER increases. Without visibility, it is impossible for a
10 utility to ascertain the status, availability, real time actual output, and forecast
11 availability of a resource. Without control, it is impossible for a utility to update
12 functional settings such as active power setpoint, frequency response, and reactive
13 power modes in response to real time grid conditions. Both visibility and control
14 are necessary functions to enable real time economic optimization of the electric
15 grid. The Company is requesting that all existing and future customer generation
16 facilities be equipped with a local communications interface so that these facilities
17 will be available to the Company’s eventual DERMS solution. Without visibility
18 and control capability on existing customer generation facilities, gaps will be
19 present in the Company’s ability to be fully aware of the interaction of those
20 facilities with other generation facilities and the rest of the electric grid.

21 *Revenue Requirement Impacts*

22 **Q. WITH RESPECT TO THE RECOMMENDED CAPITAL REDUCTIONS**
23 **FOR THE GRID INVESTMENT PROGRAM, DID PIA STAFF**
24 **CORRECTLY CALCULATE ITS REVENUE REQUIREMENT IMPACT?**

25 A. No. PIA Staff assumed the projected capital expenditures for the Grid Investment
26 Program will close to plant-in-service as they are incurred, thus incorrectly

1 assuming the capital expenditures are the same as closures in its calculation of the
2 revenue requirement impact. Since the capital expenditures are projected to close
3 to plant in service later than when they are incurred in the Company's filing,
4 assuming closures are the same as capital expenditures artificially inflates the
5 reduction of average plant in service balances based on their recommendation. This
6 results in a significantly overstated revenue requirement reduction for the test year
7 and years 2023 through 2025. In addition, PIA Staff did not consider the impact of
8 removing the related accumulated deferred income taxes (ADITs) in their proposed
9 Grid Investment Program capital reduction, which also caused the revenue
10 requirement reduction to be overstated.

11 IX. RECENT TAX LEGISLATION

12 **Q. IS THE COMPANY ACTIVELY ANALYZING AND PURSUING THE**
13 **BENEFITS PROVIDED IN THE RECENTLY PASSED INFLATION**
14 **REDUCTION ACT ("IRA") AND INFRASTRUCTURE AND**
15 **INVESTMENT JOBS ACT ("IIJA") LEGISLATION, AND DOES THE**
16 **COMPANY PLAN TO PASS THOSE BENEFITS ON TO CUSTOMERS?**

17 **A.** Yes. The Company is in the process of assessing the various potential impacts of
18 the IRA and IIJA. The Company expects the IRA and IIJA will benefit customers
19 through reduced project costs and lower income taxes. The Company has already
20 identified several benefits from the IRA, with the details of those benefits provided
21 in response to data request STF-LA-5-14. The Company continues to seek out
22 additional opportunities under the new legislation that will benefit customers;
23 however, there are many components of the IRA and IIJA that will take time to
24 evaluate, and significant guidance from the IRS and Treasury will be necessary to
25 administer the tax law changes in both Acts. The Company fully intends to pass
26 any tax benefits related to the IRA and the IIJA on to customers.

1 **Q. BASED ON THE COMPANY’S INITIAL ANALYSIS OF THE IRA, WHAT**
2 **OPPORTUNITIES FOR TAX CREDITS WERE IDENTIFIED?**

3 A. The Company’s initial analysis of the IRA identified approximately \$44 million of
4 additional tax credit benefits related to projected, qualified renewable energy and
5 electric vehicle investments. The largest benefit identified in the Company’s initial
6 analysis relates to investment tax credits (“ITC”) associated with the Mossy Branch
7 battery storage project. The Mossy Branch project, which is projected to go into
8 service in 2023, is a project that the Company currently believes would qualify for
9 a 30% ITC. Additionally, with the Commission’s approval, the Company can opt-
10 out of the traditional ITC normalization structure which would result in giving
11 customers all the ITC benefit in the year the project goes into service instead of
12 over the life of the asset. The Company also expects to generate ITCs on the
13 McGrau Ford battery facility; however, those credits are not expected to be
14 generated until after 2025 when the facility is expected to be placed into service. In
15 addition, the Company’s initial analysis shows the IRA will provide more options
16 to pursue and compete for lower cost solar energy investments as a result of
17 expanded tax credits. Through the IRA, the Company now has an option to choose
18 between either the traditional ITC or a new Production Tax Credit (“PTC”) for
19 Company-owned solar projects; however, the Company is still not able to claim
20 ITC or PTCs on solar resources procured through purchased power agreements,
21 which account for the majority of the Company’s new solar resources expected to
22 come online in years 2023 through 2025. For new Company-owned solar facilities
23 projected to come online in those years, the Company estimates the PTC option
24 will provide approximately \$0.4 million of additional benefits for customers in
25 2025 related to projected ash pond solar investments at Plant McIntosh, Plant
26 McDonough, and Plant Hammond.

27 Since the filing of direct testimony, the Company identified IRA benefits for which
28 it may qualify. Georgia Power estimates that the Hydro Modernization projects

1 approved by the Commission in the 2019 and 2022 IRP is currently estimated to
2 provide approximately \$3 million of tax benefits for the three years 2023 through
3 2025. The Company also anticipates qualifying for credits on the Integrated
4 Hydrogen Microgrid project that was approved by the Commission in the 2022 IRP.

5 **Q. HAS THE COMPANY PERFORMED AN INITIAL ANALYSIS OF**
6 **QUALIFICATIONS FOR PTCs ON EXISTING NUCLEAR FACILITIES**
7 **AVAILABLE THROUGH THE IRA?**

8 A. The Company has performed initial analysis on the zero-emission nuclear
9 production tax credits on existing nuclear facilities currently in service. Based on
10 current guidelines in the IRA, it does not appear the Company will be eligible for
11 the zero emission PTCs on the Company's nuclear facilities currently in operation;
12 however, the Company is hopeful additional guidance from the Treasury will be
13 issued on the gross receipts calculation used to calculate the credits that may allow
14 the Company to qualify for these credits for the benefit of customers.

15 **Q. HOW DOES THE COMPANY PROPOSE TO COMMUNICATE RESULTS**
16 **OF THE IRA AND IIJA ANALYSIS TO THE COMMISSION?**

17 A. The Company proposes to use existing mechanisms for data communication and
18 discovery for this and future rate proceedings to provide tax and other savings
19 resulting from the IRA and IIJA, noting that there should be benefits associated
20 with the IRA and IIJA well beyond the period of this three-year ARP. The Company
21 can agree to record these tax benefits to a regulatory liability for future
22 consideration by this Commission to be used for the benefit of customers as soon
23 as possible.

24 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

25 A. Yes.

1 MR. HEWITSON: And with your permission, I'll
2 ask Mr. Abramovitz to summarize the testimony of the
3 panel.

4 MADAM CHAIR PRIDEMORE: Please go forward,
5 Mr. Abramovitz.

6 MR. ABRAMOVITZ: Good morning, Madam Chair and
7 Commissioners. Ms. Adams, Mr. Houston, Mr. Robinson
8 and I each thank you for the opportunity to be here
9 today.

10 We're here today to respond to some of the
11 changes proposed by PIA Staff and Intervenors to
12 Georgia Power's revenue requirement in this case. We
13 continue to recommend that the Commission maintain
14 the constructive regulatory environment effectuated
15 through an Alternate Rate Plan, that has benefited
16 Georgia Power's customers for decades.

17 This Commission's constructive regulatory
18 policies have created a sustained period of high
19 customer satisfaction, high reliability, and rates
20 below the national average, and have contributed to
21 Georgia Power consistently -- Georgia being
22 consistently ranked as the best state in the nation
23 in which to do business.

24 This Commission has a well-deserved national
25 reputation for maintaining a consistent and balanced

1 regulatory environment that benefits all
2 stakeholders.

3 Many of the recommendations and positions taken
4 by the PIA Staff and Intervenor appear to ignore
5 what has changed over the past three years, as well
6 as what has remained constant since the 2019 rate
7 case order.

8 Changes over the past three years include:

9 The emergence of a global pandemic, rampant and
10 rapid inflation that has increased costs for
11 businesses and consumers alike, growing pressure on
12 supply chain and labor markets, significant increases
13 in the federal funds rate and cost of borrowing, and
14 evolving customer needs, demands and requests for
15 increased distributed energy resources and
16 carbon-free energy.

17 What has remained constant includes: This
18 Commission's continued constructive and balanced
19 approach that ensures customers continue to receive
20 clean, safe, reliable, and affordable electricity,
21 even during a global pandemic, the importance of
22 financial integrity and credit quality, which is
23 never more evident than during times of global
24 uncertainty and financial market volatility.

25 At Georgia Power, customers continue to be at

1 the center of everything we do. Georgia Power's
2 continued excellent customer service and reliability
3 performance with rates below the national average,
4 and, finally, the state of Georgia continues to be
5 ranked as one of the best places for business as
6 Georgia's economy has continued to grow with economic
7 development reaching all-time highs.

8 Taking the past three years as context, many of
9 the recommendations made by parties in this case
10 would cause direct harm to customers by turning the
11 well-designed and balanced regulatory structure
12 currently in place on its head, ultimately
13 undermining the financial health and integrity of
14 Georgia Power. These recommendations are
15 unacceptable to the Company, and we believe they
16 should be unacceptable to this Commission as well.

17 Before I continue, let me please note that not
18 addressing a particular party's position in our
19 rebuttal or this summary does not indicate the
20 Company's support or indifference to such a position.

21 First, PIA Staff and several Intervenors have
22 proposed modifications to the Alternate Rate Plan or
23 ARP. These modifications are fundamentally
24 inconsistent with the concept of the ARP that
25 benefits customers and incentivizes the Company.

1 Georgia Power does not support the recommendations to
2 narrow the earnings band, set the top end of the
3 earnings band at an artificially low level, or
4 eliminate the sharing mechanism for earnings above
5 the top end of the band.

6 These alterations to one of the key components
7 of the 3-year ARP, an authorized earnings band with
8 sharing of revenues, would effectively create an
9 earnings cap, potential rate instability, and be
10 counterproductive to the goal of incentivizing the
11 Company to continue to drive efficiencies in the
12 business for the benefit of customers.

13 In addition, the recommendations by Staff and
14 other intervenors to revise the content and estimates
15 supporting the Company's annual compliance filings
16 edges ever closer to having abbreviated-rate cases
17 every year, once again encouraging less
18 predictability in rates.

19 These proposed modifications undercut core
20 aspects of the ARP and are unacceptable. Absent an
21 ARP agreed to by the Company, this case will result
22 in a traditional rate case order, which would
23 eliminate key customer benefits including the rate
24 predictability inherent in the three-year rate plan
25 and remove any revenue sharing.

1 Second, the Company adamantly opposes the
2 return to equity setpoint and capital structure
3 recommendations put forth by Staff and several
4 Intervenors. If adopted, PIA Staff's recommended 105
5 basis point ROE reduction from the Company's current
6 setpoint would represent the largest single ROE
7 reduction for Georgia Power in decades.

8 When considering Mr. Coyne's expert market
9 analysis that supports a 50 basis point ROE increase
10 along with the Company's superior operational
11 performance over the last three years, a 105 basis
12 point reduction to the Company's current ROE setpoint
13 would be particularly egregious and unnecessarily
14 punitive.

15 Many of these same parties also propose to
16 reduce the equity portion of the Company's capital
17 structure. Most notably, the PIA Staff recommended
18 reduction from 56 percent to 51 percent starting in
19 the second year of the ARP.

20 The Company's current capital structure was
21 approved by this Commission in response to the 2017
22 Tax Cut and Jobs Act and further modified in the
23 Company's last rate case. The approved capital
24 structure in the 2019 Rate Case was in direct
25 response to the enactment of the 2017 Tax Cut and

1 Jobs Act and was not related to the construction of
2 Vogtle Units 3 and 4.

3 With no changes to that tax law and no
4 correlation to the achievement of in service of
5 Vogtle Units 3 and 4, the PIA Staff's suggested 500
6 basis point equity ratio reduction from the level
7 deemed appropriate by this Commission just three
8 years ago has no justification or merit.

9 Simply put, after considering Mr. Coyne's
10 market analysis, the lasting impacts of the Tax Cut
11 and Jobs Act, and the Company's performance over the
12 last three years, any radical reduction in the
13 Company's requested ROE setpoint and 56 percent
14 equity ratio would be unprecedented and unwarranted,
15 with such severe changes significantly impairing the
16 Company's financial integrity and its ability to
17 raise capital at reasonable cost and upon reasonable
18 terms for the benefit of customers.

19 Third, PIA Staff has asserted that the Company
20 can arbitrarily reduce its Operations and Maintenance
21 ("O&M") expense based on the past three years as if
22 major outage or maintenance work occurred at the same
23 level every year and that operating through the
24 pandemic years was a normal indication of Georgia
25 Power's cost to serve our customers.

1 The Company's O&M requests in this case were
2 thoughtfully designed to support the next three years
3 of critical function and operation of Georgia Power
4 to ensure that we can continue to provide clean,
5 safe, reliable, and affordable electric service with
6 exceptional customer service to our customers.

7 Fourth, PIA Staff has also proposed to
8 substantially reduce or eliminate transmission and
9 distribution investments required to support the
10 long-term reliability and resiliency of our electric
11 system, seemingly without any consideration of the
12 long-term impacts to the performance of the electric
13 system for our customers and the state.

14 The Company cannot delay or take shortcuts in
15 implementing these grid investments, which are
16 necessary to address aging transmission
17 infrastructure and improve reliability performance
18 for nearly 1.4 million customers throughout this
19 state.

20 In conclusion, we understand this Commission
21 must consider the cost of electric service when
22 evaluating Georgia Power's cost to serve our
23 2.7 million customers, and we have thoughtfully and
24 appropriately balanced our request in this proceeding
25 with both the financial impacts to, and needs of, our

1 customers. We operate a capital-intensive business
2 and have the privilege and obligation to serve our
3 customers in this rapidly-changing world.

4 The changes that PIA Staff and many of the
5 intervening parties propose are ill-advised and fail
6 to consider the Company's ability to sufficiently
7 access capital markets upon reasonable terms in order
8 to attract the substantial capital necessary to
9 continue providing our customers with clean, safe,
10 and reliable electric service they deserve and
11 expect.

12 This Commission's consistent application of a
13 constructive regulatory framework provides for a
14 financially healthy utility, rewards for superior
15 performance to customers, and over the long term has
16 resulted in rates below the national average. Many
17 of the recommendations by parties in this case are
18 extreme and seek to undo this constructive framework,
19 and ultimately put customers and the Company at risk.

20 While there are many issues to consider in this
21 case, we ask that you continue to take the long-term
22 view that you have taken in the past. Now is not the
23 time to chart a drastically new course for the
24 regulatory framework in Georgia. We ask you,
25 Commissioners, to approve our proposed rate

1 adjustment in this case so that Georgia Power remains
2 positioned to grow Georgia while continuing to meet
3 the energy needs of our customers and the communities
4 we have the privilege to serve.

5 Thank you for your time and attention.

6 MR. HEWITSON: Madam Chair, the witnesses are
7 available for questions from the Commission as well
8 as cross-examination.

9 MADAM CHAIR PRIDEMORE: Questions from
10 Commissioners?

11 (No response.)

12 MADAM CHAIR PRIDEMORE: Commissioner McDonald?

13 COMMISSIONER MCDONALD: Thank you. This case
14 was filed in June of '13; right -- I mean, June -- in
15 June of --

16 MR. ABRAMOVITZ: Yes, Commissioner McDonald.

17 COMMISSIONER MCDONALD: In preparation for this
18 you started preparing the rate case probably the
19 first of '22 or even before that; right?

20 MR. ABRAMOVITZ: Yes.

21 COMMISSIONER MCDONALD: Has there been anything
22 in the economy of this nation or the economy of the
23 state of Georgia that presents any reason that you
24 might look at where we are today versus where you
25 were when you filed the case? Have conditions

1 changed? Is there anything that might suggest that
2 you either need to file additional or less because
3 what we know today we didn't know in June?

4 MR. ABRAMOVITZ: Yes, Commissioner, that's a
5 very fair question. What I can tell you is the rate
6 of inflation across not only the Georgia economy but
7 the national economy has increased, continued to
8 increase. Although there are reports that, yes, the
9 level has stabilized, the prices are still higher.
10 That includes our cost to serve our customers as
11 well.

12 We tried to account for that in our proposal
13 back in June. It's possible that those assumptions
14 were low, it's possible, but let's see how the next
15 few years play out.

16 I will tell you as prices have increased and as
17 national policy has kind of shifted, you know, I
18 think the chances of economic recession have
19 increased. I'm encouraged by this State's economy
20 and the economic development of this State that
21 Georgia can weather such storm, if you will. But the
22 pressure is there not only on the company's cost to
23 serve customers, but obviously our customers as well.

24 MR. ROBINSON: And, Commissioner, I would add
25 one of the things we've seen in power delivery that's

1 changed since we filed this case, is the availability
2 of material and resources. We used to be able to
3 expect to get our transformers in six months from
4 manufacturers. We're now over three years.

5 So we're looking out, having -- particularly
6 with the economic development that's happening in the
7 state, with the capital maintenance that we're doing
8 on our aging infrastructure, having to look out
9 beyond three years on ordering transformers from
10 manufacturers.

11 COMMISSIONER MCDONALD: One of the things that
12 concerns me is in your answer to the PIA Staff about
13 agreeing to the recommendation of a hundred percent
14 of earnings above the top end. And, of course, your
15 answer is no, you don't agree with that.

16 But in your answer responding to that you say
17 that the company to exceed the top end of the band
18 does not encourage the company to maximize its
19 sufficiency during the period.

20 Does it take a carrot out there to make you
21 operate and manage? Because there are businesses all
22 over this state that have to make adjustments and
23 they make it because they can't meet the needs of
24 their income. But when you say that it takes that
25 carrot to make you be efficient, I don't agree with

1 that.

2 MR. ABRAMOVITZ: So, Commissioner McDonald, let
3 me clarify a little bit. Georgia Power Company has
4 the obligation to always seek out efficiencies to
5 serve our customers in the most efficient manner
6 possible, whether there is a sharing mechanism or not
7 in our ROE band structured in the ARP.

8 Obviously, a financial carrot does help. It
9 does add extra incentive, but in no way would change
10 our practice of always continuing to find the best
11 way to serve our customers in the most cost-effective
12 manner, regardless of the financial carrot, if you
13 would.

14 COMMISSIONER MCDONALD: I was just reading from
15 your response.

16 MADAM CHAIR PRIDEMORE: Any other questions
17 from Commissioners?

18 (No response.)

19 MADAM CHAIR PRIDEMORE: Okay. Georgia Public
20 Service Commission.

21 MR. WALSH: Thank you, Madam Chair.

22 CROSS-EXAMINATION

23 BY MR. WALSH:

24 Q For the record, Dan Walsh on behalf of Public
25 Interest Advocacy Staff.

1 Good morning, Everybody.

2 THE PANEL: Good morning.

3 Q Good to see all of you today.

4 We discussed in the direct round of your
5 testimony that the company is asking to front load its
6 traditional base revenue increase. The staff has since
7 proposed a step increase, and the company on rebuttal is
8 sticking with its request to front load the increase, even
9 though in the 2019 rate case it ultimately agreed to the
10 step increase. Is all of that correct?

11 A (Witness Abramovitz) That is correct. And
12 just to make sure our position is clear here, the reason why
13 we're sticking with that proposed levelized approach is it's
14 the least expensive option for customers, understanding that
15 in the 2019 rate case and in previous rate cases, rates have
16 been set at a more step increase level.

17 Q Approximately how much in annual traditional
18 base rate revenue requirement is associated with 100 basis
19 points of return on equity?

20 A (Witness Abramovitz) I would say approximately
21 \$90 million.

22 Q \$90 million?

23 A (Witness Abramovitz) I may be off on the
24 number.

25 Q I'm sorry?

1 A (Witness Abramovitz) I may be off on the
2 number. I would probably say it's probably closer to, I
3 think -- doing the math off the top of my head, about \$150
4 to 160,000,000 revenue requirement.

5 Q From staff's experts the grossed-up revenue
6 requirement for plan year 2025 would be \$214 million. Does
7 that sound reasonable?

8 A (Witness Abramovitz) Sounds a bit high.

9 Q Well, do you know what the retail rate base for
10 2025 is per the company?

11 A (Witness Abramovitz) It's probably close to
12 \$27 billion.

13 Q And would you accept 28.46 billion?

14 A (Witness Abramovitz) I would.

15 Q Thank you. And the common equity portion of
16 the capital structure for the company's request is
17 56 percent?

18 A (Witness Abramovitz) That's correct.

19 Q Would you accept that if you multiplied those,
20 the earning requirement for the 2025 plan year would be
21 15.9 billion?

22 A (Witness Abramovitz) Subject to check, I'll
23 trust your math.

24 Q Thank you.

25 And just to give you some comfort, it's not my

1 math.

2 So, then, if you were to take a hundred basis
3 points of ROE from the 15.9 billion, that would be
4 multiplying it by 1 percent and that would get you
5 \$159 million; is that correct?

6 A (Witness Abramovitz) Subject to check.

7 Q Subject to check.

8 And then from that, you would have to apply a
9 gross-up revenue conversion factor; correct?

10 A (Witness Abramovitz) That's right.

11 Q And if you applied a 1.34 grossed-up
12 conversion -- grossed-up revenue conversion factor, would
13 you agree that the grossed-up revenue requirement for plan
14 year 2025, subject to check, would be \$213.653 million?

15 A (Witness Abramovitz) Subject to check.

16 Q Okay. Thank you.

17 And with that, if you accept that number
18 then -- and the company is proposing a 250 basis point band;
19 correct?

20 A (Witness Abramovitz) A 250 basis point
21 authorized ROE band?

22 Q Yes.

23 A (Witness Abramovitz) Is that what you're
24 asking?

25 Q Yes.

1 A (Witness Abramovitz) Yes, sir.

2 Q Thank you.

3 So if you have a 250 basis point ROE band, and
4 the grossed-up revenue requirement for plan year 2025 is
5 \$213.6 million, that would mean the difference between the
6 bottom of the band and the top of the band could be
7 approximately \$534 million.

8 Would you accept that, subject to check?

9 A (Witness Abramovitz) Subject to check. But
10 one thing I'll just remind this Commission is, rates aren't
11 set on the ROE band. Rates are set on the ROE set point.
12 And so I appreciate your question that, yes, the company has
13 an avenue or an area to work between of 9 and a half percent
14 return on equity and 12 percent return on equity, per our
15 requests. Rates are not set on 12 percent, they're not set
16 on 9 and a half percent. They're set on the set point,
17 which our current request is 11 percent.

18 Q And I didn't mean to imply otherwise. What I
19 was trying to do is get the amount we're talking about
20 between the bottom end and the top end of the band.

21 A (Witness Abramovitz) Okay.

22 Q Could you refer to page 18 of your testimony.
23 I was going to direct you to lines 24 through 25.

24 A (Witness Abramovitz) And the lines were 24
25 through?

1 Q 24 through 25.

2 A (Witness Abramovitz) Okay.

3 Q And if you want to take a second to look at the
4 broader context you can, but I was just going to point out
5 that in this part of the testimony you say that having a
6 sharing mechanism is essential since it encourages the
7 company to look for efficiencies and process improvements.

8 A (Witness Abramovitz) Yes, and that goes to the
9 earlier conversation Commissioner McDonald and I just had.

10 Q Right. And you would agree, wouldn't you, and
11 I think you may have, but just to find out, you would agree
12 that having an earnings band of 200 to 250 points which
13 allows the company to earn hundreds of millions of dollars
14 above the midpoint without any sharing with customers, that
15 provides an incentive for the company to operate
16 efficiently; correct?

17 A (Witness Abramovitz) Well, it provides
18 incentive, but it also provides risk on the downside. If
19 revenues are lower, if it's -- if temperatures are lower or
20 if our cost structure is not efficient, then we take the
21 risk on that as well.

22 Q Right. But I'm just talking about the
23 incentive you would have, and you would agree that that
24 element of your proposed accounting order would provide the
25 incentive, that the fact that you can earn a significant

1 amount within the band before there's any sharing with
2 ratepayers, that provides incentive?

3 A (Witness Abramovitz) While it does, I think
4 the balance here is that we also have risk on the downside
5 too. It's not all about the incentive.

6 Q Would you also agree that there's some benefit
7 to the company from writing down assets?

8 A (Witness Abramovitz) I'm not sure I understand
9 your question.

10 Q Well, recovery of regulatory assets provides
11 the company with cash sooner, doesn't it?

12 A (Witness Abramovitz) Yes.

13 Q And, again, I think this goes to the
14 conversation you were having earlier with Commissioner
15 McDonald, but it's not your testimony, is it -- well, let me
16 back up. Strike that.

17 I want to ask you about the staff's
18 recommendation above the band, about being split between the
19 refunds to customers and the writing down assets.

20 A (Witness Abramovitz) Okay.

21 Q Okay. It's not your testimony, is it, that
22 providing a benefit to customers of rate reductions provides
23 the company with zero incentive to operate efficiently?
24 That is not your testimony?

25 A (Witness Abramovitz) That is not our

1 testimony.

2 Q Right. So you would agree that there is an
3 incentive, even under staff's proposal, for the company to
4 continue to act efficiently above the band?

5 A (Witness Abramovitz) Yes.

6 Q And you would also agree that the Commission
7 could consider how much the company gets to keep within the
8 band without any sharing with ratepayers in determining
9 what's an equitable treatment of the earnings on top of the
10 band; that's a reasonable consideration for the Commission
11 to take -- to take into account?

12 A (Witness Abramovitz) Yes, that's a reasonable
13 consideration for this Commission.

14 Q Thank you.

15 Now, we also talked during the company's direct
16 generally about how if the Commission did not find the
17 company's proposed alternative rate plan to be reasonable
18 and fair, then it could determine rates under a traditional
19 rate case model. I know that's not the company's
20 recommendation, but is that still your understanding?

21 A (Witness Abramovitz) Yes.

22 Q I'm going to ask you some questions about
23 page 2, lines 26 through 27 of your testimony and on to
24 page 3.

25 A (Witness Abramovitz) Clarify that reference

1 one more time.

2 Q Page 2 near the bottom of the page kind of
3 lines 26 and 27.

4 A (Witness Abramovitz) Thank you.

5 Q In your testimony, have you characterized the
6 staff and intervenors of having proposed radical and harmful
7 changes to the alternative rate plan?

8 A (Witness Abramovitz) Yes, we have.

9 Q And you talk about the staff's proposal to
10 drastically reduce the company's return on equity as well;
11 correct?

12 A (Witness Abramovitz) Drastically reduce the
13 return on equity, drastically reduce the common equity ratio
14 and also the proposal to potentially limit any sharing above
15 the ROE band between customers and company.

16 Q Okay. And just so it's clear for the record,
17 when I said staff's drastic recommendation, that was me
18 saying what your testimony was, not my own.

19 Are you aware that since 2020 the average
20 return on equity award in the industry, in the electric
21 industry is below 9.5 percent?

22 A (Witness Abramovitz) Yes, I believe we talked
23 about that a lot in the direct hearings.

24 Q Okay. And the word radical is defined to mean
25 departing markedly from the usual or customary. Is that

1 your understanding of the word radical?

2 A (Witness Abramovitz) It is. And the reason
3 why we used, I used radical in our testimony is because
4 we're talking about Georgia Power here. We're not talking
5 about the average utility.

6 Q And staff's recommendation, though, of a
7 9.45 percent ROE is not radical compared to what other
8 electric utilities have, in the industry have been
9 receiving, you would agree with that; correct?

10 A (Witness Abramovitz) Well, it's not radical
11 compared to other utilities. It is a radical departure from
12 Mr. Coyne's expert analysis and what this company's ROE has
13 been in the past.

14 Q So you're saying staff's recommendation is much
15 different than what the company's ROE witnesses recommended?

16 A (Witness Abramovitz) Yes, right.

17 Q Now, the company wants an earnings band of 250
18 basis points from 9.5 to 12.0, and is that based on what the
19 company got last time?

20 A (Witness Abramovitz) It is similar, that's
21 correct. I think it's the exact same.

22 Q And staff has proposed a 200 basis point
23 earnings band of 8.45 to 10.45 based on 100 points on either
24 side of staff's recommended ROE of 9.54 percent. Is that
25 your understanding?

1 A That's my understanding.

2 Q Are you aware that staff's proposed earnings
3 band is right in line with the earnings bands that are
4 currently in effect for two of the largest investor-owned
5 utilities in the Commonwealth of Virginia?

6 A (Witness Abramovitz) I'm not aware of that.

7 Q Dominion Energy in Virginia is currently
8 operating under a triannual plan that measures earnings
9 using a band that is 70 basis points above and below its
10 last authorized ROE of 9.35 for an earnings band of 8.65 to
11 10.05, and that's in place for 2021 through 2023.

12 Were you aware of that?

13 A (Witness Abramovitz) I was not.

14 Q And were you aware that Appalachian Power
15 Company of Virginia also has a similar plan?

16 A (Witness Abramovitz) I was not aware, but I am
17 now.

18 Q Thank you.

19 In several of the company's prior alternative
20 rate plans, stock-based compensation has been an issue;
21 correct?

22 A (Witness Abramovitz) Yes. It has been
23 something that has been discussed.

24 Q And is it your understanding that there have
25 been cases where the compensation was required to be funded

1 by shareholders?

2 A (Witness Abramovitz) I think the way I would
3 say it is the compensation wasn't included in our base
4 rates.

5 Q Okay. Stock-based compensation is on top of
6 base pay and the other incentive compensation that is
7 provided in the performance paid plan; isn't that correct?

8 A (Witness Abramovitz) So I want to clarify
9 here. Stock-based compensation, I think is what you're
10 getting to, is a component of total compensation for certain
11 employees at Georgia Power. What I would say is if there
12 wasn't a -- if there wasn't a stock-based compensation
13 incentive, if we were a municipality or cooperative and we
14 were trying to attract the same level and talent of employee
15 that we have here at Georgia Power, we would have to
16 compensate our employees in a similar manner. We choose to
17 use stock-based compensation as one method to ensure that
18 there's some risk for that compensation actually being
19 awarded.

20 Q Stock-based compensation is awarded based on --
21 well, I'll back up.

22 Stock-based compensation is provided to
23 executives and other highly-compensated management; is that
24 correct?

25 A Executives and other high-level executives. I

1 think the compensation is, if you will, comparable to other
2 market participants in the median of the position.

3 Q I guess what -- and I'm sorry if I was unclear.
4 I wasn't trying to imply that -- I wasn't comparing Georgia
5 Power's executives to other executives. What I was
6 saying -- I guess compared to the employment of Georgia
7 Power -- employees at Georgia Power as a whole, the
8 stock-based compensation is available to the more
9 highly-compensated employees; is that fair to say?

10 A (Witness Abramovitz) It's available to the
11 higher-level employees. And, yes, we typically -- if you're
12 at a higher level, whether it's in the state government,
13 federal government, or Georgia Power Company, your
14 compensation will be higher.

15 Q And stock-based compensation, is it correct
16 that it's awarded based on hitting shareholder-oriented
17 targets?

18 A (Witness Abramovitz) Yes, that's one
19 component.

20 Q Is it correct that the investment is tied to
21 how the company's stock does, and if the stock does better,
22 the employees who receive stock-based compensation do
23 better?

24 A (Witness Abramovitz) Yes. It is directly tied
25 to how the stock of Southern Company performs that total

1 shareholder return. And I think I said this in my opening
2 remarks, and it's not rhetoric. The customer is at the
3 center of everything we do. And what I would tell you is
4 that you can't have shareholder value if you don't have
5 customer value. They don't exist separately. They're
6 highly correlated. If our customers don't receive value,
7 then our shareholders don't receive value. It is precisely
8 connected and correlated.

9 Q Ratepayers and shareholders don't always
10 benefit from the same things, do they?

11 A (Witness Abramovitz) I would disagree.

12 Q So if the company receives a higher return on
13 equity, that's good for shareholders, isn't it?

14 A Yes, and it's good for customers, as well, as
15 it balances the financial health of the company and it
16 provides that we have ready access to capital for the
17 benefit of our customers.

18 Q When was the last time a customer group came to
19 this Commission during a rate case and recommended an ROE
20 that was higher than what the company was recommending?

21 A (Witness Abramovitz) I'm not sure.

22 Q I'm not sure either on that one.

23 In this case, the customer groups and the other
24 intervenors that are recommending ROE, they're all lower
25 than the company; right?

1 A (Witness Abramovitz) They are, and that's
2 their position, and I understand that. Our analysis says
3 that the market demands something higher.

4 Q Right. But I'm just saying that the fact that
5 the intervenors and the staff who come here and recommend
6 ROEs to this Commission, the fact that those groups have --
7 I'm going say consistently and in my recollection always --
8 recommended lower ROEs to the extent that they make a
9 recommendation than what the company recommends. Don't
10 you -- wouldn't you take something from that, that they
11 might not see an increase in ROE for the company to be the
12 same benefit to what the company shareholder may see it?

13 A I can't presuppose what an intervenor or a
14 customer group may think. What I can say is that,
15 considering our superior performance, our high customer
16 satisfaction, the reliability of resiliency, and rates below
17 the national average, there is appropriate balance between
18 the ROE that we've requested, the ROE we've earned in the
19 past, and the equity band authorized by this Commission.

20 Q And I'm not asking you to -- I'm not asking on
21 ROE questions today on that. I'm asking about the alignment
22 of the interests, and I appreciate your answer on that.

23 But would you agree that if ratepayer and
24 shareholder interests were identical and always the same
25 that there would be much less need for -- to have a Public

1 Service Commission to regulate the Georgia Power Company?
2 Wouldn't you just be able to operate and everything you did
3 would be in the best interest of your customers?

4 A (Witness Abramovitz) No, the purpose of the
5 Public Service Commission is to regulate a public utility, a
6 utility that is obligated to serve customers.

7 Q Right. But if the interests were aligned, then
8 there would never be any reason for them to review your
9 proposals. It would just be, well, whatever you're doing
10 must be in the best interest of consumers?

11 A (Witness Abramovitz) Oh, on the contrary. I
12 think these -- proceedings like this are absolutely valuable
13 for not only customers, the Commission and the company,
14 because it provides great transparency for how rates are set
15 and the vision of the company and also the Commission.

16 Q You don't think that part of the value of these
17 proceedings is to resolve differences between what might be
18 the company's interests and might be the interest of some of
19 their customers?

20 A (Witness Abramovitz) We can agree on that.

21 Q Okay. I'll move on. Thank you for your
22 responses.

23 I'm going to look now beginning on page 59 of
24 your testimony. And this discussion you have of a recent
25 tax legislation, it goes over to page 61 of your testimony,

1 but I'm going to start on page 59. The company provided --
2 sorry.

3 The Company provided a response to various
4 staff data requests which were included in the exhibit RS/RT
5 to the panel testimony for Mr. Smith and Mr. Trokey. And on
6 page 59, line 21, you referenced one of those responses,
7 which is Staff LA-5-14. Do you see that?

8 A Yes.

9 Q And that was one of the responses -- I'm sorry.

10 Has the company subsequently identified
11 additional tax credits beyond those that the company's
12 previously identified in those responses to discovery that
13 have been filed with this Commission?

14 A (Witness Abramovitz) So -- and I'll let
15 Ms. Adams jump in here as well. So in our testimony which
16 you said goes from 59 through, I guess all the way through
17 61, you know, we do -- we talk about the request of -- that
18 discovery requests on basically solar ITCs. We talk about
19 the benefit potentially of hydro modernization and then we
20 also talk about what we see is, unfortunately, not a benefit
21 gained from our existing nuclear facilities.

22 So I don't know the exact response in the data
23 requests here, but I can say that we're continually looking
24 and as we find other avenues to take advantage of federal
25 incentives for our customers, we'll make sure the customers

1 get it.

2 A (Witness Adams) And I'll just add that the
3 additional benefits that we identified since we submitted
4 that data request response were related to the hydro
5 modernization efforts. And there are -- as we included in
6 our testimony on page 61 -- approximately \$3 million of tax
7 benefits for this 3-year ARP.

8 Q The bottom of page 59, lines 25 and 26, you say
9 the company fully intends to pass any tax benefits related
10 to the IRA and the IIJA on to customers. And earlier in the
11 question you spell those out, the Inflation Reduction Act
12 and the Infrastructure and Investment Jobs Act; is that
13 correct?

14 A (Witness Abramovitz) That's correct.

15 Q If additional tax credits or other tax benefits
16 are realized by the company and the impact of those tax
17 benefits results in earnings within an earnings band, how
18 will the company pass on those tax benefits to customers?

19 A (Witness Robinson) It shouldn't have any
20 impacts to our earnings, if you will. Our proposal here is
21 to ensure that if we have to delay in passing those benefits
22 back, that those benefits are accrued in a regulatory
23 liability, and wouldn't affect our bottom line, if you will.
24 I would, of course, with this Commission's guidance, the
25 faster we can get benefits back to customers to lower the

1 cost of our service, the better.

2 Q Thank you.

3 Sorry for the pause. I think that I have a few
4 more questions. Could you refer to your testimony -- I'm
5 sorry to be jumping around now -- but page 38, and I'm going
6 to direct you to lines 7 through 9 on page 38.

7 A (Witness Abramovitz) Okay.

8 Q All right. Here you say staff incorrectly
9 applies Dr. Kaufman's proposed depreciation rates for
10 transmission distribution and general plant easements to the
11 appropriate plant and service balances. Do you see that?

12 A (Witness Adams) I do.

13 Q Okay. The rates provided by Dr. Kaufman were
14 applied to the plant balances that were provided by the
15 company to staff in response to discovery. Is that your
16 understanding?

17 A (Witness Adams) They did. Unfortunately, the
18 rate that they used included a depreciation rate associated
19 with easements, which have longer lives than the underlying
20 assets that are included there. So when they included that
21 combined rate, they only applied it to the core underlying
22 assets and not the easements. And so it had the effect of
23 increasing their reduction and depreciation expense beyond
24 what would have been calculated.

25 Q Your rebuttal testimony doesn't quantify the

1 alleged corrections, does it?

2 A (Witness Adams) That's correct. The
3 application would have been 4 to \$5 million depending on
4 which calendar year you're looking at.

5 Q I'll move on now to discuss the average of
6 historical costs, and this is testimony of yours on page 23,
7 yeah, 23 and 24, I believe.

8 You criticize Mr. Mugrace's use of 2020 and
9 2021 for expenses because you say that they were affected by
10 COVID. Even though the calendar year is 2020 and 2021 were
11 impacted by the pandemic, the company was still required to
12 provide safe and reliable utility service during that time
13 period; correct?

14 A (Witness Abramovitz) That's correct.

15 Q And would you -- would you accept that the
16 company's O&M expenses, less production, for the 2020 and
17 2021 years did not decline from 2019?

18 A (Witness Adams) Would you repeat the question?

19 Q Sure.

20 I'm asking you to compare from -- and I have an
21 exhibit I can walk you through if you think it would be
22 easier to look at the numbers.

23 A (Witness Abramovitz) That may be better.

24 Q Okay.

25 MR. WALSH: Madam Chairman, I'm just going to

1 label this exhibit, and consistent with your
2 direction, I'm going to ask that two exhibits be
3 distributed now. I can't promise that I won't have
4 to show the witnesses something else, I just don't
5 know -- I think they will know the answers to the
6 rest of the stuff they will send, but I'm not sure.

7 MADAM CHAIR PRIDEMORE: So moved, so marked.
8 Mr. Thomas, go and do.

9 MR. WALSH: This is 114 for the court reporter.
10 Madam Chair, staff would like to mark for
11 identification as Staff's Exhibit 114 the attachment
12 to the company's response to STF-PIA-7-1.

13 MADAM CHAIR PRIDEMORE: So marked.

14 MR. WALSH: And staff would like to mark for
15 identification as Staff Exhibit 115, attachment B to
16 the company's response to Staff-LA-2-73.

17 MADAM CHAIR PRIDEMORE: So marked.

18 MR. WALSH: Thank you.

19 (The documents referred to were marked for
20 identification as Staff's Exhibits 114 and 115.)

21 BY MR. WALSH:

22 Q So what I'm going to ask you to do here -- or
23 what I'm asking you to compare, each of these exhibits is
24 two pages for calendar years 2018 through 2021, and then the
25 12 months ending June 30, 2022. And what I'm asking you to

1 compare is if you look on the second page of each year's
2 data, and you look at total O&M, the last number over.
3 Okay?

4 A (Witness Abramovitz) So Just to make sure
5 we're looking at the same thing, for example, page 2 of your
6 exhibit, you want us to look at line 139, the first number
7 there, which is 4 point -- rounding \$4.6 billion?

8 Q Actually, I'm looking at the far number.

9 A (Witness Abramovitz) Okay.

10 Q Which is for the retail.

11 A (Witness Abramovitz) Okay. So 4.4?

12 Q Yes.

13 And then, you understand Mr. Mugrace didn't
14 make any recommended changes to production?

15 A (Witness Abramovitz) Yes.

16 Q Okay. So to get to what we were saying is, you
17 would have to subtract the line 70 on the first page of that
18 exhibit, okay, to -- for the retail production -- total
19 production, and that's the dollar value that I'm looking
20 for, I'm considering for each year.

21 A (Witness Abramovitz) Okay.

22 Q And I can take you through the exhibits or I
23 can ask you to accept my math, subject to check, but the
24 main point is that if you did that math for 2018, 2019,
25 2020, and 2021, you would not see a reduction from 2019 to

1 2020 or 2021; that that figure that you get from doing that
2 calculation is greater for 2020 and 2021 than it is for
3 2019?

4 A (Witness Abramovitz) So, yes, I see that you
5 have singled out production O&M, but also left out T&D and
6 customer accounting, and marketing in this calculation, and
7 you're right, for those two years, it's roughly a billion
8 dollars, if you just do the difference.

9 Q Thank you.

10 On page 26 of your testimony you discuss
11 innovation center.

12 A (Witness Robinson) I'm sorry. Which page?

13 Q Page 26 of your testimony. The company's
14 energy innovation center. It's beginning on line 8. Do you
15 see that?

16 A (Witness Adams) Yes.

17 Q And you mention a number of things that the
18 innovation center platform can do. Have you quantified the
19 benefits for customers from the innovation center?

20 A (Witness Adams) So, first, the energy
21 innovation center has moved from a center, a physical
22 location. It's now virtual and encompasses many things that
23 are innovative in general, taking ideas to execution and
24 making improvements. So we haven't quantified those per se.
25 I don't have that information myself, but they have resulted

1 in increased safety, the ability to use unmanned aerial
2 vehicles to take a look at damage that may have occurred
3 from a storm. They've used it for bar coding in generation
4 facilities where they need to do tagging, so it's making
5 their jobs more efficient.

6 Mr. Robinson may be able to --

7 A (Witness Robinson) Yeah, over the years,
8 whether through the innovation center or through other
9 research and development activities, there have been ideas
10 that have been brought forward. One of those is advanced
11 distribution management system, which is an industry
12 standard today that was actually a research and development
13 project that was entered into between Southern Company and
14 the Department of Energy back about 12, 13 years ago, and
15 now ADMS, as it's referred to, is now an industry standard
16 that most utilities have employed.

17 Mrs. Adams referred to a UAS system, so
18 unmanned aerial systems. We are now transitioning the
19 inspection of our transmission lines to being done fully by
20 UASs, so a drone pilot would walk the right-of-way and do an
21 inspection, can get a lot closer to the insulators and the
22 equipment that's up, you know, 50, 60 feet in the air. So
23 that's just some examples of some of the things that have
24 come out of innovation center and our R&D efforts in
25 general.

1 Q But, Ms. Adams, did I understand you to say
2 that the company has not quantified the benefits from that
3 center?

4 A (Witness Adams) It's possible that the company
5 does. I don't have those with me.

6 Q Has the company --

7 MADAM CHAIR PRIDEMORE: Mr. Walsh, I would say,
8 though, it's widely known in the industry right now
9 that the use of drones in replacement of line walking
10 and having linemen climb and -- it's an accepted fact
11 that there's not only cost efficiencies but also
12 timing and safety efficiencies. I think that's a
13 given.

14 MR. WALSH: And my question is just because
15 this is a rate case to know if there was -- if they
16 had presented any --

17 MADAM CHAIR PRIDEMORE: Understood. She
18 answered you. Yeah. She just doesn't have it.

19 A (Witness Robinson) And the UAS idea was an
20 idea that was brought forward by an employee through the
21 innovation center in those efforts.

22 BY MR. WALSH

23 Q On page 27 of your testimony, you discuss
24 service awards and recreation. Has the company provided
25 evidence anywhere in its filing that demonstrates that these

1 types of incentives have worked to keep employees with the
2 company?

3 A (Witness Abramovitz) I would say we have
4 several pages on our overall compensation program of
5 attracting and retaining the most talented employees for
6 Georgia Power Company in the state, and, yeah, service
7 awards is a piece of that compensation program.

8 A (Witness Adams) And as we stated in one of the
9 data request responses, the use of recreation was miscoded.
10 There were additional -- different expenses that were
11 included, their meals and travel, that should have been
12 included in a different FERC account, which was included in
13 that data request.

14 Q Thanks for that clarification.

15 Is it fair to say the company hasn't broken out
16 the specific value related to the service awards as far as
17 how effective they've specifically been at retaining
18 employees or if the company has presented that as part of
19 its case?

20 A (Witness Abramovitz) That's fair.

21 Q Thank you.

22 On page 28 of your testimony you discuss
23 community services, dues and experimental costs. Do these
24 costs represent utility-related services that reflect
25 provision of safe and reliable service?

1 A (Witness Abramovitz) I would say yes. When we
2 are members of associations and we provide community service
3 and even what's labeled here as experimental costs, yes, it
4 all goes into our obligation to continue to serve our
5 customers in the most effective way possible.

6 A (Witness Robinson) Especially, but as
7 association dues, through our participation through IEEE and
8 other industries, we have subject-matter experts that sit on
9 standards committees that develop standards that benefit not
10 just customers here in Georgia, but all throughout the
11 industry.

12 Q And is that the case for every community
13 service that you provide?

14 A (Witness Abramovitz) I was speaking
15 specifically to association dues, particularly around IEEE
16 and other trade associations that we reimburse employees for
17 participation in.

18 Q Okay. But for community -- are all of the
19 community services that you've sought recovery for in this
20 rate case, is it your testimony that all of them are related
21 to the provision of safe and reliable service?

22 A (Witness Abramovitz) Yes. And the more we can
23 understand the communities and the customers we serve, the
24 safe and more reliable our product will be.

25 COMMISSIONER MCDONALD: When you talk about

1 service awards, I'm jumping back to the last question
2 about service award. Is there a flip side to the
3 service award? When someone is not doing their job,
4 what happens there?

5 MR. ABRAMOVITZ: So, Commissioner McDonald, let
6 me be clear. A service award is time based. So, for
7 example, I've been with the company for a little over
8 21 years. I received a service award for longevity.
9 It incentivizes retention of our employees.

10 Of course, we obviously performance manage.
11 And if there are low performers, we either put them
12 on performance improvement plans, or, unfortunately,
13 some of them aren't with the company any longer.

14 So the longevity -- the service award is to
15 award longevity and superior performance by an
16 employee, but it's not to incentivize an employee to
17 stick around if they're not performing well.

18 COMMISSIONER MCDONALD: Who makes the
19 evaluation?

20 MR. ABRAMOVITZ: Each employee's manager.

21 COMMISSIONER MCDONALD: Who makes the
22 evaluation of -- up the line, at the top, starting at
23 the president down, who makes that evaluation?

24 MR. ABRAMOVITZ: You hit it. It starts with
25 the president down.

1 MADAM CHAIR PRIDEMORE: But wouldn't the board
2 of directors -- the board of directors oversees the
3 president's performance?

4 MR. ABRAMOVITZ: Sure, so our compensation
5 committee for our board does that as well. That's a
6 very good point.

7 COMMISSIONER MCDONALD: Thank you.

8 MR. ABRAMOVITZ: You're welcome.

9 BY MR. WALSH:

10 Q Now, I'll ask you to take a look at Staff
11 Exhibit 115 that was circulated earlier. It's the response
12 to Staff-LA-2-73, attachment B. As of May 2022, is it
13 correct that the company had 6,546 employees on the payroll?

14 A (Witness Abramovitz) Can you -- you faded out
15 for a second there.

16 Q I'm sorry.

17 A If you could repeat your question.

18 Q If you could look at the May 2022 column on the
19 top chart on the page. Do you see that?

20 A Yes.

21 Q Does that reflect -- sorry. Does that reflect
22 that as of May 2022 the company had 6,546 employees on the
23 payroll?

24 A (Witness Abramovitz) That is correct.

25 Q And then the next month, June 2022, that --

1 does that reflect that the company has 7,016 employees on
2 the payroll?

3 A (Witness Abramovitz) No. That is a labor head
4 count projection which is a way that we, a method that we
5 budget our labor resources. And while in May 2022 we had
6 roughly 6,500 employees on payroll, and in June 2022, we
7 expected to have 7,000, that's more of a financial budgeting
8 indicator of, okay, we have work that needs to be done by an
9 additional 500 people or individuals, how are we going to
10 complete that work?

11 And typically what we do to complete that work
12 instead of going to hire 500 people in a month, is the
13 existing 6,500 folks usually work overtime. We hire
14 additional contractors or sometimes we have to push work
15 out.

16 Q So you did not have -- do you currently have,
17 do you know -- have you currently yet reached that number of
18 7,016 employees?

19 A (Witness Abramovitz) I actually do not know.

20 A (Witness Adams) Part of the point is that in
21 managing the work that needs to be done, we have a balance
22 between actual employee head count and then also contractor
23 labor head count. And the 7,000 represents that combined
24 effort of projected need, recognizing that at any given time
25 we may not have -- we don't have that many employees on hand

1 because we're also using contractors.

2 A (Witness Robinson) And also understanding that
3 it also take times to bring employees up to speed to like
4 linemen and highly-skilled craft employees. And so there's
5 a period of time we need to offset those vacancies that we
6 have as we hire those classes, because it takes time to get
7 a class built up and bring them in. So we've got to manage
8 that, so we may bring in more contractors as we're waiting
9 for the next class to come on board. We do that with
10 operators as well.

11 Q Did your request for rate increase incorporate
12 the 7,016 employee number for June '22?

13 A (Witness Abramovitz) It did, because that is
14 the -- that is an input into -- I think what Ms. Adams and
15 Mr. Robinson is getting at is that is an estimate and input
16 into a labor cost or a labor O&M cost. So, like I said
17 before, while I may not have a Georgia Power employee making
18 up that 7,000 head count, I may have a contractor or an
19 existing employee working overtime. It still goes to the
20 total cost of labor to serve our customers.

21 Q So you hired more contractors between May '22
22 and June 2022?

23 A (Witness Abramovitz) It's possible that that's
24 how we're filing the labor need.

25 COMMISSIONER MCDONALD: When you talk about

1 that contractor, are you including like their
2 employees in that number like Pike Electric that if
3 they got a crew of 50 on a transmission job, is that
4 included in that 7,000?

5 MR. ROBINSON: No, Commissioner. I
6 specifically -- we're saying that it takes 7,000
7 FTEs, full-time employees, to get the work done. So
8 it may be that we are working to get a class of
9 linemen trained up, and we may offset that with Pike
10 linemen, as you mentioned. So we might bring a Pike
11 crew in, whether it's on distribution or
12 transmission, to fill that gap as we have -- linemen
13 are going through apprentice training to get up to
14 their journeyman status.

15 BY MR. WALSH:

16 Q So you said it's possible that you did. But
17 I'm trying to understand if the difference between May 2022
18 and June 2022 was reflected, if not in an increase in the
19 number of employees, was increased from one month to the
20 next by that equivalent in additional contractors and
21 additional overtime hours? That happened from the end of
22 May 2022 to the beginning of June 2022.

23 A (Witness Adams) It's really apples and
24 oranges. So the 6,500 is a count for employees, and the
25 7,000 is a count for the number of individuals, contract and

1 employees, and so there's not -- we probably had 7,000
2 individuals doing the job. The actual head count that you
3 requested, the 6,500, that's the number of employees only,
4 not the combined employees and labor to do the day-in and
5 day-out work.

6 A (Witness Robinson) And as Ms. Adams mentioned
7 before, we might have employees cover an additional shift or
8 work overtime, and so you would find those dollars to do
9 that work in another account looking at the overtime to pay
10 those employees.

11 Q On page 35 of your testimony, beginning at
12 line 22 -- I'm sorry -- yeah, around line 22, you say that
13 if financial incentives are not recovered from ratepayers,
14 employees will improve operational performance and customer
15 satisfaction regardless of the financial costs to do so.

16 Do you see that?

17 A (Witness Abramovitz) Let me read for the
18 entire context real quick.

19 Okay.

20 Q So is that a fair reading of your testimony?

21 A (Witness Abramovitz) Yes, it's what we've
22 written.

23 Q If financial incentives were still offered to
24 employees but recovered from shareholders instead of
25 ratepayers, then there wouldn't be any risk of that

1 happening which you identified in testimony; right?

2 A (Witness Abramovitz) So the risk is that -- it
3 is a departure for the company recovering its cost of
4 serve -- cost to serve. And I understand there may be
5 confusion, I think we talked about this earlier, of a
6 financial incentive not benefiting customers because it has
7 the word financial on it.

8 We are always incentivized to run our business
9 as effectively as possible. Sometimes what that leads to is
10 lower costs. Sometimes what that also leads to is us
11 earning above our ROE set point as allowed by the authorized
12 ROE band in our ARP. That is why the incentive is
13 appropriate.

14 Q Well, was the answer to my question yes or no?

15 A (Witness Abramovitz) I don't remember your
16 question.

17 Q If financial incentives were still offered to
18 employees but recovered from shareholders instead of
19 ratepayers, then there wouldn't be any risk of what you
20 described in this paragraph happening, would you agree with
21 that?

22 A (Witness Abramovitz) I'm not sure whether or
23 not that's a hypothetical situation.

24 Q Well, I mean, a difference in the case is
25 whether this type of incentive should be recovered from

1 ratepayers or recovered elsewhere. So I think it's a
2 relevant question.

3 I mean, you've identified a harm. You say if
4 we don't give you this recovery then this harm is going to
5 happen. And I'm suggesting, if you still provided the
6 incentive, the financial incentive, but you didn't have
7 ratepayers pay for it, you had shareholders pay for it,
8 would you still have the problem that you would be
9 encouraging employees to focus solely on operational
10 performance with no balance or accountability to costs,
11 causing employees to improve operational performance and
12 customer satisfaction regardless of financial cost to do so.
13 If they still had the financial incentive, that wouldn't be
14 problem; right?

15 A (Witness Abramovitz) They still have that
16 financial incentive. That wouldn't be a problem. The
17 question here and what's at issue here is that incentive is
18 part of our overall compensation plan for our employees. It
19 is a cost to serve our customers, whether it's labeled
20 operational performance or financial performance.

21 Q And I'm not looking to go back -- I'm sorry.
22 Did I cut you off?

23 A (Witness Abramovitz) (Indicating.)

24 Q I'm not looking to go back through that whole
25 debate. I understand your -- I think you understand the

1 task. What I was identifying was just this one specific
2 harm that you identified, and just to see if that particular
3 harm would be addressed other ways other than having
4 ratepayers pay for it.

5 I would like to now move on to some system
6 reliability questions.

7 On what types of substation equipment does the
8 company routinely conduct diagnostic tests?

9 A (Witness Robinson) So I believe we've
10 submitted that in data requests. We perform preventive
11 maintenance on substation transformers, on what we call
12 circuit breakers, on battery systems, on relay systems.
13 Pretty much anything inside the fence of a substation that
14 has functional movement. And we have a program, as I
15 mentioned, that's been submitted in our data requests as far
16 as the guidelines of those programs, and those are trade
17 secret. But those are the types of equipment that we
18 maintain on a regular basis.

19 Q How often does the company routinely test such
20 equipment?

21 A (Witness Robinson) Based on the type of
22 equipment. As I said, that's mentioned in our data
23 requests.

24 Q How about transformers, power transformers, as
25 an example. Would it be -- let me ask you, before I say

1 this. Is the frequency of testing power transformers, is
2 that a trade secret?

3 A (Witness Robinson) I don't believe that part
4 was trade secret.

5 Q Okay. So would it be fair to say --

6 A (Witness Robinson) The general programs
7 overall, I believe, were filed as trade secret.

8 Q Okay. Is it fair to say that the company tests
9 its power transformers on average about once every three to
10 five years?

11 A (Witness Robinson) It depends on the test. So
12 we have multiple different tests that we use on
13 transformers, transformer turn ratio tests, double test,
14 megger tests. We also do oil analysis. Oil analysis is
15 done on a more frequent basis. It's done on a six-month
16 basis.

17 Q How many power transformers does the company
18 operate?

19 A (Witness Robinson) Subject to check, I believe
20 it's 2,800.

21 Q 2,800?

22 MADAM CHAIR PRIDEMORE: May I ask you,
23 Mr. Walsh? What does this have to do with the rate
24 case? Do you have a question related to this? This
25 is very IRP focused in terms of planning and

1 strategic scope of how the company lays transmission.

2 MR. WALSH: Yes, Madam Chair. The company is
3 proposing a transmission investment plan which is a
4 substantial investment. As you know from the staff's
5 testimony in this case, staff believes that testing
6 is a -- diagnostic testing is an effective and more
7 economical approach than the substantial transmission
8 investment plan.

9 There were questions raised during both of the
10 earlier rounds of testimony about the efficacy of
11 diagnostic testing. And in order to understand how
12 significant the number of failed tests might be, you
13 know, a test where it didn't -- you did a diagnostic
14 test, the equipment passes the test, but then it
15 later fails. And there was -- there's been a number
16 discussed about how many of those failures there have
17 been. In order to understand whether that -- whether
18 tests are effective, you want to know how many times
19 do you do the tests and compare that to how many
20 failures, because if you do a whole bunch of tests,
21 and there's only a relative -- you know, that number
22 might be a very small percentage, and that's what I
23 was getting at.

24 MADAM CHAIR PRIDEMORE: Okay. Well, then,
25 perhaps let's ask that question then. Instead of

1 asking how many transformers are in the system, which
2 is a planning question, let's ask a question that's
3 relative to how many tests failed.

4 MR. WALSH: Well, I need to know how many
5 transformers there are and how often you test the
6 transformer to get to know how many times you do the
7 testing.

8 MADAM CHAIR PRIDEMORE: I'll allow it, but this
9 is -- we're down a deep rabbit hole that doesn't have
10 anything to do with the case. I'm sorry, Mr. Walsh.

11 MR. WALSH: I think -- let me go through and
12 see if I can ask the witness the next questions.

13 MADAM CHAIR PRIDEMORE: I mean, I'm sure --
14 these are experts and they want to talk about their
15 system, they're proud of their system, but this is --

16 MR. WALSH: I need to know how many times they
17 do the testing in order to determine, in order to
18 make what staff's point is what we think the testing
19 is efficient.

20 MADAM CHAIR PRIDEMORE: Then ask how many times
21 do you do the testing.

22 MR. WALSH: Well, I did ask how frequently they
23 test.

24 MADAM CHAIR PRIDEMORE: Right. But how many
25 times do you do the testing, and then you can back

1 the numbers out from that, perhaps.

2 MR. WALSH: Okay.

3 MADAM CHAIR PRIDEMORE: I'm asking you to move
4 it long.

5 MR. WALSH: I'm trying. Honestly, I'll try to
6 move it along.

7 MADAM CHAIR PRIDEMORE: Thank you, Mr. Walsh.

8 BY MR. WALSH

9 Q So over the past ten years if you use an
10 average of four years between tests on equipment, and your
11 discovery response says you have 2,264 power transformers,
12 so taking that number, if you were to test each of those --
13 on average, four -- every four years, you would come out
14 with about 5,660 tests?

15 MR. HEWITSON: Before you answer that, can I
16 understand where the four years came from? Because
17 when you asked how often you do a test, Mr. Robinson
18 responded it depends on what test. It could be
19 anywhere from every six months to every couple of
20 years. So I don't know where that four years is
21 coming from, so I would object to the predicate of
22 the question.

23 MR. WALSH: I can -- the four years was coming
24 from just a general average to see if that's a
25 reasonable average for a particular -- if it

1 varies -- I can ask just the question how many times
2 has the equipment been tested for power transformers.
3 Do you have a ballpark --

4 MR. HEWITSON: Which tests?

5 MR. WALSH: Any diagnostic test of power
6 transformers.

7 MR. HEWITSON: But I think Mr. Robinson as the
8 expert needs to know which tests he's talking about
9 so he can talk about how often it's done on which
10 type of equipment.

11 MR. WALSH: I'm talking about total tests, if
12 he knows.

13 MR. HEWITSON: Total tests?

14 MR. WALSH: I'm having a little bit of
15 difficulty.

16 COMMISSIONER MCDONALD: Mr. Robinson --

17 MR. WALSH: I tried to walk him through --

18 COMMISSIONER MCDONALD: -- would you describe
19 testing in brevity?

20 MR. ROBINSON: Yes, Commissioner. So we run a
21 multitude of tests on different equipment. It's
22 detailed in the documents that we provided. We're
23 running different types of tests looking at the
24 internal health of the equipment.

25 Mr. Walsh is talking specifically about power

1 transformers. There is a slate of about five to six
2 tests that we run on a routine basis. Some are six
3 months, some are two years, some are four years, as
4 Mr. Walsh mentioned, and some are six years.

5 COMMISSIONER MCDONALD: And what's the failure?

6 MR. ROBINSON: So the most effective test we
7 have looking at the internal health is the dissolved
8 gas analysis. That tells us that there's something
9 wrong inside the transformer. We're looking for
10 different gases, moisture. That raises a flag to say
11 we need to go to do additional tests, which is the
12 other tests that I mentioned.

13 The failure rate, as we mentioned in testimony
14 of those transformers that have failed in service
15 over the last 10 years, 55 percent of those
16 transformers passed their recent dissolved gas
17 analysis test.

18 And I would also say that we have been
19 deploying condition-based maintenance monitors on
20 transformers that give us a -- we call them a
21 smoke detector. They give us an idea that there's
22 smoke that we need to go investigate and take an
23 additional test to look at.

24 So those monitors are actually monitoring those
25 transformers on a 15-minute interval and reporting

1 back to the company, so we would know. So it's
2 almost impossible to answer Mr. Walsh's question as
3 far as interval testing.

4 BY MR. WALSH:

5 Q In rebuttal, you report that the company
6 replaced 196 transformers over the last ten years, and
7 including 108 that failed despite passing their diagnostic
8 tests. Is that your testimony?

9 A (Witness Robinson) That's -- those are the
10 transformers I just mentioned to Commissioner McDonald.

11 Q Is it fair to say -- you mentioned the most
12 effective test in your response. Do you recall the name for
13 that?

14 A (Witness Robinson) The DGA, dissolved gas
15 analysis test?

16 Q Yes. How often do you do that test?

17 A (Witness Robinson) We do those every six
18 months, sometimes every three months, depending on the type
19 of transformer.

20 Q And how often --

21 A (Witness Robinson) As I mentioned before, the
22 Hydran units that we have, the condition-based maintenance
23 that we've been deploying, do a more routine test to let us
24 know that there's something wrong inside the transformer.
25 It doesn't give us which test. It doesn't tell us that

1 acetylene is high or moisture is high, but it allows us to
2 alarm our maintenance crews to go out and take additional
3 tests on those transformers.

4 Q Okay. So for the DGA test, which you've
5 identified as the most effective test --

6 A (Witness Robinson) It's the most overall
7 effective test to tell us that there may be something going
8 on inside the transformer. The transformer is a big steel
9 box. We cannot see inside, and we're looking at the health
10 of the windings, the oil, everything that makes that
11 transformer run. And so the dissolved gas analysis test is
12 the most overall effective test for determining whether
13 there's an issue that we need to address.

14 Q And so you -- do you do that test on all
15 transformers?

16 A (Witness Robinson) All power transformers that
17 we have the -- and I believe that's the 2,200 that you
18 mentioned. Power transformers as a whole, I believe, is
19 closer to 2,800. We have pad-mount transformers and
20 pole-mount transformers that are in that classification that
21 we don't necessarily do those tests.

22 Those are more like distribution-type
23 transformers. I'm talking about specifically the big gray
24 boxes inside substations that you see on the side of the
25 road, and, yes, we perform those tests on a routine basis

1 with those transformers.

2 Q So over the ten-year period, you would have
3 tested -- run that test thousands of times?

4 A Millions, if you include the Hydran units.

5 Q Okay. And you identified the 108 of the
6 overall times where something tested, where the test did not
7 identify a failure and then it failed -- that that piece of
8 equipment, a transformer, substation transformer, passed the
9 diagnostic and then ended up failing?

10 A (Witness Robinson) I'm sorry. I got lost in
11 your question. Can you repeat that?

12 Q You identified 108 substation transformers that
13 failed after passing diagnostic tests and inspections;
14 correct?

15 A (Witness Robinson) Yes, that's correct, the
16 most recent tests.

17 Q But you have done -- you have done, as you
18 said, of the DGA, I think you said millions in the last ten
19 years, and other tests as well over the last ten years;
20 correct?

21 A (Witness Robinson) That is correct.

22 Q Okay. So while there have been 108 failures,
23 there have been trem- -- I mean, there's been 108 instances
24 where it didn't detect the failure. The tests have been
25 productive and effective in a large percentage of the cases?

1 A (Witness Robinson) I would say that 55 percent
2 of transformers passing their most recent test and then
3 failing in service does not point to those tests being an
4 absolute on the health of the transformer.

5 Q Not an absolute, but they're effective?

6 A (Witness Abramovitz) 55 percent, I'm not
7 sure -- when you talk about getting towards the end of the
8 life of the asset, I would say that they're not as effective
9 as they are in midlife of the asset.

10 Q Georgia Power Company designs and operates
11 substations under an N-1 contingency approach; correct?

12 A (Witness Robinson) Not necessarily.

13 Q It does not? Does it always meet N-1 as a
14 minimum standard?

15 A (Witness Robinson) Not necessarily.

16 Q Okay.

17 A (Witness Robinson) Those are NERC requirements
18 that you're talking about that are for transmission assets
19 and transmission lines. Many substations -- and most of our
20 substations are not designed to N-1, they are load serving,
21 and when that transformer is out, the load is out.

22 Q N-1 is a form of resilience that ensures system
23 availability in the event of a component failure?

24 A For transmission network systems for 230kB and
25 above -- or 115 kB and above, I'm sorry, there are NERC

1 requirements that require us to do N-1, minus G, which is a
2 generator analysis. The analysis that you're speaking to is
3 not performed by distribution substations, which is a
4 majority of the assets in the transmission grid improvement
5 plan.

6 Q What percentage of the company's power
7 transformers, the 2,264 transformers, are backed by the N-1
8 contingency?

9 A (Witness Robinson) By the N-1?

10 Q Yes.

11 A (Witness Robinson) Distribution substations or
12 transmission substations?

13 Q Well, let me ask you. The --

14 A (Witness Robinson) So we --

15 Q -- power transformers that were identified in
16 the response to staff WG1-33. Would it help you to take a
17 look at the response?

18 A (Witness Robinson) Sure.

19 MR. WALSH: Madam Chair, may I approach?

20 MADAM CHAIR PRIDEMORE: You may approach.

21 I still don't understand, Mr. Walsh. This is
22 detailed transmission planning that was covered in
23 the IRP.

24 MR. WALSH: Madam Chairman, in order to do --
25 for the Commission to evaluate --

1 MADAM CHAIR PRIDEMORE: But asking him
2 selections on the number of transformers that are
3 under NERC review, of course, utilities are going to
4 follow NERC review. That's a strategic planning
5 question.

6 MR. WALSH: He testified that not all --

7 MADAM CHAIR PRIDEMORE: If the Commission and
8 staff doesn't believe that they're being genuine or
9 truthful about the amount of transmission needs, then
10 just ask those questions.

11 MR. WALSH: Madam Chair, in order for the
12 Commission to evaluate whether the transmission
13 investment plan and the grid investment plan are
14 cost-effective options moving forward, the staff
15 believes that you have to look at what alternatives
16 there are, and part of the alternatives is looking at
17 what system reliability looks like without that
18 transmission investment plan and other measures they
19 can take.

20 And I know those sound like system planning
21 tests, but in order to identify whether what they're
22 proposing is cost effective, you have to look at
23 whether what they're doing now is cost effective and
24 what are the risks to this system today without the
25 transmission investment.

1 MADAM CHAIR PRIDEMORE: But the transmission
2 plan was approved in the IRP. Maybe it's the level
3 of recovery that you don't want to see the company to
4 be able to recover on transmission.

5 What I'm saying is, we're going go down a deep
6 hole on transmission planning that is not exemplified
7 in rates in any way. I'm just asking you to please
8 center your questions around rates and around the
9 case. That's all.

10 MR. WALSH: Okay.

11 MADAM CHAIR PRIDEMORE: And, likewise, I'm
12 asking the company to please just succinctly answer
13 the question. You guys are very knowledgeable. I
14 understand that, but...

15 A (Witness Robinson) Can you repeat your
16 question --

17 BY MR. WALSH

18 Q Yes. What percentage --

19 A (Witness Robinson) -- as it relates to this --

20 Q -- of the company's 2,264 transformers are
21 backed by the N-1 contingency? And I'm referring to the
22 transformer -- the number --

23 A (Witness Robinson) Right.

24 Q -- on that --

25 A (Witness Robinson) Response A --

1 Q -- yes, thank you.

2 A (Witness Robinson) 2,264.

3 So of those 2,264, there was another data
4 request that was submitted. Of those, about 400 or so are
5 actually transmission substations or transmission
6 transformers. Those are planned N-1 criteria. So if you
7 take that 400 out of that 22, that's 1,800. So about 1,800
8 of these transformers are not planned N-1 criteria.

9 Q Of the 108 instances in which a transformer
10 failed despite passing its diagnostic test, how many of
11 these did not result in a service interruption?

12 A (Witness Robinson) I would say very few.

13 Q Okay. Thank you.

14 A (Witness Robinson) Very few resulted in --
15 very few did not -- repeat your question. I'm sorry.

16 Q Sure. Of the 108 instances in which a
17 transformer failed despite passing diagnostic tests, did all
18 of those result in service interruptions?

19 A (Witness Robinson) I would say most of them
20 resulted in service interruptions.

21 Q Were those limited service interruptions?

22 A (Witness Robinson) There was one that failed
23 on the east part of town back in 2017 time frame that had
24 load out for about three days.

25 MR. ABRAMOVITZ: In east part of Atlanta?

1 MR. ROBINSON: Oh, what did I say? East part
2 of Atlanta.

3 MR. ABRAMOVITZ: You said town.

4 MR. ROBINSON: Oh, town, Atlanta, this town.

5 BY MR. WALSH:

6 Q Okay. Were there more that resulted in
7 extended or just the one?

8 A (Witness Robinson) Oh, there were multiple
9 that resulted in extended -- particularly when you have a
10 catastrophic failure of a transformer and that transformer
11 is the single source for load and you have no ability to
12 pick that load up in the field, there are extended outages
13 that occur from those.

14 There are tie points with distribution feeders
15 where we can, but those not necessarily automatic. Those
16 have to be planned for, looked at the load and shifted, and
17 done in the field sometimes manually.

18 Q Your rebuttal states that if the replacements
19 are not undertaken system reliability will be negatively
20 impacted. Has the company presented as part of its case any
21 estimate of the degree to which system reliability will be
22 negatively impacted?

23 A (Witness Robinson) No, and as I testified in
24 direct, it would be impossible to predict that. There's so
25 many unknowns in the transmission system. It's a network

1 system, and there are so many different parameters to take
2 into consideration, the type of failure, whether it's
3 controlled or catastrophic, the effect of generation,
4 whether you have to redispatch generation because of that
5 outage, the impact to customers, the cost to customers.
6 Those -- all of those things to consider would make it
7 impossible to predict that.

8 Q Let me explore that for a second. For a
9 cost-benefit analysis of the transmission investment plan,
10 you could take a variety of situations into consideration in
11 coming up with a range of different outcomes based on
12 historical experience as to how much equipment might fail
13 after passing a diagnostic test. And then you could create
14 a similar range of outcomes given N-1 redundancy on what
15 percentage of such equipment failures would actually result
16 in an outage. And then you could identify a reasonable
17 point within that range of outcomes to assess any increased
18 outage time that would result from not implementing the
19 transmission investment plan. And you could assign a dollar
20 value per kilowatt hour of not being interrupted. And then
21 you could compare that to the cost of the transmission
22 investment plan. Those steps could have been taken; right?

23 A (Witness Robinson) No, they could not have. I
24 disagree with that. Because taking historical and looking
25 at future are two separate things. So you're taking

1 historical performance and trying to predict the future.

2 We have significant changes that are occurring
3 on our transmission system, particularly around renewables,
4 interconnecting solar facilities throughout the state that
5 make it impossible to predict what the impacts of
6 transmission failures would be on the future state.

7 We don't know when outages are going to occur.
8 Out past 18 months, we have very little visibility on
9 generation outages and transmission outages. All of those
10 things are things that you're asking to predict based on
11 historic. You could do it, it would be wrong.

12 Q Well, every time someone makes a projection
13 before this Commission about what's going to happen in the
14 next three years in a rate case, they're going to be wrong,
15 it's just a question whether it's reasonable; right?

16 A (Witness Robinson) You would be dead wrong.

17 Q If a business that did not have a captive
18 customer base chose to undergo this type of massive
19 investment plan without doing a cost benefit analysis, and
20 then the benefits did not match the cost, then that
21 business' customers would have the option of leaving that
22 business for one of its competitors; correct?

23 A (Witness Robinson) So I would go back to what
24 I mentioned in direct testimony. Transmission system
25 benefits not only Georgia Power customers but the EMCs,

1 municipalities, and Dalton utilities, as well as our
2 neighboring utilities. And the ITS participants, so that's
3 GTC, MEAG, and Dalton, on behalf of the EMCs and
4 municipalities, are supportive of our transmission
5 investment plan. We have to let those -- we have to approve
6 those projects and bring them into parity. They are
7 supportive and approve those projects. So I would disagree
8 with you. I would say that those utilities do support this
9 program.

10 A (Witness Abramovitz) And let me just add into
11 that real quick. Like we've talked about earlier today, we
12 have an obligation to serve our customers. We're a utility.
13 We have an obligation to operate, maintain, and invest in
14 our system to make sure it's reliable and resilient.

15 So I understand the premise of the question,
16 but this is the business we're in and we're in the business
17 of keeping the lights on for our customers.

18 A (Witness Robinson) And, also, Georgia Power is
19 positioned differently than any other utility in the United
20 States, because we made an investment in a transmission
21 system when we were the only transmission owner in the '50s,
22 '60s, and '70s, and Atlanta grew significantly during that
23 period of time.

24 In the mid '70s, we sold off part of our
25 generation assets, as well as our transmission assets to

1 GTC, MEAG, or Oglethorpe at the time. And we sold all shiny
2 new stuff. And so we have a large population of aging
3 assets that are now turning 50, 60, 70 years old that the
4 other ITS participants do not have, and other investor-owned
5 utilities, as you referenced, do not have across the United
6 States.

7 Q My question was really just to the value of a
8 cost benefit analysis. And so, again, my -- I won't -- my
9 question was just if a company that didn't have captive
10 customers decided to engage in a big investment project and
11 didn't do a cost benefit analysis and then it turned out
12 that the cost outweighed the benefits, then they would be in
13 danger of losing customers.

14 A (Witness Robinson) To my point of why the ITS
15 participants are accepting of this program. They understand
16 the risks. They know what we're doing. They have to allow
17 those investments into parity considerations. Each of us
18 have to own investment on the system equal to our load ratio
19 share. And so if it was not seen as a benefit by GTC, MEAG,
20 and the City of Dalton, they would not be supportive of the
21 program and allow those in parity, which is a financial
22 construct.

23 Q Your rebuttal states that replacing equipment
24 prior to it failing a diagnostic test can avoid higher
25 maintenance and replacement costs; is that correct?

1 A (Witness Robinson) We have seen that replacing
2 equipment in a controlled, planned manner ahead of failure
3 can save 2 to 13 times the cost of replacement. So we've
4 seen transformers that failed catastrophically damage
5 equipment around them that costs six and a half times the
6 cost of doing it in a planned manner. And even if it's not,
7 even if it's a controlled failure, you're having to work
8 overtime and bring crews in at night, process banks, move
9 equipment around, cancel other work, and so there are costs
10 to customers to not do those projects in a controlled and
11 planned manner.

12 Q Did the company include in its filing any
13 estimate of the potential reduction in annual maintenance
14 costs for implementing the grid investment plan?

15 A (Witness Robinson) So to answer that question,
16 you really have to go back to the preventive maintenance we
17 were talking about before. We do that on all assets. So
18 that's not going to change depending on whether we swap
19 assets out or not.

20 What we're avoiding is this exponential growth
21 of equipment on our system that was installed in the '50s,
22 '60s, and '70s, that's now turning 50, 60, 70 years old,
23 that we've got to replace or we're going to have a
24 reliability emergency in the state of Georgia.

25 Q And I understand your position, but was the

1 answer to your question -- the answer to my question, was
2 that yes or no?

3 A (Witness Robinson) The same maintenance is
4 going to be performed on those assets as the other assets.

5 Q So did the -- did the company include -- I'm
6 not trying to be fake, I just really -- I'm not sure I
7 understand your question as a yes or no yet. Did the
8 company include in its filing any estimate of the potential
9 reduction in annual maintenance costs from implementing a
10 grid investment plan?

11 A (Witness Robinson) There would be no O&M
12 savings because the same diagnostic tests are done on new
13 assets as well as old assets. The savings comes in those
14 replacement costs, the cost to customers, the cost of having
15 to reschedule generation to mobilize, demobilize crews.
16 Those are the costs that we are trying to avoid with this
17 program, and ultimately, avoid this reliability emergency
18 that we see coming with these aging assets.

19 MADAM CHAIR PRIDEMORE: So Mr. Robinson -- he
20 answered your question. Next question. He answered
21 the question, twice, so go on to your next question.

22 MR. WALSH: I honestly didn't understand the
23 answer the first time as to whether it was a yes or a
24 no.

25

1 BY MR. WALSH:

2 Q Did the Commission -- did the company include
3 in its filing any estimate of the potential reduction in the
4 annual replacement costs as a result of implementing the
5 grid investment plan.

6 A (Witness Robinson) We have included in our
7 testimony the cost of failure that we've seen, and I
8 mentioned before 2 to 13 times the cost. To come up with
9 the number that you're talking about, it goes back to the
10 answer to the question before, it is impossible to do.

11 Q If staff experts estimated that the circuit
12 hardening costs thousands of dollars for premise served and
13 that undergrounding costs tens of thousands of dollars for
14 premise served. Am I'm correct that your rebuttal testimony
15 did not challenge those estimates?

16 A (Witness Robinson) We don't necessarily need
17 to challenge those estimates. The program that we ran was
18 on a system level looking at the benefits for all customers,
19 spreading that cost to across all customers. All customers
20 benefit from reliability and reliability investment.

21 To take their argument, we would never earn
22 underground anything. And most of north Atlanta, you get
23 above Atlanta is underground, so their arguments don't hold
24 water.

25 Q But you didn't challenge their numbers?

1 A (Witness Robinson) I have nothing to challenge
2 their numbers with. But we do have a third of our customers
3 that are served with underground distribution.

4 Q Has Georgia Power completed or provided any
5 cost benefit analyses that indicate that the value of
6 reliability improvements some customers are likely to
7 receive from its proposed packages exceed the high cost per
8 premise?

9 A (Witness Robinson) We're not doing a
10 feeder-by-feeder analysis and a cost benefit analysis on
11 each feeder. We're doing an economic benefit analysis on
12 the program as a whole looking at all customers benefiting
13 from -- there are \$1.4 million customers that are fed off of
14 feeders that are in the third and fourth quartile. The
15 program is to look at the optimal investment point, bringing
16 all customers up to first quartile performance so everybody
17 gets to experience the same level of reliability across the
18 system.

19 Q And so in sum, your testimony is that you
20 didn't do the cost benefit analysis because you believe it's
21 impossible to do it?

22 A (Witness Robinson) That was on the
23 transmission portion of the program. You switched to
24 distribution.

25 Q I'm sorry if I crossed it up. I'll move on.

1 Your rebuttal states that staff systemically
2 underestimated investment benefits by not accurately
3 representing the costs to customers of foregoing BIL and
4 undergrounding. Could you explain what BIL is or just state
5 what that is?

6 A Basic insulating levels. So that's length of
7 cross arms, material we have in cross arms. It's basically
8 moving your energized parts out from the grounded parts.

9 Q Was one of your primary costs to customers in
10 your mind deteriorating reliability?

11 A (Witness Robinson) I'm sorry? Can you repeat
12 your question?

13 Q Is one of the primary costs to customers
14 deteriorating reliability?

15 A (Witness Robinson) That is the issue that we
16 are trying to address, is we have \$1.4 million customers
17 that are fed off of feeders that have deteriorating
18 reliability and have been deteriorating since 2013.

19 Q SAIDI is a measure of reliability; is that
20 correct?

21 A (Witness Selvidge) For duration, that's
22 correct.

23 Q S-A-I-D-I?

24 A S-A-I-D-I, correct.

25 Q Okay. Your rebuttal testimony states that in

1 the absence of these investments, the company would achieve
2 an end-state SAIDI of approximately 127 by 2031, essentially
3 equal to the program starting point SAIDI in 2019; is that
4 your testimony?

5 A (Witness Robinson) That is our testimony
6 saying if we adopted Mr. Alvarez's and Mr. Stephens'
7 recommendation to remove BIL and undergrounding from the
8 program that there would be a end-state SAIDI of essentially
9 the starting point. Now, that doesn't address and talk
10 about the 400 or so feeders that would not receive any
11 investment and would have a SAIDI that gets up to like 300
12 minutes per year for those customers that are fed off of
13 those feeders.

14 Q Do you understand that the IRP order in the
15 2022 IRP expressly preserves staff's right to challenge the
16 timing of transmission investment in this rate case?

17 A (Witness Robinson) Let me -- let me look
18 through the order. Can you point me where the order -- I've
19 got a copy of it.

20 Q It's paragraph 13.

21 A (Witness Robinson) Are you talking about the
22 stipulated agreement or the order?

23 Q The order.

24 A I don't have a copy that shows paragraph
25 numbers. Do you have a page number?

1 Q I don't have it with me. I think the order
2 speaks for itself. That's fine.

3 A (Witness Robinson) I believe that it is in the
4 stipulated agreement. I have that as well.

5 Q It may also -- may also be. I just had the
6 location in the order.

7 MADAM CHAIR PRIDEMORE: Do you have a copy for
8 the witness?

9 MR. WALSH: I don't. The order speaks for
10 itself, so I'll withdraw the question.

11 MADAM CHAIR PRIDEMORE: Thank you.

12 MR. WALSH: That concludes my cross, and I'll
13 ask that staff's exhibits be moved into evidence.

14 MADAM CHAIR PRIDEMORE: So moved.

15 (Staff Exhibits 114 and 115 were admitted into
16 evidence.)

17 MADAM CHAIR PRIDEMORE: Americans for
18 Affordable Clean Energy.

19 MR. GALLOWAY: I have some questions.

20 MADAM CHAIR PRIDEMORE: You may go ahead.

21 MR. GALLOWAY: Madam Chair, before I get
22 started, I would like to ask your permission to pass
23 out my exhibits.

24 MADAM CHAIR PRIDEMORE: Please go ahead.

25 MR. GALLOWAY: (Hands out documents.)

1 MADAM CHAIR PRIDEMORE: You're short one,
2 Mr. Galloway.

3 MR. GALLOWAY: I'm sorry?

4 MADAM CHAIR PRIDEMORE: You're short one.

5 MR. GALLOWAY: Thank you. I apologize.

6 CROSS-EXAMINATION

7 BY MR. GALLOWAY:

8 Q Good afternoon, Panel. Newton Galloway on
9 behalf of AACE.

10 THE PANEL: Good afternoon.

11 Q I have limited questions related to one issue,
12 and that is the EV charging, Community Charging program.

13 A (Witness Abramovitz) I'm having a little --

14 Q I said I have questions only on one topic,
15 that's EV charging, the Community Charging program. And
16 what I've done is provided all of the parties with the
17 exhibits that I will use and ask that you follow along
18 through those with me.

19 And for the court reporter, I've got those
20 marked for you to supplement that way everybody will be on
21 the same page. And I will leave it to the panel's
22 discretion as to who is best to answer the question.

23 A (Witness Abramovitz) Thank you.

24 Q In the panel's testimony on page 21, beginning
25 at line 16, the panel notes that Georgia Power will continue

1 to offer EV charging services as a provider of last resort
2 in underserved areas through the Community Charging program.

3 A (Witness Abramovitz) That's correct, and it's
4 consistent with a very lengthy discussion during the direct
5 hearings.

6 Q Okay. And what I want to do today is just
7 flesh out a little more material on that. If you would,
8 please, turn to AACE Exhibit -- what's been marked as AACE
9 Exhibit Number 21. This is the company's response to the
10 staff's data requests as STF-PIA-1-8. And if you would pull
11 that up and confirm that in that data request the company
12 was asked to identify each community charging site that had
13 been referred to in a previous electric transportation
14 presentation, along with construction, number of charging
15 capabilities and so forth. And this constitutes your
16 response to that data request; correct?

17 A (Witness Abramovitz) Yes.

18 Q And the data request included the material on
19 the attachment, 1-8, which is the almost microscopic Excel
20 spreadsheet grid that follows on the next page; that's
21 correct?

22 A (Witness Abramovitz) Correct.

23 Q And then, so the panel will know -- because I
24 had trouble reading it, the third page of the exhibit I have
25 enlarged, just the first left-hand columns, to identify the

1 chargers and locations.

2 A (Witness Abramovitz) Okay.

3 Q Okay? All right. Now, this identified your
4 community -- your responses identified each Community
5 Charging site as of July 2021; correct?

6 A That's right.

7 Q Okay. And at that point, according to the
8 grid, the company had deployed chargers at approximately 24
9 Community Charging locations as shown on the report?

10 A (Witness Abramovitz) That's the count, yes.

11 Q And that included approximately 49 chargers?

12 A (Witness Abramovitz) Yes.

13 Q Okay. And out of the 49 chargers, five were
14 level two; correct?

15 A (Witness Robinson) I'm trusting that you're
16 reading the exhibit correctly.

17 A (Witness Houston) The vast majority were fast
18 chargers, yes.

19 Q And that would mean out of the 49 chargers, the
20 remainder, which would be 44, were fast chargers; correct?

21 A (Witness Abramovitz) Yes.

22 Q Again, assuming my math is correct and I'm not
23 trying to trick --

24 A (Witness Abramovitz) Subject to check.

25 Q Now, each of these chargers was identified by

1 the company as a community charger; correct?

2 A (Witness Robinson) Yes.

3 Q And I would assume, then, that it -- each
4 charger, then, met the company's criteria as being deployed
5 as a carrier of last resort, or provider of last resort, in
6 an area where private enterprise would not go to deploy a
7 charger?

8 A (Witness Abramovitz) At the time I can assume
9 that's correct, at the time.

10 Q If you would, turn to Exhibit 22, and we
11 undertook to just get an idea of how the company was
12 applying the definition -- applying that definition. And
13 the first location -- you will note on the third page, I
14 have highlighted four locations in green, and the first
15 location is identified at 14205 Highway 17 in Lavonia,
16 Georgia; is that correct, the first one on the grid?

17 A (Witness Abramovitz) That is what your
18 exhibits says.

19 Q Okay. And, of course, I don't expect y'all to
20 be familiar with each one of these particular sites, but if
21 you would turn to AACE Exhibit 22, and this was pulled from
22 a PlugShare website which identifies where chargers are
23 located, and it identifies a charger at 14205 Highway 17 in
24 Lavonia; correct?

25 A (Witness Abramovitz) According to

1 Plugshare.com. That's correct.

2 Q And to put that in perspective, that is located
3 at the I-85 interchange with Georgia 17, according to the
4 PlugShare map?

5 A (Witness Abramovitz) That's right. It looks
6 like it's right off an exit ramp.

7 Q Okay. And I would -- I don't know what
8 constitutes a typical interchange, but this looks like a
9 standard interchange where you have fast food, gas stations,
10 car repair, and so forth around it?

11 A (Witness Abramovitz) Yep. There's even a
12 hotel.

13 Q Okay. If you would, then, turn to Exhibit 23,
14 please, sir. And this is the second charger, which is
15 located at 2478 North Columbia Street in Milledgeville. And
16 assuming PlugShare is accurate, this would be, at least to
17 your and our communal knowledge based upon PlugShare's
18 accuracy, this would identify the area around that charger;
19 correct?

20 A (Witness Abramovitz) Correct.

21 Q And this was deployed next to the Milledgeville
22 Mall. Do you see that down at the bottom of the page?

23 A (Witness Abramovitz) I do. There's a TJ Maxx
24 and a Starbucks. It looks like a mall.

25 Q And then I would like to -- one more -- and

1 that's AACE Exhibit 24, and this is a charger location at
2 1514 Bradley Park Drive in Columbus. If you can -- again,
3 we are all dependent on the PlugShare data, but this
4 identifies 1514 Bradley Park Drive in Columbus, and that's
5 near a cloverleaf interchange on US-80 in Columbus; correct?

6 A (Witness Abramovitz) Yeah. We're just
7 checking and making sure it's on the list in the data
8 request response.

9 Q Okay. It is. It's number 3.

10 A (Witness Abramovitz) Okay.

11 Q It's number 3.

12 A (Witness Abramovitz) That may help us expedite
13 this a little bit.

14 Q Okay. But bottom line, this also is in a
15 commercial area around a major highway interchange?

16 A (Witness Abramovitz) Sure.

17 Q Now -- and I hate to put y'all back to the
18 micro script grid, but if you could flip back to the second
19 page. In response to staff's data request, you identified
20 usage and revenue of these chargers that are identified.
21 The usage is identified in energy per megawatt hour or in
22 megawatt hours for 2020, 2021, and year-to-date through
23 March of 2022; correct?

24 A (Witness Abramovitz) That's correct. That's
25 the last three columns of the exhibit.

1 Q Of the -- of the grid.

2 And you identify for those same years total
3 revenue for those chargers; correct?

4 A (Witness Abramovitz) Yes, we do.

5 Q Now, who made the decision that these chargers
6 should be deployed as part of the provider-of-last-resort
7 responsibilities of Georgia Power?

8 A (Witness Abramovitz) Our electric
9 transportation group and our customer service and solutions
10 team.

11 Q Okay. Y'all were not involved --

12 A (Witness Adams) I was just going to add that
13 this was in 2020.

14 Q Right. Right. I know it's got a little bit of
15 age on it, but it was the last data that was in the staff
16 data request responses.

17 But none of the panel was responsible for
18 making that decision?

19 A (Witness Robinson) No.

20 A (Witness Houston) No.

21 Q And you were also -- the four of you were also
22 not involved in making a decision as to whether a private
23 provider would be willing to go and serve at these
24 locations; correct?

25 A (Witness Robinson) No, but I can trust that

1 our team followed the appropriate guidelines to make these
2 decisions.

3 Q Okay. Well, let's follow up on that a little
4 bit, Mr. Abramovitz. Where are those guidelines?

5 A (Witness Robinson) I think we went over those
6 guidelines last time on the direct hearings.

7 Q Can you refresh my memory on what they would
8 have looked at?

9 A (Witness Robinson) I think you actually handed
10 this group an exhibit.

11 Q All right. Well, let's move forward and let's
12 look and see -- let's look at the performance that we have
13 here. For 2022, total megawatt hours from this list of
14 chargers I calculated to be approximately 77.59 megawatt
15 hours.

16 A (Witness Abramovitz) We'll trust your math.

17 Q Again, I'm doing the math, and I'm assuming my
18 calculator was correct, okay. And the total year-to-date
19 revenue from the chargers I calculated to be \$20,699.

20 A (Witness Robinson) Subject to check.

21 Q Okay. Now, the average charger -- this also
22 identifies the cost of capital investment for the charger.
23 That could include both the charger itself and also upgrades
24 to be able to get the service to the charger; correct?

25 A (Witness Houston) That's correct.

1 Q Okay. Now, this is ballpark, but it looks like
2 the cost is running about \$70,000 a charger.

3 A (Witness Robinson) We're going to have to
4 check -- We're going to have to trust your math.

5 Q Well, that's an estimate. I didn't do the
6 average. That's an estimate.

7 All right. So the revenue year-to-date for
8 these chargers comes in, and it varies, but looking at it on
9 average, taking \$20,699 and dividing it by the number of
10 chargers to about \$425 per charger year-to-date through
11 March of 2022.

12 A (Witness Abramovitz) Subject to check.

13 Q Okay. All right. If you would, turn back to
14 Exhibit 22, please, sir.

15 A (Witness Abramovitz) This is 14205 Highway 17?

16 Q Yes, sir, Lavonia.

17 All right. And if I look at the data on this
18 grid for the energy that it provided to EVs in 2021, that
19 charger provided 15 megawatt hours; correct?

20 A (Witness Adams) You're back on Exhibit 21 now?

21 Q Yes, Exhibit 21, yes, ma'am.

22 A (Witness Abramovitz) Yep, and in 2020 it was
23 4.27, and in 2022 year-to-date it was -- I'll round up, 3.

24 Q I was surprised it declined. I had expected
25 that one to have increased in 2022.

1 And that coordinates with the revenue in
2 2021 of -- I'm sorry. I'm sorry. Not revenue. This
3 charger had -- the 15 megawatts -- the 15 megawatt hours in
4 2021 equates to 1.2 megawatt hours per month, doing the
5 math.

6 A (Witness Abramovitz) Okay.

7 Q Okay. Now, looking at the grid, can you
8 confirm that the charger located at that location had the
9 highest revenue of any of these chargers in 2021 at \$7,312?

10 A (Witness Abramovitz) In 2021?

11 Q Yes, sir.

12 A (Witness Abramovitz) It also had the highest
13 usage.

14 Q That was my next question. It had both the
15 highest usage, which was 15 megawatts -- megawatt hours, and
16 that generated a total revenue of \$7,312 for that charger;
17 correct?

18 A (Witness Abramovitz) Yes.

19 Q And, again, doing the math, the \$7,300 for that
20 charger in 2021 would equal roughly \$610 of revenue per
21 month?

22 A (Witness Abramovitz) If everybody -- if the
23 charger was used on a routable basis each month, that would
24 be correct.

25 Q Okay. Now, the company has data on the amount

1 of megawatt hours used on virtually every charger in its
2 territory, does it not, pursuant to its contracts with
3 customers?

4 A (Witness Abramovitz) I believe that's correct.

5 Q And based upon this, even though these chargers
6 were located at or near interchanges and around shopping
7 centers, they are still not financially self-sufficient
8 today, are they?

9 A (Witness Abramovitz) I think that's the whole
10 concept of community charging. There's not a market,
11 charging the charge of last resort.

12 Q And we've got to get to a point,
13 Mr. Abramovitz, where there's a critical mass of those
14 chargers to make everything work economically for the
15 deployment of the charger for it to be viable?

16 A (Witness Abramovitz) For others that want to
17 enter that market, you're correct, but that's not what
18 Georgia Power's mission here is.

19 A (Witness Houston) I would also add that that's
20 reflective in the size of the program where we proposed
21 whether 10 to 11 new sites each year, and then increase the
22 cost is just a reflection of inflation and component costs
23 since the last time we were in front of the Commission.

24 Q Let me ask you one final question. Without
25 specific criteria to define them, isn't the market at a

1 point right now where virtually any location could
2 potentially qualify as a carrier of last resort charger
3 location until the market develops further?

4 A (Witness Robinson) No, I don't think we can
5 talk in absolutes like that.

6 Q Okay. Can we talk in almost absolutes?

7 A (Witness Robinson) No, I don't think we can.

8 Q Okay. But we agree there's got to be
9 advancement in the number of EVs on the road, coupled with
10 increase in the number of chargers for both the drivers to
11 feel safe driving the EV and for people to be able to deploy
12 and make money off the charger?

13 A (Witness Abramovitz) Sure. And like we've
14 talked about in this proceeding at length, and we expect a
15 higher option of electric transportation across the state,
16 talked about bus depots and whatnot. We see it coming.
17 We're trying to get prepared for it, but our role here in
18 developing that electric transportation ecosystem is to make
19 sure that we can serve the load not provide chargers at
20 every corner.

21 A (Witness Houston) And, also, I'll just say in
22 2020, 80 percent of our charging locations are outside the
23 plant, so we're looking to alleviate that charging as a
24 concept.

25 Q Would there have been no expectation that at

1 these locations we've identified in the community charging
2 program that private enterprise could come in and deploy at
3 those locations at interchanges and major shopping centers?

4 A (Witness Abramovitz) At the time I guess not
5 following our guidelines. I would say now that we have
6 great resources like Plugshare.com, maybe a private
7 enterprise will come in and add to the infrastructure we put
8 in place.

9 A (Witness Houston) I will just say on these
10 examples that you're showing us that took place in 2020, is
11 probably a long lead time to get these permanent and built
12 out. And the decisions were made, you know, prior to 2019.
13 So we've had some Community Charging stations prior to 2019,
14 very limited number, but that's probably why you pull out of
15 these very rare exemptions that shows similar charges in the
16 same geographic locations.

17 Q I will tell you, just so the Commission knows,
18 we looked at each one, and I just picked four because they
19 seem to be typical. I wasn't trying to skew the --

20 A (Witness Houston) They also happened to be the
21 earliest ones as well. As we continue to administer the
22 plan currently, we look at provider of last resort and the
23 criteria including geographic location, accessibility, and
24 safety. So the plan continues, and if you call out four
25 earlier examples, if you might find cross-pollinization of

1 others, but in general, that's not the way we're
2 administering the plan.

3 Q Ultimately, that means, though, as the company
4 gets more and more information related to the chargers and
5 related to how they're being used and where, we will have a
6 better assessment of where the chargers can be handled by
7 private enterprise and how to define a community charger.
8 Would you agree with that?

9 A (Witness Abramovitz) I would say the more
10 information that we get as a state, the more we can
11 appropriately deploy public transportation.

12 MR. GALLOWAY: Madam Chair --

13 COMMISSIONER MCDONALD: Back when Georgia Power
14 accepted the Commission's investment in solar energy
15 in 2013, how much ratepayer money was in that
16 investment?

17 MR. ABRAMOVITZ: Commissioner, I can't recall.

18 COMMISSIONER MCDONALD: Was the program
19 subsidized by the power company?

20 MR. ABRAMOVITZ: It was subsidized across
21 ratepayers, I believe.

22 COMMISSIONER MCDONALD: To what extent?

23 MR. ABRAMOVITZ: I'm not sure.

24 COMMISSIONER MCDONALD: When you say it was
25 across the ratepayers, was there -- was it -- was

1 there an amount put on their utility bill that
2 supported solar, utility-scale solar?

3 MR. ABRAMOVITZ: Yes. I'm not sure how much
4 there was, but that's -- that cost to service spreads
5 the cost across all customers, especially if we are
6 talking about a subsidization of a program like
7 Community Charging. It's similar. It's to start the
8 advent of finding the right resources and the right,
9 if you will, avenues to serve customers.

10 COMMISSIONER MCDONALD: I just was out there
11 Sunday. I just don't see how this -- when you looked
12 at the mass of automobiles that were out there Sunday
13 afternoon, it's -- it's above me, I'll say that.
14 It's above me.

15 Tim, you're going to have to explain it to me
16 someday.

17 VICE CHAIRMAN ECHOLS: Where on Sunday was
18 this, Commissioner?

19 COMMISSIONER MCDONALD: From St. Simons Island
20 to Cumming, Georgia.

21 VICE CHAIRMAN ECHOLS: Now, that Lavonia
22 charger they put critical. It's up there right on
23 the state line. There's nothing near it. Made it
24 virtually impossible to get into South Carolina
25 without that thing. It was -- it was a desert, and

1 it gets a lot of use because it is an oasis in the
2 middle of nowhere. Everybody that doesn't have a
3 Tesla has to stop there.

4 MR. GALLOWAY: Madam Chair, I would like thank
5 the panel for their time and response to questions.
6 That concludes my questions.

7 I would like to tender Exhibits AACE 21, 22, 23
8 and 24 into the record, and I will withdraw number
9 25, because we didn't need it. Thank you, ma'am.

10 MADAM CHAIR PRIDEMORE: So marked, so moved.

11 (AACE Exhibits 21, 22, 23 and 24 were admitted
12 into evidence.)

13 MADAM CHAIR PRIDEMORE: ChargePoint.

14 MR. FYKES: No questions.

15 MADAM CHAIR PRIDEMORE: Commercial Group?

16 MR. JENKINS: No questions.

17 MADAM CHAIR PRIDEMORE: Georgia Association of
18 Manufacturers.

19 MR. JONES: Very briefly.

20 CROSS-EXAMINATION

21 BY MR. JONES:

22 Q Madam Chair, Panel. Good afternoon. How are
23 you?

24 THE PANEL: Good afternoon.

25 MADAM CHAIR PRIDEMORE: Good afternoon.

1 Q Excellent.

2 I'll just get right to it. So the company
3 continues to argue that securitization is not needed.
4 Mr. Abramovitz should probably be the one to answer these
5 questions, but anybody on the panel is able to because the
6 Commission already has, in your words, all the tools
7 necessary that it needs to balance the needs of the
8 customers and the company. Is that your continuing
9 testimony?

10 A (Witness Abramovitz) That is a great summation
11 of our prefiled rebuttal testimony.

12 Q Well, I read it from page 21, so I think I must
13 have gotten it right.

14 Would you agree as part of the company's
15 opposition to securitization based on having to forego a
16 return on equity and certain of its assets?

17 A (Witness Abramovitz) The opposition is based
18 on what it actually costs to finance those expenditures and
19 the cost to finance those expenditures is not only with debt
20 but also with equity because that's our capital structure.

21 Q I noticed that in your testimony that you did
22 not take time to rebut staff's testimony or GAM's testimony
23 about the -- how this increase under this rate case, the
24 first 2023 rate increase from this case is the first of a
25 series of upcoming ones that has been talked about here and

1 Mr. Pollock referred to it as a perfect storm. I don't
2 believe you addressed that in your testimony, did you?

3 A (Witness Abramovitz) We didn't think it was
4 necessary because we did talk about it a lot in the direct
5 hearings.

6 Q Did you -- were you here when Mr. Pollock
7 testified or did you hear him testify?

8 A (Witness Abramovitz) I did hear him testify.

9 Q Did you hear his estimate of up to \$2.9 billion
10 in rate increases potentially over the next three years?

11 A (Witness Abramovitz) I don't recall that, but
12 subject to check, I'll trust --

13 Q That was his estimate?

14 A (Witness Abramovitz) -- that was his estimate.

15 Q Right. Do you have any reason to dispute that
16 estimate, or would you put a different number on it?

17 A (Witness Abramovitz) You know, so like we
18 talked about the direct hearings, I don't know what the
19 estimate of future rate increases is going to be because I
20 don't know how this Commission is going to rule on Vogtle
21 Units 3 and 4, and I'm not sure yet of what our
22 underrecovered fuel balance is going to be and what natural
23 gas prices are going to be in the future and what we're
24 going to need to set our fuel factor at, and we're going to
25 address all of that in February when we file our fuel case.

1 Q Sure. That's why you have to make estimates
2 because you don't know exactly what it's going to be.

3 Just really quick, they've already decided on
4 Vogtle 3, right, that's an increase that we know is coming
5 in?

6 A (Witness Robinson) That's correct. That was
7 last fall.

8 Q Just to clarify.

9 So wouldn't you agree that the prospect of
10 raising rates by 2.9 billion or somewhere in that area
11 should require the Commission to consider innovative
12 regulatory tools to moderate this impact on consumers?

13 A (Witness Abramovitz) I think any rate increase
14 or any series of potential increases should be in
15 consideration by this Commission and always is, and that's
16 why we have proceedings like this to make sure all of the
17 information is presented.

18 Q Sure. And you would further agree, wouldn't
19 you, that any resolution of this case, whether it's by
20 stipulation that's approved by the Commission or the
21 Commission's own decision outside of a stipulation should
22 consider those tools and consider the potentially
23 extraordinary impact on customers we might see over the next
24 three years; would you agree that that's something they
25 should consider?

1 A (Witness Abramovitz) I just want to be clear.
2 I'm not agreeing with this concept of innovative tools,
3 especially when the Commission has all the tools it has at
4 its disposal that's necessary.

5 Q So you don't think the Commission should
6 consider tools that you're suggesting, but maybe other ones,
7 too, that might be of benefit to consumers?

8 A (Witness Abramovitz) I think the Commission
9 has the authority and the jurisdiction to consider any tool
10 it deems necessary. I'm just making the argument that
11 securitization at this point isn't necessary.

12 MR. JONES: Thank you, Madam Chairman. That's
13 all I have.

14 MADAM CHAIR PRIDEMORE: Georgia Coalition of
15 Local Governments.

16 MS. BROWN: No questions.

17 MADAM CHAIR PRIDEMORE: Georgia Interfaith
18 Power & Light.

19 CROSS-EXAMINATION

20 BY MS. WHITFIELD:

21 Q Hello, Panel.

22 THE PANEL: Good afternoon.

23 Q In light of your comments about your
24 consideration of customers throughout this proceeding today,
25 would you agree that the financial impact to customers

1 should be considered by these Commissioners when they are
2 setting your ROE?

3 A (Witness Abramovitz) I think the financial
4 impacts to our customers like we've talked about today and
5 in the direct hearings, and all the factors in this rate
6 case, not just the return on equity, should be considered by
7 this Commission.

8 MS. WHITFIELD: No further questions.

9 MADAM CHAIR PRIDEMORE: GA Solar.

10 MR. MORELAND: No questions.

11 MADAM CHAIR PRIDEMORE: GASEIA.

12 CROSS-EXAMINATION

13 BY MR. THOMASSON:

14 Q Panel, just a few questions on the DER
15 management system that you propose, which starts on page 57
16 of your testimony. I'm going to sort of paraphrase a couple
17 of sentences. You testified that the DERMS needs to be
18 implemented in parallel with increasing DER penetration
19 because integrating DERMS is going to require a significant
20 amount of lead time to have that operational as DER
21 penetration increases; is that accurate?

22 A (Witness Robinson) There are certain systems
23 that we have to integrate with. There's the advanced
24 distribution management system, our SCADA system, customer
25 information system all have to be considered as far as

1 integration, as well as supporting programs that have been
2 approved by this Commission. The RDER pilot, consideration
3 of demand-side resources, along with supply, and future
4 RFPs, all of those are things to consider as it relates to
5 the time it takes to implement DERMS and to support those
6 things that I just mentioned in the future.

7 Q And the flip side of how much time it takes you
8 to integrate is that you're also looking, sort of skating to
9 where the puck is going, as to keep up with the DER
10 integration penetration levels?

11 A (Witness Robinson) We are as well as
12 distributed generation on our system with RFPs that have
13 been approved in the IRP process.

14 Q Has the company included any specific growth
15 projections for DER penetrations on the system to support
16 that concern that the penetration level is increasing at a
17 rate that you need to begin that lead time now?

18 A (Witness Robinson) Well, it's important to
19 consider that we do centralized dispatch here in the
20 Southeast, and it's not just Georgia Power resources, but we
21 have to consider other resources that are fed off the
22 transmission system as well as we're looking at dispatching
23 the pool.

24 So as we see distributed energy resources
25 proliferate throughout the state of Georgia, not just

1 Georgia Power Company, and demand-side resources, those
2 types of things that will be integrated by a DERMS system,
3 those are the things we're anticipating, as well as the time
4 it takes to integrate that system alongside existing
5 systems.

6 Q But you haven't included in your testimony any
7 specific projections about that penetration and the timeline
8 for what you expect those penetration levels to look like?

9 A (Witness Robinson) No, but the need is here.
10 We have the RDR program that was approved in the IRP. We
11 have other customer-owned behind-the-meter resources that
12 can run parallel with the system. We must have visibility
13 and predictability. Those are the two most important
14 things. We need to know when those systems are online, when
15 we can expect them to be online, so that we can consider
16 them in centralized dispatch. That's the problem that
17 California has is they don't know where their systems are.

18 Q Okay. I have a couple similar questions for
19 the proposed rules changes that also start on page 57 of
20 your testimony to require new customer generation facilities
21 over 250kW to include the communication equipment for
22 interoperability, if I'm using that description correctly.

23 A (Witness Robinson) That's correct.

24 Q You have a claim here that as the number of
25 customer-owned DG systems grows, that there may be a limit

1 to additional DG growth without this rules change and that
2 this rules change can avoid that scenario and make
3 additional growth possible. Am I describing that correctly?

4 A (Witness Robinson) That's correct. And I
5 believe that's what IEEE 1547 anticipates as well which is
6 industry standard that we design the systems to and that we
7 use in planning our system.

8 Q Could you describe what the obstacle is that
9 the company would face or that the grid would face in
10 customers in trying to add additional customer-owned
11 generation without this rules change?

12 A (Witness Robinson) Sure. If you do not have
13 visibility or you do not have control of inverters, so you
14 can't change either harmonic settings or the way that the
15 system interacts with faults on the system or contributes to
16 reactive supply, it will limit our ability to incorporate or
17 to have more DER systems on the distribution system.

18 Q And is there a threshold level where you think
19 those concerns actually become a problem in reality in
20 operating the grid and integrating new DER?

21 A (Witness Robinson) I think any time you have
22 multiple DERs on the system, you need the ability to see
23 them, predict them, and ultimately be able to have the
24 control that IEEE 1547 talks to, and that's what we're
25 asking for in these rules and regs. It's already in our

1 interconnection agreement. It is an industry standard, and
2 so the minute you put a DER on the system that can parallel
3 with the system, and I'm not really sure why you would not
4 want to see it or be able to interface with it. That is a
5 problem. That is why other jurisdictions have the
6 reliability issues that they have.

7 Q Okay. So you're testifying that there's not
8 some threshold level that we need to wait -- that the
9 company would --

10 A (Witness Robinson) Correct.

11 Q -- want to wait to integrate that?

12 MR. THOMASSON: Those are all the questions I
13 have. Thanks.

14 MADAM CHAIR PRIDEMORE: Interstate Gas Supply.

15 MR. WISE: No questions.

16 MADAM CHAIR PRIDEMORE: The Kroger Company.

17 MR. BOEHM: No questions. Thank you.

18 MADAM CHAIR PRIDEMORE: MARTA.

19 MS. STURM: No questions.

20 MADAM CHAIR PRIDEMORE: Resource Supply
21 Management.

22 MR. CLARKSON: No questions.

23 MADAM CHAIR PRIDEMORE: Sierra Club.

24 CROSS-EXAMINATION

25

1 BY MS. ARIZA:

2 Q Good morning, Panel.

3 THE PANEL: Good afternoon.

4 Q Right. Sorry. For the record, my name is
5 Isabella Ariza and I represent the Sierra Club in this
6 proceeding.

7 On page 20, lines 7 through 9 of your rebuttal
8 testimony, you state that all parties generally agree with
9 the current CCO-ARO cost recovery methodology except for GAM
10 witness Pollock. Do you see that?

11 A (Witness Abramovitz) Yes, that is correct.

12 Q You say that all parties agree, but the Sierra
13 Club doesn't agree; right?

14 A (Witness Abramovitz) We were just referencing
15 testimony that was filed in this case.

16 Q Okay. And in preparing your rebuttal, you
17 reviewed staff's direct testimony filed by Mr. Trokey and
18 Mr. Smith on October 20, 2022; correct?

19 A (Witness Abramovitz) We did.

20 Q In that testimony, staff conditions their
21 determination of the prudence of your CCR-ARO expenditures
22 on whether EPA finds that Georgia Power's closure plans
23 comply with federal regulations; correct?

24 A (Witness Abramovitz) That's correct.

25 Q And staff also refers to EPA's regulations that

1 prohibit leaving coal ash in groundwater. Is that your
2 understanding?

3 A (Witness Abramovitz) That's my understanding.

4 Q And EPA recently issued a final determination
5 on November 18 interpreting their own CCR rule to mean that
6 leaving coal ash in groundwater violates federal law;
7 correct?

8 A (Witness Abramovitz) I believe that was a
9 specific case in Ohio. I don't think was a specific ruling
10 for broader EPA interpretation.

11 Q But EPA doesn't limit its findings to Ohio at
12 all, does it? Instead it reaffirms that surface
13 impoundments cannot be closed with coal ash and groundwater;
14 correct?

15 A (Witness Abramovitz) I would disagree with
16 that, just on the premise that we're in compliance with all
17 federal and state regulations with these coal ash ponds
18 here, and that EPA ruling was based on a specific instance
19 in Ohio.

20 Q So now that EPA has -- you understand that the
21 EPA has stated that leaving coal ash in groundwater does not
22 comply with federal rules, so I assume Georgia Power will
23 not change its closure plans?

24 A (Witness Abramovitz) What I can say is we're
25 going to execute on the plans that were approved by this

1 Commission in the integrated resource plan proceedings that
2 are still in compliance with all federal and state
3 regulations.

4 Q So as of today, despite EPA's recent ruling,
5 ratepayers will continue paying ash pond closures that will
6 leave coal ash in groundwater?

7 MADAM CHAIR PRIDEMORE: Go ahead.

8 MR. HEWITSON: Well, I was going to object
9 because it's been asked and answered. But I was also
10 going to object that the EPA ruling, as Mr.
11 Abramovitz, just noted does not apply to Georgia
12 Power's ash pond, so the premise of the question
13 would be incorrect.

14 MADAM CHAIR PRIDEMORE: Sustained. You may
15 rephrase.

16 I would also like to state for the record that,
17 Mr. Abramovitz, you said this Commission approved the
18 treatment of coal ash. This Commission, we're not
19 environmental regulators. That would be EPD that
20 approved the company's plans for coal ash
21 remediation.

22 BY MS. ARIZA:

23 Q Okay. Then one final question. If you're
24 moving forward with plans that, while you say are in
25 compliance with EPA's rule, other parties would not agree

1 with that.

2 First, let me ask you, would you agree there's
3 disagreement on whether your plans comply with EPA's
4 regulations?

5 A (Witness Abramovitz) I think this exchange
6 right now would answer that question.

7 Q Okay. And wouldn't you agree that moving
8 forward with your plans, leaving coal ash in groundwater,
9 would be imprudent?

10 A (Witness Abramovitz) No, I would disagree,
11 because our plans, as I've said before, are in compliance
12 with all federal and state regulations, which means they're
13 not imprudent.

14 Q But Georgia Power did testify that ash ponds
15 like Hammond EP3, Yates Ash Management area, McDonough AP1
16 and Scherer AP1 will leave coal ash in groundwater after
17 closure?

18 A (Witness Abramovitz) We have testified to that
19 and that's still in compliance with Georgia EPD and federal
20 EPA rules and regulations.

21 MS. ARIZA: Okay. No further questions.

22 Thank you.

23 MADAM CHAIR PRIDEMORE: SACE and Southface.

24 MR. DOWDY: No questions.

25 MADAM CHAIR PRIDEMORE: USDOE.

1 MS. MEDLYN: No questions.

2 MADAM CHAIR PRIDEMORE: Georgia Watch.

3 MS. COYLE: No questions.

4 MADAM CHAIR PRIDEMORE: Rebuttal.

5 MR. HEWITSON: Thank you, Madam Chair.

6 MADAM CHAIR PRIDEMORE: Redirect.

7 REDIRECT EXAMINATION

8 BY MR. HEWITSON:

9 Q Panel, just a few questions for you. Early --
10 earlier this morning Mr. Walsh asked you some questions. He
11 took you through some math regarding the earnings band and
12 the width of the earnings band and the valuation of basis
13 points. The question I want to ask you, though, is, is the
14 company guaranteed any specific return?

15 A (Witness Abramovitz) No, we're not. It's
16 based on our performance, factors like weather, customer
17 growth, customer -- declines in customer growth. The way
18 rates are set is on an ROE set point, but that's just the
19 set on rates, it does not guarantee a return.

20 Q And what does the company need to do in order
21 to earn a return as allowed by this Commission?

22 A (Witness Abramovitz) We have to manage our
23 business effectively and manage our cost effectively and
24 spend dollars prudently.

25 Q And once rates are set the company takes on the

1 risk that it can operate efficiently so as to be able to
2 earn that return; is that correct?

3 A (Witness Abramovitz) That is correct.

4 Q Mr. Walsh also asked you -- asked if your
5 reference on page 2, line 27, that staff's proposal is
6 radical is because it's radically different from Mr. Coyne's
7 exert opinion. Do you remember that question?

8 A (Witness Abramovitz) I do.

9 Q Is staff's proposal also radical because it
10 would be a significant departure from what this Commission
11 has previously awarded to the company?

12 A (Witness Abramovitz) Yes.

13 Q Mr. Walsh asked you several questions about
14 various O&M expenses like service awards and things of that
15 nature; right?

16 A Yes.

17 Q Have these expenses been routinely included in
18 the cost of service for the company?

19 A (Witness Abramovitz) Yes, they have.

20 Q Have they been treated in prior cases that are
21 recoverable costs because they're used to serve customers?

22 A (Witness Abramovitz) Yes.

23 MR. HEWITSON: Thank you, Panel. That's all
24 the questions I have for you.

25 Madam Chair, I ask that the panel -- that

1 Georgia Power's exhibits -- we didn't have any
2 exhibits -- that the panel be excused.

3 MADAM CHAIR PRIDEMORE: I believe the
4 Commissioner has a question first.

5 COMMISSIONER MCDONALD: You stated that the ROE
6 doesn't guarantee a profit for the company; right?

7 MR. ABRAMOVITZ: That's correct.

8 COMMISSIONER MCDONALD: What happens when the
9 bottom of the band is not achieved?

10 MR. ABRAMOVITZ: So in the instance that the
11 bottom of the ROE band wouldn't be achieved, the
12 company would have the ability to come and ask for
13 rate relief. That's a request. The Commission
14 doesn't have to grant it.

15 COMMISSIONER MCDONALD: Thank you.

16 MADAM CHAIR PRIDEMORE: Any other questions
17 from Commissioners? Hearing none, we're going to
18 break for lunch. We will be back at 1:30.

19 (Whereupon a break was taken.)

20 MADAM CHAIR PRIDEMORE: Very good. We are back
21 on the record.

22 Mr. Marzo, you have a new panel.

23 MR. MARZO: Thank you, Madam Chair. At this
24 time I would like to call Mr. James Coyne and
25 Mr. Steven Fetter to the stand. They are seated.

1 With your permission, Madam Chair, I would swear them
2 in.

3 MADAM CHAIR PRIDEMORE: Please go ahead.

4 MR. MARZO: Gentlemen, would you please raise
5 your right hand.

6 Thereupon,

7 JAMES COYNE,
8 STEVEN FETTER,
9 having been duly sworn, testified as follows:

10 DIRECT EXAMINATION

11 BY MR. MARZO:

12 Q All right. Thank you. You may lower your
13 hands.

14 Mr. Coyne, would you please state your full
15 name and your business address again for the record?

16 A (Witness Coyne) James M. Coyne. And my
17 business address is 293 Boston Post Road, Marlborough,
18 Massachusetts, 01752.

19 Q Thank you, Mr. Coyne.

20 And, Mr. Fetter, would you please do the same.

21 A (Witness Fetter) My name is Steven M. Fetter.
22 I am president of Regulation UnFettered, my own advisory
23 firm, and my address is 1240 West Sims Way, Port Townsend,
24 Washington, 98368.

25 Q Thank you, Mr. Fetter.

 Did you both previously file testimony in this

1 case?

2 A (Witness Coyne) I did.

3 A (Witness Fetter) Yes, I did.

4 Q Okay. Thank you.

5 Mr. Coyne, on November 18th of this year, did
6 you prefile or cause to be prefiled 52 pages of rebuttal
7 testimony in question-and-answer format in this docket?

8 A (Witness Coyne) I did.

9 Q And, Mr. Coyne, are there any corrections which
10 you need to make to your prefiled rebuttal testimony?

11 A (Witness Coyne) No.

12 Q If I were to ask you the same questions today
13 under oath, would your answers be the same as set forth in
14 your prefiled rebuttal testimony?

15 A (Witness Coyne) Yes.

16 Q And, Mr. Fetter, on November 18 did you prefile
17 or cause to be prefiled 11 pages of rebuttal testimony in
18 question-and-answer format in this docket?

19 A (Witness Fetter) Yes, I did.

20 Q And, Mr. Fetter, are there any corrections
21 which you need to make to your prefiled rebuttal testimony?

22 A (Witness Fetter) Not at this time.

23 Q Okay. If I were to ask you the same questions
24 today under oath, would your answer be the same as set forth
25 in your prefiled rebuttal testimony?

1 A (Witness Fetter) Yes, they would.

2 MR. MARZO: Madam Chair, just for the record,

3 the court reporter has previously been provided a

4 copy of the prefiled rebuttal testimony. I'm going

5 to now ask that the testimony of Mr. Coyne and the

6 testimony of Mr. Fetter be copied into the record as

7 if given orally here today.

8 MADAM CHAIR PRIDEMORE: So moved.

9 MR. MARZO: Thank you.

10 (Whereupon, the prefiled rebuttal testimony

11 of James M. Coyne and Steven M. Fetter follows:)

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**REBUTTAL TESTIMONY OF
JAMES M. COYNE
ON BEHALF OF
GEORGIA POWER COMPANY
DOCKET NO. 44280**

I. INTRODUCTION

1 **Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.**

2 A. My name is James M. Coyne, and I am employed by Concentric Energy Advisors, Inc.
3 ("Concentric") as a Senior Vice President. My business address is 293 Boston Post Road
4 West, Suite 500, Marlborough, Massachusetts 01752.

5 **Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS PROCEEDING?**

6 A. Yes. I submitted direct testimony to the Georgia Public Service Commission (the
7 "Commission") on behalf of Georgia Power Company ("Georgia Power" or the
8 "Company") on June 24, 2022.

9 **Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

10 A. The purpose of my rebuttal testimony is to respond to the direct testimonies of the
11 following witnesses as they relate to the appropriate return on equity ("ROE") and capital
12 structure for Georgia Power: Mr. Michael P. Gorman on behalf of the Commission's Public
13 Interest Advocacy Staff ("Staff"), Ms. Billie S. LaConte on behalf of Georgia Association
14 of Manufacturers ("GAM"), Mr. Mark E. Ellis on behalf of Georgia Interfaith Power &
15 Light ("GIPL"), Ms. Maureen L. Reno on behalf of the U.S. Department of Defense and
16 Federal Executive Agencies ("DOD"), and Mr. Steve W. Chriss on behalf of the
17 Commercial Group. I collectively refer to these individual witnesses as "Intervenor
18 Witnesses."

1 **Q. ARE YOU SPONSORING ANY EXHIBITS AS PART OF YOUR REBUTTAL**
2 **TESTIMONY?**

3 A. No.

4 **Q. HOW IS THE REMAINDER OF YOUR REBUTTAL TESTIMONY**
5 **ORGANIZED?**

6 A. My rebuttal testimony is organized to respond to the Intervenor Witnesses by issue, starting
7 in Section II with an overview and summary of the results and recommendations presented
8 by the various ROE witnesses in this proceeding. Section III discusses economic and
9 capital market conditions and how those conditions are affecting the various models used
10 to estimate the cost of equity for Georgia Power. In Section IV, I address the proper
11 application of the cost of equity analytical models employed by me and the Intervenor
12 Witnesses, including the Discounted Cash Flow (“DCF”) model, the Capital Asset Pricing
13 Model (“CAPM”), the Bond Yield Plus Risk Premium (“Risk Premium”) model and the
14 Expected Earnings model. In Section V, I respond to comments raised by certain witnesses
15 with respect to Georgia Power’s proposed capital structure and cost of debt, and I explain
16 why that capital structure is reasonable by comparison to the proxy group. In Section VI, I
17 respond to comments regarding Georgia Power’s company-specific risk factors raised by
18 the Intervenor Witnesses. Lastly, in Section VII, I summarize my key conclusions and
19 continue to recommend an 11.00 percent ROE (including flotation costs) and Georgia
20 Power’s actual capital structure of 56.0 percent common equity and 44.0 percent long-term
21 debt.

22 **II. SUMMARY OF TESTIMONY**

23 **Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE ANALYSIS AND**
24 **RECOMMENDATIONS PROVIDED BY THE INTERVENOR WITNESSES**
25 **REGARDING THE APPROPRIATE ROE AND CAPITAL STRUCTURE FOR**
26 **GEORGIA POWER?**

27 A. My key conclusions are as follows:

- 1 (1) The Intervenor Witnesses' analyses contain flaws and inconsistencies that produce
2 some results well below recent authorized returns for electric utilities, particularly
3 those comparable to Georgia Power. Some recommendations are even 50 to 100
4 basis points below prevailing costs of debt for utilities. Such recommendations
5 should be given no weight as no investor would take on the perpetual risks of equity
6 ownership when they could earn a higher return for safer debt investments that have
7 a senior claim on cash flows.
- 8 (2) The cost of equity for regulated utility companies is being affected by several key
9 factors in the current and prospective capital markets, including the interest rate
10 environment and central bank monetary policy, as well as current inflationary
11 pressure. Inflation has escalated to levels not seen since the early 1980s; interest
12 rates across the yield spectrum have increased; and capital market volatility remains
13 elevated. These circumstances reinforce the importance of considering the results
14 of multiple models, as I have with the DCF, CAPM, Risk Premium, and Expected
15 Earnings approaches.
- 16 (3) All models are subject to certain limiting assumptions. However, in market
17 conditions where ROE estimation models are producing return estimates below the
18 current cost of debt for utilities (e.g., Mr. Ellis' DCF and CAPM estimates), utility
19 regulators recognize that such low returns are not compensatory for investors.
20 Rather than endorsing the results of a specific methodology, the Commission
21 should consider how current market conditions affect the risks for equity investors
22 as well as take into account the results of a broader range of ROE estimation
23 methodologies.

24 **Q. PLEASE SUMMARIZE THE COST OF CAPITAL RECOMMENDATIONS**
25 **PRESENTED BY THE INTERVENOR WITNESSES IN THIS PROCEEDING?**

26 A. The Intervenor Witnesses who performed an independent ROE analysis (Mr. Gorman, Ms.
27 Reno, and Mr. Ellis) recommend an authorized ROE for Georgia Power between 5.54
28 percent and 9.47 percent. Other Witnesses did not perform their own ROE analysis, and
29 instead adjusted certain inputs in my analyses (Ms. LaConte) or referenced authorized

1 returns for electric utilities in other jurisdictions (Mr. Chriss). Based on adjustments to my
2 analyses using her preferred inputs, Ms. LaConte asserts that Georgia Power's cost of
3 equity does not exceed 9.83 percent.¹

4 As it relates to capital structure, Ms. Reno accepts the Company's capital structure
5 recommendation.² Mr. Gorman accepts the Company's proposed 56 percent equity ratio
6 for 2023, but recommends the Commission impute a hypothetical capital structure of 51
7 percent equity for 2024 and 2025.³ Ms. LaConte recommends a capital structure that
8 contains no more than 53 percent common equity.⁴ Lastly Mr. Ellis recommends a capital
9 structure that contains 61.70 percent equity to offset his 5.54 percent ROE
10 recommendation.

11 As is evident, there is a broad array of recommendations from multiple witnesses. Notably,
12 recommendations as low as 5.54 percent are below any authorized return for any electric
13 utility in the last 40 years⁵ and are lower than current market indicators of utility and
14 corporate debt costs. Some of the recommendations are supported by analytical approaches
15 while others are more judgmental or based on decisions from other jurisdictions. I submit
16 that the appropriate method for determining the cost of capital is through the application of
17 rigorous analysis using financial models and current market data from reliable sources.

18 **Q. PLEASE PROVIDE AN OVERVIEW OF THE INTERVENOR WITNESSES'**
19 **ANALYTICAL RESULTS IN THIS PROCEEDING?**

20 A. Figure 1 summarizes the results from the Intervenor Witnesses which form the basis of
21 their recommendations.

1 Direct Testimony of Billie S. LaConte, at 9.

2 Direct Testimony of Maureen S. Reno, at 6.

3 Direct Testimony of Michael P. Gorman, at 3.

4 Direct Testimony of Billie S. LaConte, at 3.

5 Source: S&P Capital IQ Pro, Regulatory Research Associates. 8.70 percent is the lowest authorized ROE for an electric utility since 1980, excluding cases for limited-issue riders, formula-based rate plans, and ROEs that include penalties.

Figure 1: ROE Ranges and Recommendations of the Intervenor Witnesses

	Staff Mr. Gorman⁶	GAM Ms. LaConte⁷	GIPL Mr. Ellis⁸	DOD Ms. Reno⁹
DCF Results	8.07% - 9.20%	9.09%	5.97%	8.15% - 9.47%
CAPM/ECAPM Results	9.88% - 10.93%	9.84% - 10.57%	5.41%	8.23% - 9.84%
Risk Premium Results	9.21% - 9.28%	9.46%	NA	NA
Expected / Comparable Earnings Results	NA	NA	NA	9.85% - 10.76%
Equity Ratio Recommendation	56% (2023); 51% (2024 - 2025)	≤ 53%	61.70%	56%
ROE Recommendation (Range)	9.45% (9.00%- 9.90%)	≤ 9.83%	5.54%	9.47% (8.81% - 9.47%)

There are a number of flaws and inconsistencies with the analyses conducted by the Intervenor Witnesses. I address each analytical approach and explain why their assumptions are unreasonable. At the outset, one must question analyses producing results that are more than 300 basis points below any return authorized for any electric utility in at least 40 years.

⁶ Direct Testimony of Michael P. Gorman, at 32-33, 47, 52 59, 60.

⁷ Direct Testimony of Billie S. LaConte, at 9.

⁸ Direct Testimony of Mark E. Ellis, at 6.

⁹ Direct Testimony of Maureen L. Reno, at 7, 49.

1 **Q. PLEASE DESCRIBE THE LEGAL STANDARDS THAT MUST BE MET TO**
2 **ESTABLISH THE AUTHORIZED ROE FOR A REGULATED PUBLIC UTILITY**
3 **SUCH AS GEORGIA POWER.**

4 A. As discussed in my direct testimony, the standards for a just and reasonable return
5 established by the United States Supreme Court in the *Hope* and *Bluefield* cases are:

6 (1) Financial integrity: the return must be adequate to ensure the company's
7 financial soundness and support credit quality;

8 (2) Capital attraction: the return must be sufficient to enable the company to attract
9 capital on reasonable terms and conditions; and

10 (3) Comparable return: the return must be comparable to those available to
11 investors in firms with commensurate risk.

12 Importantly, in *Bluefield*, the U.S. Supreme Court recognized that a return may be
13 reasonable at one time, but may become too high or too low at another time due to changes
14 affecting investment opportunities, and market or business conditions.¹⁰ This principle is
15 relevant because, as discussed below, certain of the Intervenor Witnesses refer to recent
16 authorized ROEs to support their recommendations, but do not fully consider the
17 magnitude of the change in market conditions since those ROEs were determined.

18 **Q. SEVERAL OF THE INTERVENOR WITNESSES (GORMAN, LACONTE, RENO,**
19 **CHRISS) REFERENCE AUTHORIZED ROES FOR ELECTRIC UTILITIES IN**
20 **OTHER JURISDICTIONS. DO YOU AGREE THAT THESE RETURNS ARE**
21 **RELEVANT IN ESTABLISHING THE ROE FOR GEORGIA POWER IN THIS**
22 **PROCEEDING?**

23 A. National average returns must be placed in the proper context in order to be useful. While
24 I agree that investors consider authorized returns in other states in assessing the

10 *Bluefield Water Works v. Public Service Commission*, 262 U.S. 679, 692 (1923).

1 reasonableness of the authorized ROE for Georgia Power, I have several concerns with the
2 nationwide average ROE information presented by the Intervenor Witnesses. First, the
3 averages referenced by Mr. Gorman and Mr. Chriss include ROE determinations for
4 transmission and distribution-only (“T&D”) electric utilities, as well as determinations in
5 formula rate proceedings in which the ROE is determined by a formula solely tied to
6 changes in Treasury bond yields. These ROE determinations are not comparable to
7 authorized ROEs for vertically integrated electric utilities, nor are they comparable to
8 determinations that are based on the use of various financial models as is the process used
9 by the Commission. Vertically integrated electric utilities have a higher level of business
10 risk than T&D utility companies that do not own regulated generation.¹¹ This higher risk
11 profile differentiates integrated electric utilities from T&D utilities and supports a higher
12 authorized ROE and equity ratio in the capital structure. Lastly, their references to average
13 authorized ROEs do not include approvals earlier this year by the Florida Public Service
14 Commission to increase the authorized ROEs of Florida Power & Light, Tampa Electric
15 Company, and Duke Energy Florida due to increases in the 30-year Treasury yield outlined
16 as part of those utilities’ most recent rate case settlements.

17 Second, market conditions at the time the authorized returns were established are very
18 different than conditions today and going forward. For example, equity returns set when
19 interest rates were very low in 2020 are not a reasonable basis of comparison for an
20 appropriate ROE in 2023 when bond yields have increased and are projected to continue
21 increasing as the economy recovers and the Federal Reserve moves to a more neutral
22 monetary policy. After the decline in interest rates in 2020-2021 driven by the Federal
23 Reserve’s unprecedented actions to respond to the COVID-19 pandemic, interest rates have
24 increased by approximately 160 to 230 basis points since the settlement adopting an ROE
25 of 10.50 percent for Georgia Power was authorized in December 2019.¹² Since my direct

11 Moody’s Investors Service, Rating Methodology for Electric and Gas Utilities, June 23, 2017, at 21.

12 The 30-day average 30-year Treasury bond yield was 2.28 percent as of December 17, 2019. The current 30-day average on the 30-year Treasury bond yield is 3.92 percent as of October 31, 2022. The 30-day average A-rated Utility bond yield was 3.41 percent as of December 17, 2019, compared to 5.75 percent for the 30-day average as of October 31, 2022. The 30-day average Baa-rated Utility bond yield was 3.74 percent as of December 17, 2019, compared to 6.06 percent for the 30-day average as of October 31, 2022.

1 testimony was prepared in April 2022, the 30-day average 30-year Treasury yield has
2 increased by more than 100 basis points and currently exceeds even the projections of the
3 30-year Treasury yield at the time I prepared my direct testimony. Although state utility
4 commissions mitigated ROE reductions in 2020-2021 due to the knowledge that interest
5 rates were being artificially suppressed due to the Federal Reserve's actions,¹³ the use of
6 prior decisions during that time period which set ROEs under previously lower interest
7 rates understates the forward-looking cost of equity and the very different rising interest
8 rate environment that we are now experiencing.¹⁴ In other words, authorized ROEs that
9 may have been considered reasonable and appropriate in 2020 and 2021, and even into the
10 first half of 2022, are not reasonable in the current market environment, consistent with
11 *Bluefield*.

12 **Q. DOES THE ANNUAL AVERAGE AUTHORIZED ROE APPROPRIATELY**
13 **REFLECT GEORGIA'S MORE CONSTRUCTIVE REGULATORY**
14 **ENVIRONMENT?**

15 A. No. Figure 2 below presents the annual average authorized ROEs for vertically integrated
16 electric utilities by Regulatory Research Associates' ("RRA") ranking of the regulatory
17 environment (Above Average, Average, and Below Average). As Figure 2 demonstrates,
18 authorized ROEs by regulatory commissions ranked as "Above Average" are
19 approximately 40 to 60 basis points above the average authorized ROE in "Average"
20 jurisdictions.

13 S&P, The Big Picture: 2022 Electric, Natural Gas and Water Utilities Outlook (Oct 2021) ("S&P Oct. 2021") at 5 (finding that the spread between authorized ROE and interest rates increased because state utility commissions "recognized that long-term bond yields have been artificially suppressed due to the Fed[eral] Reserve's unprecedented intervention in the capital markets."; *see also* RRA, Major Energy Rate Case Decisions in the US—January-June 2022 (July 27, 2022) ("RRA July 22, 2022"). at 6 ("the gap between authorized ROEs and interest rates widened somewhat over this period, largely as a result of regulators' often-unstated understanding that the decline in interest rates caused by Federal Reserve intervention was unusual.")).

14 RRA July 29, 2022, at 7 (with interest rates on the rise "the average authorized returns for full year 2022 and 2023 may edge higher"); *accord id.* at 4 ("Authorized returns may edge slightly higher going forward as the U.S. Federal Reserve continues efforts to tamp down soaring inflation via a series of interest rate hikes, the first of which was announced in March").

**Figure 2: Annual Average Authorized ROE by Commission Ranking
for Vertically Integrated Electric Utilities¹⁵**

	Above Average	Average	Below Average
2019	10.06%	9.60%	9.70%
2020	9.89%	9.47%	9.45%
2021	10.01%	9.40%	8.85%
2022	10.15%	9.62%	9.35%

ROE recommendations that are more consistent with those authorized by “Below Average” or “Average” jurisdictions would undermine investors’ perceptions of Georgia’s supportive and constructive regulatory climate, ultimately increasing the Company’s regulatory risk.

Q. DOES CURRENT MARKET DATA ILLUSTRATE THE UNREASONABLENESS OF MR. ELLIS’S ROE RECOMMENDATION?

A. Yes. Current utility bond yields measured by Moody’s utility bond indices are approximately 50 to 80 basis points *above* Mr. Ellis’s ROE recommendation.¹⁶ It is simply illogical to expect that a rational investor would take on the risk of a utility equity investment when they could earn a higher return from a safer bond that has a senior claim on cash flow. Mr. Ellis attempts to adjust current utility bond yields below his cost of equity estimates to account for certain risk premia (e.g., liquidity risk) and concludes without any evidence that an equity premium between 67 and 124 basis points would be a sufficient premium for equity investors.¹⁷ There is no evidence to demonstrate that equity investors would be willing to accept such a small premium for taking on the risk of utility equity investment.

¹⁵ Source: Regulatory Research Associates. Vertically integrated electric rate cases completed through November 3, 2022. Includes the ROE “trigger” settlement provisions approved by the Florida Public Service Commission in 2022 for Florida Power & Light (10.80% ROE), Duke Energy Florida (10.10% ROE), and Tampa Electric Company (10.20% ROE).

¹⁶ Source: Federal Reserve Bank of St. Louis FRED Economic Database, as of October 31, 2022.

¹⁷ Direct Testimony of Mark E. Ellis, at 74.

1 Mr. Ellis's 5.54 percent ROE recommendation is substantially below national average
2 authorized ROEs for vertically integrated electric utilities. In fact, it is nearly 400 basis
3 points below the 9.53 percent average authorized ROE for vertically integrated electric
4 utilities in 2021 cited by Ms. LaConte and Ms. Reno. Mr. Ellis' higher equity ratio
5 recommendation of 61.70 percent does not offset the unreasonableness of his ROE
6 recommendation. The weighted cost of equity produced by Mr. Ellis's ROE and capital
7 structure recommendation is 3.42 percent (i.e., 5.54 percent multiplied by 61.70 percent).
8 If adopted, Mr. Ellis's weighted cost of equity would be well below that recently authorized
9 for vertically integrated electric utilities. The average weighted cost of equity for vertically
10 integrated electric utilities in 2022 is 5.06 percent,¹⁸ 163 basis points above Mr. Ellis's
11 recommended weighted cost of equity. In fact, the 2022 average authorized weighted cost
12 of equity is only 39 basis points below his ROE recommendation, further demonstrating
13 the unreasonableness of his recommendation. Mr. Ellis's recommendation is far too low to
14 be reasonable and would not satisfy the *Hope* and *Bluefield* standards for a risk comparable
15 return that would allow the Company to attract capital and maintain its financial integrity.
16 Moreover, it would represent a substantial departure from Georgia's supportive regulatory
17 environment, introducing significant regulatory risk and higher costs of both debt and
18 equity to the detriment of customers.

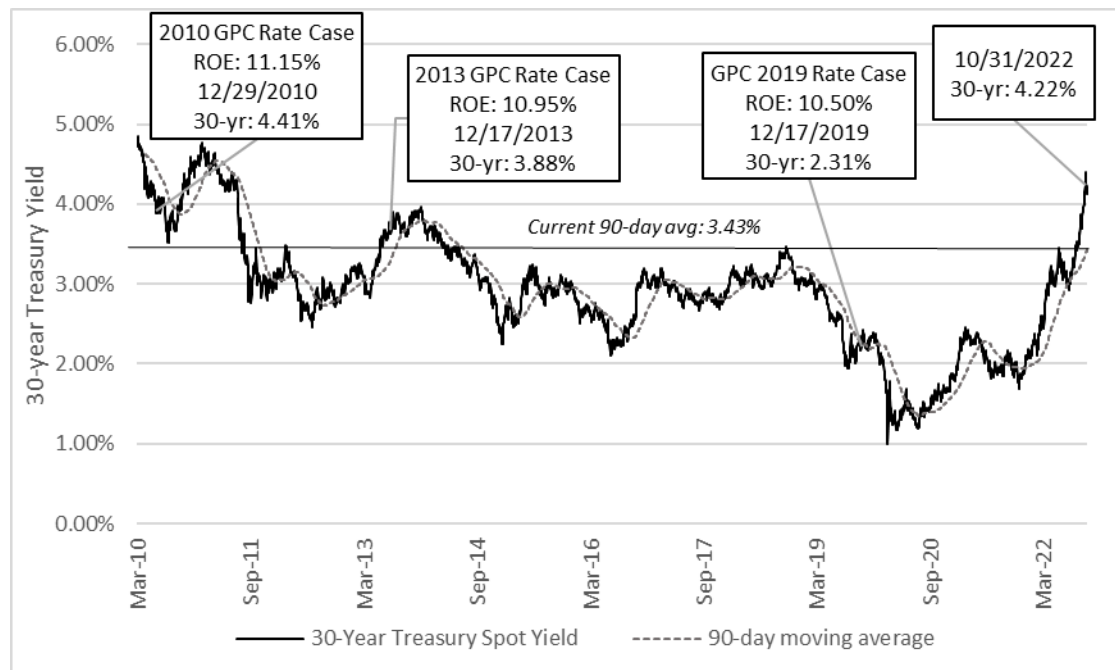
19 **Q. HOW DOES THE CURRENT INTEREST RATE ENVIRONMENT COMPARE**
20 **TO THE ENVIRONMENT DURING THE COMPANY'S PRIOR RATE CASES?**

21 A. As shown in Figure 3 below, the interest rate environment is currently above the levels
22 experienced during the Company's 2019 rate case and 2013 rate case. Specifically, the spot
23 yield on the 30-year Treasury bond as of October 31, 2022 was 4.22 percent, 191 basis
24 points above the spot yield at the time of the Commission's decision in the Company's
25 2019 rate case and 34 basis points above the yield at the time of the Commission's decision

18 Source: Regulatory Research Associations. Authorized ROE and equity ratios for vertically integrated electric utilities through November 3, 2022. Excludes limited rider rate proceedings and ROEs authorized in formula rate proceedings in which the ROE is adjusted based on changes in Treasury bond yields. Excludes decisions from jurisdictions that include non-investor supplied capital in the ratemaking capital structure.

in the 2013 rate case when the Commission approved a 10.95 percent ROE. The last time the 30-year Treasury yield was 4.22 percent was in July 2011. Even if we looked to the 90-day moving average, the current 90-day average 30-year Treasury yield of 3.43 percent is at its highest level since August 2014.

Figure 3: 30-Year Treasury Yield (2010-2022)¹⁹



The Intervenor Witnesses' recommendations to *reduce* the Company's authorized ROE runs counter to the current capital market environment of *increasing* capital costs that are at their highest levels in at least seven years. My 11.00 percent ROE recommendation, on the other hand, reflects less than 30 percent of the 191-basis point increase in the 30-year Treasury bond yield since December 2019 when the Commission authorized the Company's current 10.50 percent ROE.²⁰

¹⁹ Source: Bloomberg Professional.

²⁰ The difference between 10.50% and 11.00% is 0.50%. $0.50\% / 1.91\% = 26\%$.

III. CAPITAL MARKET CONDITIONS

Q. PLEASE SUMMARIZE THE ECONOMIC AND FINANCIAL MARKET CONDITIONS OVER THE PAST SEVERAL MONTHS SINCE YOU SUBMITTED YOUR DIRECT TESTIMONY?

A. The conditions described in my direct testimony have continued since April 2022 and the primary capital market indicators continue to support higher return requirements by utility equity investors. Specifically, (1) inflation remains at levels not seen since the early 1980s, (2) interest rates across the yield spectrum have continued to increase, and (3) the elevated capital market volatility has sustained longer than anticipated.

It is important to consider current and expected conditions in the general economy and financial markets because the authorized ROE for a public utility should allow the utility to attract investor capital at a reasonable cost under a variety of economic and financial market conditions.

Q. PLEASE DISCUSS THESE CHANGES AND ROOT CAUSES OF THESE SHIFTS IN CAPITAL MARKET CONDITIONS.

A. Inflation has been both the greatest surprise and cause for concern among both policymakers and investors. As illustrated below, inflation levels have moved within a relatively narrow band over the past twenty years (other than during the Great Recession of 2007/2008). Starting with the initial stages of the COVID-19 pandemic in 2020, inflation levels have been driven higher, reaching a peak of 9.0 percent in June of 2022 and leveling off at 7.7 percent in October 2022. Inflation is being driven by strong consumer demand and supply constraints, some of which have been exacerbated by COVID-19 related government stimulus programs in the U.S. and international lockdowns. More recently, the war in Ukraine, which began in February, is constraining the world's supply of food and fuel, pushing overall inflation higher and feeding into the cost of other products and services.

Figure 4: Consumer Price Index – All Urban, Not Seasonally Adjusted²¹



As a result of these substantially higher inflation rates, the Federal Reserve has been left little choice but to pull back on its COVID-related monetary policies and battle inflation with its only effective tool: higher interest rates. In response to the economic effects of COVID-19, the Federal Reserve had decreased the federal funds rate in March 2020 to a target range of 0.00 percent to 0.25 percent (which remained in effect until March 2022) in addition to other stimulus measures which increased the supply of money in the economy. Since I prepared my ROE analysis provided in direct testimony (with market data through April 29, 2022), the Federal Reserve has continued unwinding its quantitative easing policy and increased the target rate six times, beginning with 25 basis points on March 17, 50 basis points on May 5, 75 basis points on June 16, another 75 basis points on July 27, another 75 basis points on September 21, and another 75 basis points on November 3 to a target range of 3.75 – 4.00 percent. Expectations are for further increases this year, with FOMC participants' median projection of 4.375 percent by the end of 2022, increasing to 4.60 percent by the end of 2023.²² This demonstrates the level of Federal Reserve action necessary to reel in inflation. The Fed is willing to risk a slowdown in the economy, and it is clear that the era of record low interest rates and moderate inflation has closed. The 10-

²¹ Source: <https://tradingeconomics.com/united-states/inflation-cpi> (accessed November 11, 2022).
²² Federal Reserve Board of Governors Summary of Economic Projections, at 4 (September 21, 2022).

1 year bond, which closed out April 2022 at 2.89 percent, closed out October at 4.10 percent,
2 and the 30-year yield, which closed out April at 2.96 percent, closed out October at 4.22
3 percent, both up substantially since I developed my direct testimony. Notably, the pace of
4 the increase in Treasury bond yields escalated in September and October. For example,
5 over the four months between the end of April and the end of August, the 10-year Treasury
6 bond yield and 30-year Treasury bond yield increased by 26 and 31 basis points,
7 respectively; however, over the most recent two months (end of August to end of October),
8 the 10-year Treasury bond yield and 30-year Treasury bond yield both increased by 95
9 basis points, respectively.

10 Equity markets have also been affected. The Chicago Board Options Exchange (“CBOE”) Volatility Index (“VIX”) climbed higher, from an average of 24.3 in April to 30.0 in
11 October.²³ For context, the VIX averaged 16.9 percent from 2010-2019, indicating
12 increased levels of market volatility (and risk) for equity investors today. Because investors
13 require higher returns to compensate them for greater risk, increased equity market
14 volatility is indicative of higher return requirements for equities, including utilities.
15

16 **Q. HAVE UTILITY STOCK PRICES ALSO BEEN MORE VOLATILE IN RECENT**
17 **MONTHS?**

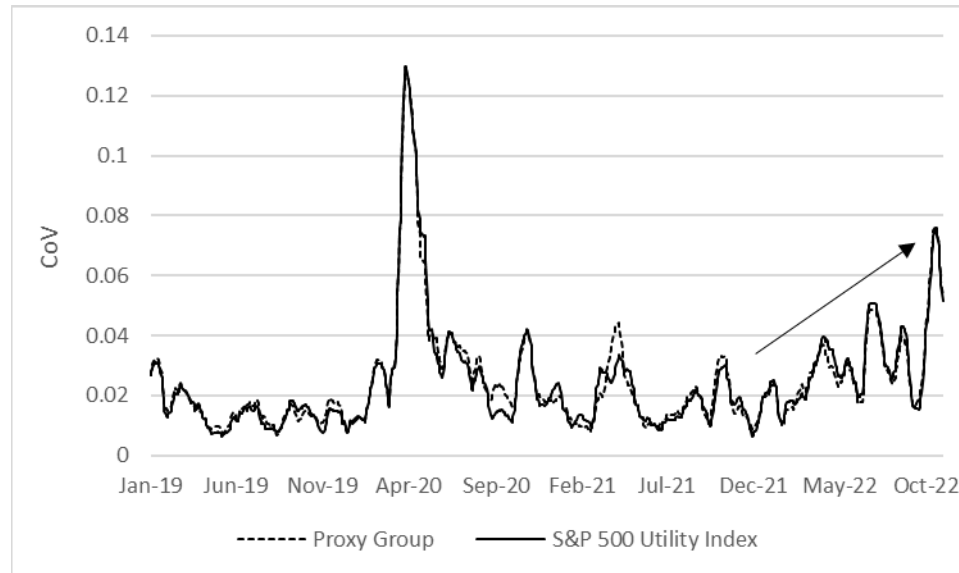
18 A. Yes, they have. The Coefficient of Variation is a measure of volatility defined as the ratio
19 of the standard deviation to the mean over a given period. I calculated the Coefficient of
20 Variation in the market price for the proxy group and the S&P 500 Utilities Index over a
21 rolling 30-day period²⁴ to assess the trend in utilities’ stock price volatility. As Figure 5
22 below shows, the Coefficient of Variation has been on an upward trend since the end of

²³ Source: Federal Reserve Bank of St. Louis FRED Economic Database. The VIX Index is a calculation designed to produce a measure of constant, 30-day expected volatility of the U.S. stock market, derived from real-time, mid-quote prices of S&P 500® Index (SPXSM) call and put options. On a global basis, it is one of the most recognized measures of volatility -- widely reported by financial media and closely followed by a variety of market participants as a daily market indicator. Source: CBOE.com

²⁴ A 30-day period is consistent with the VIX’s measurement of expected volatility over the coming 30 days.

2021 and has reached the highest point level since the onset of the COVID-19 pandemic in March 2020.

Figure 5: Utility Stock Price Volatility (2019-2022)²⁵



Q. MR. GORMAN ASSERTS THAT RISK PREMIUMS AS MEASURED BY CREDIT SPREADS ARE “REASONABLY ALIGNED WITH LONG-TERM HISTORICAL AVERAGES.”²⁶ DO YOU AGREE WITH HIS INTERPRETATION?

A. No, I do not. In his Table 12 on page 51, Mr. Gorman reviews annual average spreads between utility and corporate A-rated and Baa-rated bond yields and the 30-year Treasury yield from 2019 to 2022 and compares those to the average historical spread. However, his annual averages obscure variation over each year. Notably, his 2022 average masks the widening in credit spreads that have occurred over the course of 2022, resulting in his misleading conclusion that current credit spreads are “reasonably aligned with long-term historical averages.” As Figures 6 and 7 below show, utility credit spreads have widened considerably since January 2022 and are currently above both their 2022 annual average

²⁵ Source: Bloomberg Professional.

²⁶ Direct Testimony of Michael P. Gorman, at 51.

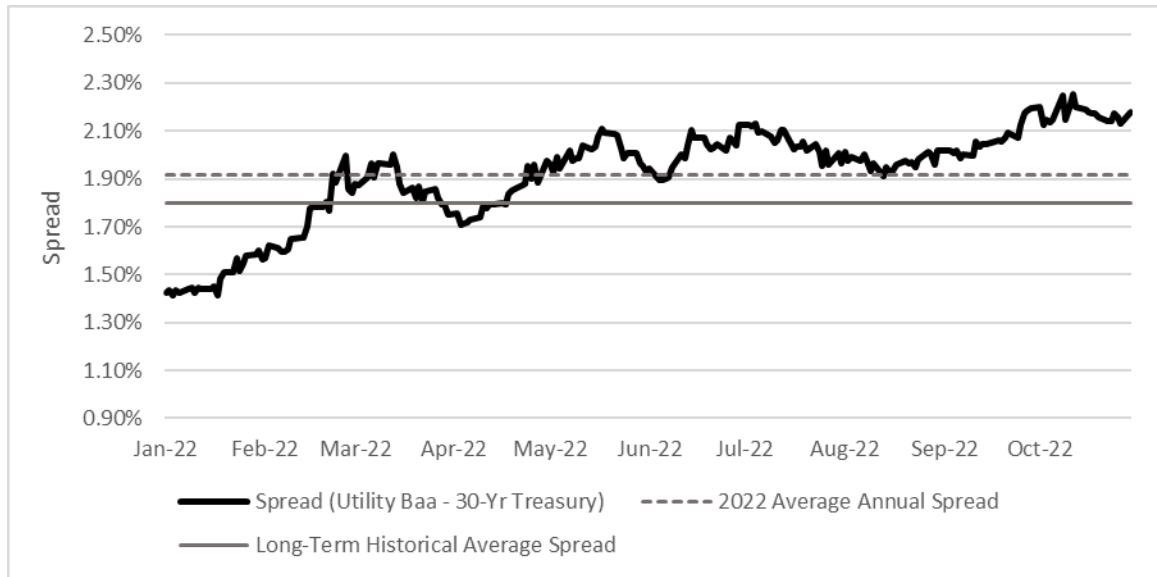
1 and long-term average. Widening credit spreads are an indication that investors are
2 requiring higher premiums to invest in utility bonds over safer government bonds.

3 **Figure 6: Credit Spread A-rated Utility – 30-Year Treasury Yield (Jan – Oct 2022)²⁷**



4
²⁷ Source: Bloomberg Professional. Long-term historical average spread reflects 1993-2022; 2022 annual average updated through October 31, 2022.

Figure 7: Credit Spread Baa-rated Utility – 30-Year Treasury Yield (Jan – Oct 2022)²⁸



Q. ARE CONDITIONS EXPECTED TO STABILIZE IN THE NEAR-TERM?

A. It does not appear so. While difficult to predict in the long-term, capital market conditions remain unsettled. The economy and capital markets remain in a tenuous state with ongoing global supply constraints and expectations of weaker consumer demand in the face of persistent inflation and higher interest rates. Interest rates may not fully reflect the effects of inflation because no one knows exactly how high interest rates must go before inflation returns to more acceptable levels. The Federal Reserve has been targeting inflation of around 2.0 percent for many years, as compared with current annualized inflation of 7.7 percent at the consumer level for the 12-month period ending in October 2022.

Looking forward, the inflation risks in the market are twofold: (1) either inflation becomes embedded in the economy if the Federal Reserve does not move aggressively enough in tightening monetary policy, or (2) the Federal Reserve responds to inflationary pressure by raising short-term interest rates to a level that causes a slowdown in economic growth or a

²⁸ Source: Bloomberg Professional. Long-term historical average spread reflects 1993-2022; 2022 annual average updated through October 31, 2022.

1 recession. The November 2022 issue of Blue Chip Financial Forecasts (“Blue Chip”)
2 reports the results of a survey of leading economists and market analysts taken in October
3 2022. Blue Chip reports that 19 percent think that by removing monetary accommodation,
4 the Federal Reserve will be successful in slowing inflation in the U.S. without causing a
5 recession, while 81 percent believe that monetary tightening will precipitate a U.S.
6 recession.²⁹

7 **Q. MR. GORMAN AND MS. RENO REFER TO RECENT UTILITY STOCK**
8 **PERFORMANCE TO SUPPORT THEIR ROE RECOMMENDATIONS. HOW**
9 **HAVE UTILITIES PERFORMED RELATIVE TO THE BROADER MARKET IN**
10 **RECENT MONTHS?**

11 A. Mr. Gorman argues that utilities’ “robust valuations” are an indication that utilities can
12 access equity capital at low cost.³⁰ Ms. Reno observes that utility stocks outperformed the
13 overall stock market between January and August 2022.³¹ While utility stocks caught up
14 to the broad market in the first half of 2022, that changed quickly in September and October
15 as utilities were one of the worst performing sectors of the S&P 500 in September and
16 continued to underperform the market in October. As noted in my direct testimony, utilities
17 often underperform the market in 12-month periods after top-decile monthly relative
18 returns for the sector.³² As shown in Figure 8 below (an update to Figure 5 from my direct
19 testimony), the S&P Utilities Index and The Southern Company’s stock price continue to
20 lag behind the broader market compared to pre-pandemic levels.

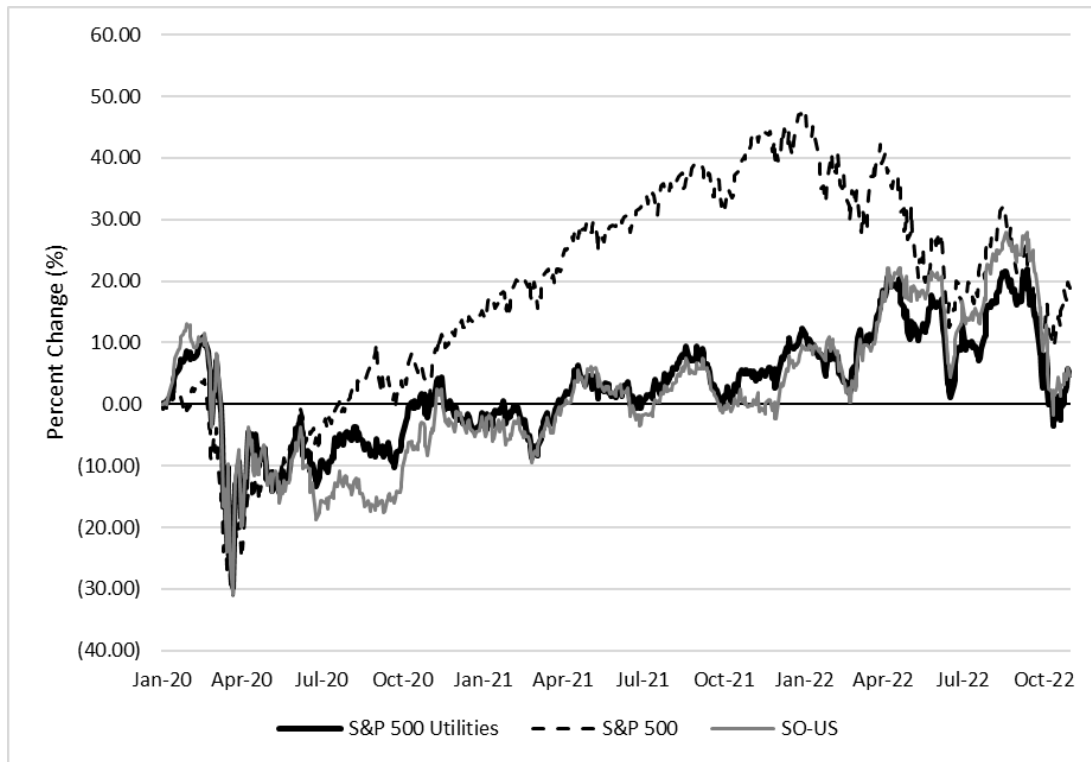
29 Blue Chip Financial Forecast, Vol. 41, Issue No. 11, November 1, 2022, at 14.

30 Direct Testimony of Michael P. Gorman, at 7-8.

31 Direct Testimony of Maureen L. Reno, at 14-15.

32 Direct Testimony of James M. Coyne, at 15-16.

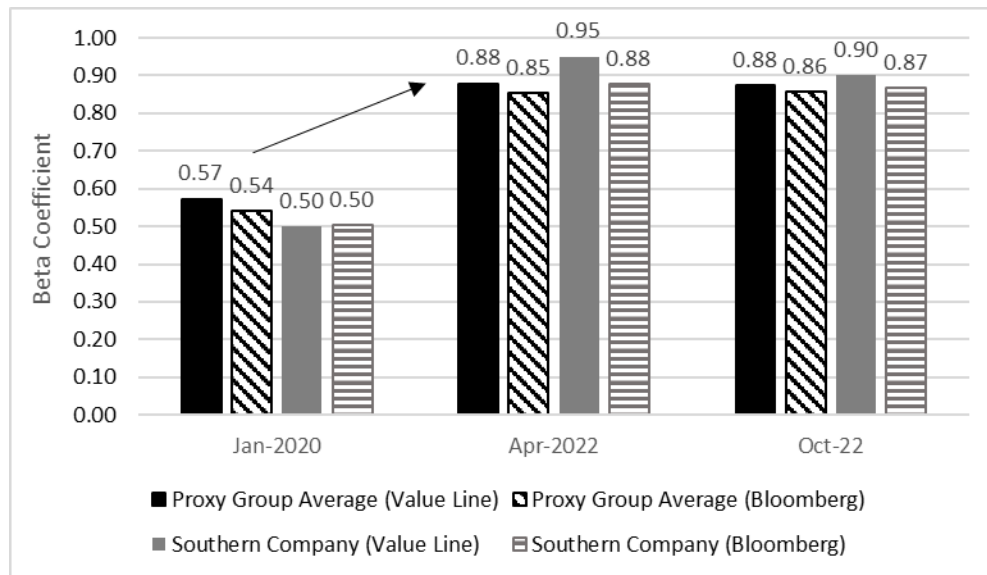
**Figure 8: Relative Performance of Utilities and the S&P 500,
January 2020 – October 2022³³**



As shown in Figure 9 below (an update to Figure 4 of my Direct Testimony), Beta coefficients for the proxy group and The Southern Company remain elevated.

³³ Source: S&P Capital IQ.

Figure 9: Beta Coefficients for Proxy Group and The Southern Company³⁴



Q. HAVE YOU FACTORED THESE CIRCUMSTANCES INTO YOUR ROE RECOMMENDATION FOR GEORGIA POWER AND, IF SO, WHAT CONCLUSIONS DO YOU DRAW?

A. Yes. Long-term interest rates have increased substantially since the historic lows of 2020 and are expected to continue to increase as the Federal Reserve unwinds its pandemic response measures and focuses on inflation. This supports the use of both current and forecast bond yields in the CAPM and Risk Premium models. These circumstances also reinforce the importance of considering the results of multiple models, as I have with the DCF, CAPM, Risk Premium, and Expected Earnings approaches. By contrast, several of the Intervenor Witnesses have focused on one or two models, leading to an unnecessarily narrow view, especially under current market conditions that impact the models differently. On balance, my updated review of the capital market environment continues to support my recommendation for an 11 percent ROE and 56 percent equity ratio and their consistency with the *Hope* and *Bluefield* standards.

³⁴ Value Line and Bloomberg as of October 31, 2022.

1 **IV. COST OF EQUITY ANALYSES**

2 **Q. DO THE INTERVENOR WITNESSES ACCEPT YOUR PROXY GROUP?**

3 A. Yes, the Intervenor Witnesses generally accept my proxy group as being reasonable.
4 However, Mr. Gorman excludes American Electric Power Company (“AEP”), due to the
5 pending sale of its Kentucky electric utility, and includes The Southern Company. As
6 explained in my direct testimony, I disagree with the inclusion of Georgia Power’s parent
7 company as it reflects circular logic.

8 **Q. IS AEP’S PENDING SALE OF KENTUCKY POWER COMPANY A**
9 **SIGNIFICANT TRANSACTION THAT WARRANTS AEP’S EXCLUSION FROM**
10 **THE PROXY GROUP?**

11 A. No, it is not. The primary reason to exclude companies on the basis of merger and
12 acquisition activity is because significant transactions can affect the market data (e.g., stock
13 prices) on which certain of the models rely. At the time the transaction was announced,
14 AEP had a market capitalization of \$42.23 billion; the Kentucky Power transaction is
15 valued at \$2.646 billion or only approximately 6.3 percent of AEP’s total market value at
16 the time the transaction was announced. Consequently, the transaction is not significant
17 enough to warrant AEP’s exclusion from the proxy group.

18 **A. DCF MODEL**

19 **Q. MS. RENO BASES HER ROE RECOMMENDATIONS ON THE RESULTS OF**
20 **HER DCF ANALYSIS, WHILE MR. GORMAN AND MR. ELLIS GIVE 50**
21 **PERCENT WEIGHT TO THEIR DCF MODEL ESTIMATES IN DETERMINING**
22 **THEIR ULTIMATE ROE RECOMMENDATIONS. DO YOU AGREE THAT IT IS**
23 **APPROPRIATE TO PLACE THIS DEGREE OF RELIANCE ON THE DCF**
24 **MODEL FOR A U.S. UTILITY?**

25 A. No, I do not. As discussed in my direct testimony, while many U.S. utility regulators have
26 used the DCF model to establish the authorized ROE, several regulators, including FERC,

1 have recognized the challenges associated with relying solely on the DCF to establish the
2 authorized ROE for regulated utilities in recent years.³⁵ For that reason, other federal and
3 state regulators have relied on the results of multiple methodologies both to test the
4 reasonableness of the DCF results and to establish a cost of equity that reflects investors'
5 required return on a going-forward basis.

6 **Q. PLEASE ELABORATE ON YOUR CONCERNS WITH THE DCF MODEL**
7 **UNDER CURRENT MARKET CONDITIONS.**

8 A. Although I have included the DCF model in my analyses, I have concerns with the ability
9 of the DCF model to produce reliable results under current market conditions. This concern
10 is amplified with an ROE analysis or recommendation relying exclusively on the DCF
11 model. As explained in my direct testimony, high utility valuations are expected to decline
12 as utilities underperform the broader market and, under these circumstances, the results of
13 the DCF model would understate the forward-looking cost of equity because the dividend
14 yield is calculated using historical average stock prices which do not fully reflect these
15 expectations.³⁶ This shift has already begun to occur.

16 Mr. Gorman observes the high valuations of electric utilities, referencing the higher than
17 average P/E ratios. However, he disregards the effect of those high valuations on the results
18 of the DCF model, in particular the dividend yield component. Exhibit __ (MPG-3) page 4
19 demonstrates the decline in the Value Line electric utility dividend yields over the past
20 decade, from 4.20 percent in 2012 to 3.36 percent in 2022. This indicates that investors are
21 paying more for a dollar of earnings from electric utilities than they did 10 years ago. As
22 interest rates increase from historic lows, these high valuations are likely to come under
23 pressure and decline. As noted earlier, utility stocks have underperformed the broad market
24 in September and October after outperforming earlier in 2022. As a result, my conclusion
25 is that the DCF model is understating the forward-looking cost of equity for regulated

35 Direct Testimony of James M. Coyne, at 28-29.

36 Direct Testimony of James M. Coyne, at 15-16.

1 utilities such as Georgia Power because the model is based on average historical stock
2 prices that are based on unsustainable valuation levels.

3 Mr. Ellis³⁷ regards high market-to-book (“M/B”) ratios as a sign that authorized ROEs for
4 regulated utilities are higher than the investor required cost of equity. To test this premise,
5 I performed an analysis that examines the correlation between government bond yields and
6 the market-to-book ratios for electric utilities since 1980, using data provided in
7 Exhibit__(MPG-15) and Exhibit__(MPG-18) to Mr. Gorman’s direct testimony. As shown
8 in Figure 10, the R^2 for this analysis is approximately 0.72, indicating a strong linear
9 relationship between M/B ratios and interest rates. This relationship indicates that utility
10 M/B ratios have increased not because authorized returns were higher than the true cost of
11 equity, but because interest rates on government bonds have steadily declined for the past
12 four decades. Low interest rates are favorable for capital-intensive industries such as
13 utilities, while increasing interest rates are not.

37 Direct Testimony of Mark E. Ellis, at 14-18.

Figure 10: Market-to-Book Ratios and Interest Rates



1. Growth Rates in the DCF Model

Q. PLEASE COMMENT ON THE INTERVENOR WITNESSES' USE OF GROWTH RATES IN THE DCF MODEL.

A. Mr. Gorman and Ms. Reno consider a variety of growth rates including projected earnings per share ("EPS"), dividends per share ("DPS"), and book value per share, as well as "sustainable" growth rates and projected GDP growth. As explained in my direct testimony, over the long term, dividend growth can only be sustained by earnings growth,³⁸ while dividend growth can depend on management decisions regarding the dividend payout ratio over the near-term which do not reflect the long-term growth prospects of the company.

I agree, however, with Mr. Gorman's and Ms. Reno's decision to essentially discard the results of their Constant Growth DCF analysis that apply sustainable growth rates. I note that their sustainable growth rate calculations rely on Value Line's projected ROE data for the proxy group companies. Those projected ROEs are substantially higher than the results

³⁸ Direct Testimony of James M. Coyne, at 26-27.

1 of the DCF model using sustainable growth rates presented by any of the Intervenor
2 Witnesses, and demonstrate the fact that investors are expecting to earn higher returns on
3 equity from the proxy group companies than what is shown by the DCF model using
4 “sustainable growth rates” calculated from the same source, Value Line. This is an inherent
5 inconsistency in their sustainable growth approach to the DCF.

6 **Q. MR. ELLIS EXPRESSES CONCERNS THAT ANALYSTS’ PROJECTED EPS**
7 **GROWTH RATES ARE “OPTIMISTIC,”³⁹ WHILE MR. GORMAN CLAIMS**
8 **THAT LONG-TERM GDP GROWTH SERVES AS A CAP ON LONG-TERM EPS**
9 **GROWTH RATES AND SUGGESTS THAT SHORT-TERM EPS GROWTH**
10 **RATES ARE TOO HIGH.⁴⁰ DO YOU SHARE THOSE CONCERNS ABOUT**
11 **ANALYSTS’ PROJECTED EPS GROWTH RATES?**

12 A. No, this is a familiar refrain, but unsubstantiated for utilities. The 2003 Global Analysts
13 Research Settlement (the “Global Settlement”) served to significantly reduce the bias
14 referred to by Mr. Ellis. In fact, the Global Settlement required financial institutions to
15 insulate investment banking business from the analysis business, prohibited analysts from
16 participating in “road shows,” and required the settling financial institutions to fund
17 independent third-party research.

18 A 2010 article in Financial Analysts Journal found that analyst forecast bias declined
19 significantly or disappeared entirely after the Global Settlement:

20 Introduced in 2002, the Global Settlement and related regulations had an
21 even bigger impact than Reg FD on analyst behavior. After the Global
22 Settlement, the mean forecast bias declined significantly, whereas the
23 median forecast bias essentially disappeared. Although disentangling the
24 impact of the Global Settlement from that of related rules and regulations
25 aimed at mitigating analysts’ conflicts of interest is impossible, forecast bias
26 clearly declined around the time the Global Settlement was announced.

39 Direct Testimony of Mark E. Ellis, at 36-37.

40 Direct Testimony of Michael P. Gorman, at 43-44.

1 These results suggest that the recent efforts of regulators have helped
2 neutralize analysts' conflicts of interest.⁴¹

3 In addition, analysts covering the common stock of the proxy companies certify that their
4 analyses and recommendations are not related, either directly or indirectly, to their
5 compensation. Thus, it is unclear why investors would assume that the proxy companies
6 are susceptible to a continuing upward bias in earnings projections, especially given the
7 fact that electric utilities operate in the mature stage of a stable industry with a very high
8 degree of financial transparency due to their regulation. Further, to the extent Mr. Ellis
9 believes that investors are well aware of these optimistic or biased growth rates, that
10 suggests that utility stock prices already reflect that information.

11 Likewise, actual earnings data belie Mr. Gorman's position that projected GDP growth
12 represents a cap on long-term EPS growth. The suggestion that equity earnings are limited
13 by future growth in GDP may hold for aggregate corporate earnings in a closed economy
14 but these are not realistic assumptions for an individual firm nor for utilities in general.⁴²
15 To illustrate this point, I have compared the actual historical EPS and dividend per share
16 ("DPS") growth rates (to the extent data was available through Value Line) of all U.S.
17 electric utilities and the companies in my proxy group from 2011-2021 to historical and
18 projected GDP growth rates from Blue Chip, the Energy Information Administration, and
19 the Social Security Administration. The results are shown in Figure 11 below.

41 Armen Hovakimian and Ekkachai Saenyasiri, *Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation*, Financial Analysts Journal, Volume 66, Number 4, July/August 2010 at 195.

42 See MSCI Barra Research Bulletin, *Is There a Link Between GDP Growth and Equity Returns?* (May 2010).

Figure 11: Analysis of EPS, DPS, and GDP Growth Rates⁴³

		[1] <i>Historical</i> 2011 - 2021		[2] <i>Historical</i> 2011 - 2021		[3] <i>Projected</i>	% Historical Difference		% Historical Multiple	
	No. of Companies	EPS Growth	DPS Growth	GDP Growth	GDP Growth		EPS vs GDP	DPS vs GDP	EPS vs GDP	DPS vs GDP
U.S. All Electric Companies [4]	36	4.37%	5.57%	4.15%	4.24%		0.23%	1.42%	1.1	1.3
GPC Proxy Group	14	5.08%	6.13%	4.15%	4.24%		0.93%	1.98%	1.2	1.5
AVERAGE		4.73%	5.85%	4.15%	4.24%		0.58%	1.70%	1.1	1.4

As shown in Figure 11, the EPS and DPS growth rates of utilities can, and do, exceed GDP growth for sustained periods. Specifically, for the Georgia Power proxy group, historical EPS has exceeded historical GDP growth by 0.93 percent from 2011-2021 and historical DPS has exceeded historical GDP growth by 1.98 percent over the same period. This rate of growth is 10 to 40 percent greater than GDP over this same period. My conclusion is that it is not unreasonable to rely on analyst EPS growth projections, as I and other experts commonly do, just because they exceed GDP growth.

I do not share Mr. Ellis' and Mr. Gorman's concern that analysts' projected EPS growth rates are too high. Mr. Gorman ultimately relies on analysts' projected EPS growth rates in his Constant Growth DCF model, which forms the lower boundary of his recommended ROE range, effectively discarding the results of his Multi-Stage DCF model results that include projected GDP growth in the terminal stage. The average EPS growth rate that Mr. Gorman uses in his Constant Growth DCF model (5.45 percent) is consistent with the average EPS growth rates used in my Constant Growth DCF analysis (5.61 percent) and is more reasonable. His over-reliance on this result, however, unduly forces his overall ROE recommendation downward.

⁴³ Sources: Value Line, Blue Chip Financial Forecasts, Bureau of Economic Analysis, US Energy Information Administration,

1 **Q. PLEASE DESCRIBE THE ISSUE WITH THE APPLICATION OF SUSTAINABLE**
2 **GROWTH OR RETENTION GROWTH IN THE CONSTANT GROWTH DCF**
3 **MODEL.**

4 A. The sustainable growth rate or retention growth rate calculation assumes that future
5 earnings will increase as the retention ratio increases. However, this relationship may not
6 hold for a given company based on management decisions associated with the dividend
7 payout rate. This conclusion is supported by two articles published in the *Financial*
8 *Analysts Journal* that discussed the theory that high dividend payouts (*i.e.*, low retention
9 ratios) are associated with low future earnings growth.⁴⁴ Each of those articles cited to a
10 2003 study by Arnott and Asness⁴⁵ that found, over the course of 130 years of data, future
11 earnings growth is associated with high, rather than low payout ratios.⁴⁶ Specifically,
12 Arnott and Asness concluded:

13 Unlike optimistic new-paradigm advocates, we found that low payout ratios
14 (high retention rates) historically precede low earnings growth. This
15 relationship is statistically strong and robust. We found that the empirical
16 facts conform to a world in which managers possess private information
17 that causes them to pay out a large share of earnings when they are
18 optimistic that dividend cuts will not be necessary and to pay out a small
19 share when they are pessimistic, perhaps so that they can be confident of
20 maintaining the dividend payouts. Alternatively, the facts also fit a world in
21 which low payout ratios lead to, or come with, inefficient empire building
22 and the funding of less than-ideal projects and investments, leading to poor
23 subsequent growth, whereas high payout ratios lead to more carefully
24 chosen projects. The empire-building story also fits the initial
25 macroeconomic evidence quite well. At this point, these explanations are
26 conjectures; more work on discriminating among competing stories is
27 appropriate.⁴⁷

44 Ping Zhou, William Ruland, *Dividend Payout and Future Earnings Growth*, *Financial Analysts Journal*, Vol. 62, No. 3, 2006. See also Owain ap Gwilym, James Seaton, Karina Suddason, Stephen Thomas, *International Evidence on the Payout Ratio, Earnings, Dividends and Returns*, *Financial Analysts Journal*, Vol. 62, No. 1, 2006.

45 Robert Arnott, Clifford Asness, *Surprise: Higher Dividends = Higher Earnings Growth*, *Financial Analysts Journal*, Vol. 59, No. 1, January/February 2003.

46 Since the payout ratio is the inverse of the retention ratio, the authors found that future earnings growth is negatively related to the retention ratio.

47 Robert Arnott, Clifford Asness, *Surprise: Higher Dividends = Higher Earnings Growth*, *Financial Analysts Journal*, Vol. 59, No. 1, January/February 2003.

1 Given that all three studies found that there is a negative relationship between earnings
2 growth and retention ratios, the application of retention growth rates in the DCF model is
3 not appropriate.

4 2. Multi-Stage DCF Approach

5 **Q. MR. GORMAN AND MR. ELLIS HAVE ALSO PRESENTED THE RESULTS OF**
6 **A MULTI-STAGE DCF MODEL.⁴⁸ DO YOU AGREE THAT THE RESULTS AND**
7 **WEIGHT PLACED ON THOSE ANALYSES ARE REASONABLE?**

8 A. No, I do not. Mr. Gorman presents the results of a Multi-Stage DCF analysis but elects not
9 to rely on those results in setting his range or recommendation for Georgia Power,
10 presumably because he views the results as being too low.⁴⁹ Mr. Ellis also performs a
11 Multi-Stage DCF model, but unlike Mr. Gorman, he relies on those results for his ROE
12 recommendation, even though his Multi-Stage DCF result of 5.97 percent is more than 450
13 basis points below Georgia Power's current authorized ROE and significantly below any
14 ROE authorized for any electric utility in at least the last 40 years.

15 Mr. Ellis's use of an inflation rate as a proxy for earnings growth has no reasonable basis
16 of support, as he has provided no evidence that investors would accept growth in perpetuity
17 that tracks inflation. There are many investment alternatives available that offer more
18 attractive growth and return potential. As noted earlier, utility bond yields are currently
19 offering returns comparable to or higher than Mr. Ellis's DCF-based cost of equity
20 recommendation. No investor would commit capital to an equity investment if they can
21 receive an equal or higher return from a safer debt investment that has a senior claim on
22 cash flow.

48 See, for example, Direct Testimony of Michael P. Gorman, at 41-47, Direct Testimony of Mark E. Ellis, at 46-50.

49 Direct Testimony of Michael P. Gorman, at 47.

1 **B. CAPM ANALYSIS**

2 **Q. BEFORE RESPONDING TO THE INTERVENOR WITNESSES' CRITICISMS OF**
3 **YOUR CAPM ANALYSIS, ARE THERE AREAS OF AGREEMENT WITH**
4 **RESPECT TO YOUR RESPECTIVE CAPM ANALYSES?**

5 A. Yes, there are. First, Mr. Gorman, Ms. LaConte, Ms. Reno, and Mr. Ellis, and I agree that
6 the 30-year Treasury bond yield is appropriate to use as the risk-free rate.⁵⁰ Second,
7 although certain of the Intervenor Witnesses disagree with the use of projected interest
8 rates, Mr. Gorman includes a projection of the 30-year Treasury in his analysis, suggesting
9 he believes that the current rate underestimates the expected risk-free rate.⁵¹ Third, Mr.
10 Gorman, Ms. Reno, and Ms. LaConte each rely on Blume-adjusted Beta coefficients
11 reported by Value Line.⁵²

12 **Q. ARE CAPM RESULTS DEVELOPED BY CERTAIN INTERVENOR WITNESSES**
13 **REASONABLE?**

14 A. No, they are not. In particular, Mr. Ellis' CAPM result (5.41 percent) is well below the
15 lowest authorized ROE for any electric utility in the last 40 years.⁵³ Estimates as low as
16 5.41 percent are nearly 100 basis points *below* the reported cost of debt for utilities in
17 October 2022.⁵⁴ Debt investors require a return commensurate with the risk that the
18 company will fail to meet that obligation. However, equity investors bear the residual risk
19 associated with ownership, and have a claim on cash flows only after debt holders are paid.
20 As such, equity holders bear greater risk and therefore require a higher return. The fact that

50 Direct Testimony of Michael P. Gorman, at 54; Direct Testimony of Billie S. LaConte at 8; Direct Testimony of Maureen L. Reno at 35; Direct Testimony of Mark E. Ellis, at 68.

51 Direct Testimony of Michael P. Gorman, at 54.

52 Direct Testimony of Michael P. Gorman, at 54-55; Direct Testimony of Maureen L. Reno, at 38-39; Direct Testimony of Billie S. LaConte, at 8.

53 Source: S&P Capital IQ Pro, Regulatory Research Associates.

54 The Moody's Utility Bond Index for Baa-rated Utility debt was as 6.34 percent as of October 31, 2022 (Source: Bloomberg Professional).

1 Mr. Ellis' CAPM analysis produces a result that is well below debt returns demonstrates
2 his inputs are unreasonable and his results should be disregarded.

3 **1. Risk-free rate**

4 **Q. MR. ELLIS QUESTIONS THE ACCURACY OF INTEREST RATE FORECASTS**
5 **AND OBJECTS TO YOUR USE OF A PROJECTED 30-YEAR TREASURY BOND**
6 **YIELD AS THE RISK-FREE RATE.⁵⁵ HOW DO YOU RESPOND?**

7 A. As explained earlier in this rebuttal testimony and in my direct testimony, I believe the use
8 of projected 30-year Treasury bond yields as the risk-free rate in the CAPM analysis is
9 appropriate because interest rates are expected to continue increasing as the Federal
10 Reserve unwinds its balance sheet and tightens monetary policy. Notably, both the current
11 and projected risk-free rates presented in my direct testimony (2.72 percent and 3.40
12 percent, respectively) are well below the 30-day average 30-year Treasury yield of 3.92
13 percent as of October 31, 2022. In addition, I do not share Mr. Ellis' concerns with the
14 accuracy of projected bond yields. This is because the cost of equity depends on what
15 investors expect, not what actually happens.⁵⁶ Nonetheless Mr. Ellis has not presented any
16 evidence that current interest rates are any more accurate at predicting future interest rates
17 *in the long-term.*

18 Further, even though I do not agree with the exclusive reliance on the current average
19 Treasury bond yield as the risk-free rate, I note using current bond yields in the CAPM
20 model produces results (shown in Exhibit JMC-5.2) well above the DCF model results and
21 much higher than the CAPM results put forth by Mr. Gorman, Ms. Reno, Ms. LaConte,
22 and Mr. Ellis. My conclusion is that it is reasonable and appropriate to use the projected
23 30-year Treasury bond yield as the risk-free rate.

55 See, Direct Testimony of Mark E. Ellis, at 51-55.

56 See, 147 FERC ¶ 61,234, Docket No. EL11-66-001, Opinion No. 531 Order on Initial Decision, at para 88 (June 19, 2014).

1 **Q. WHAT IS YOUR RESPONSE TO MR. GORMAN’S CRITICISM THAT YOUR**
2 **PROJECTED LONG-TERM RISK-FREE RATE IS “UNREASONABLE”?**⁵⁷

3 A. Mr. Gorman’s criticism is puzzling. His CAPM estimate of 9.88 percent relied upon to
4 develop his recommended ROE range uses a *higher* projected risk-free rate of 3.60 percent
5 from Blue Chip published on August 1, 2022 than my 3.40 percent projected risk-free rate
6 that he criticizes. If his position is that his higher projected long-term risk-free rate of 3.60
7 percent is more current than the risk-free rates I used in my direct testimony in the current
8 market environment, I agree. Further, projected risk-free rates align with Georgia Power’s
9 2023 test year and Alternative Rate Plan that would be effective through 2025, contrary to
10 Mr. Gorman’s position.

11 **2. Beta**

12 **Q. HOW DO THE INTERVENOR WITNESSES ESTIMATE BETA?**

13 A. As discussed above, Ms. LaConte and Ms. Reno each rely on current Value Line Beta
14 coefficients.⁵⁸ Mr. Gorman considered current Value Line Beta coefficients before
15 ultimately relying on a historical quarterly average of Value Line Beta coefficients between
16 Q3 2014 and Q2 2022.⁵⁹ Mr. Ellis relies on Zacks and Yahoo! Finance estimates of Beta
17 that are calculated based on monthly returns, rather than the weekly convention used by
18 Value Line and that I use with Bloomberg.

19 **Q. MR. GORMAN OBSERVES THAT CURRENT BETA COEFFICIENTS FROM**
20 **VALUE LINE ARE HIGHER THAN THE HISTORICAL AVERAGE FOR THE**
21 **ELECTRIC UTILITY INDUSTRY.⁶⁰ DO YOU VIEW THIS AS A REASON TO**
22 **ADJUST THE CURRENT BETA COEFFICIENTS?**

57 Direct Testimony of Michael P. Gorman, at 73.

58 Direct Testimony of Billie S. LaConte, at 8; Direct Testimony of Maureen L. Reno, at 38.

59 Direct Testimony of Michael P. Gorman, at 57.

60 Direct Testimony of Direct Testimony of Michael P. Gorman, at 55-57.

1 A. No, I do not. Beta is the measure of relative risk in the CAPM analysis. The utility industry
2 has typically had lower than average Beta coefficients because utilities generally tend to
3 be less volatile than the broad market. However, as discussed in my direct testimony,⁶¹ that
4 was not the case during the market dislocation that occurred in response to the COVID-19
5 pandemic. Five-year Beta coefficients from both Value Line and Bloomberg increased
6 substantially in February and March 2020 to levels not seen since the financial crisis of
7 2008/2009 and have remained at those elevated levels ever since.⁶² In my view, there is no
8 reason to use the longer-term average Beta coefficients, as suggested by Mr. Gorman. I
9 have used Value Line and Bloomberg Beta coefficients calculated using five years of
10 weekly return data against a broad market index (either the S&P 500 or the NYSE
11 Composite). This five-year period pre-dates the COVID-19 period by 2.5 years, which
12 suggests that the proxy group Beta coefficients are being affected by factors other than the
13 pandemic.

14 As discussed in my direct testimony, electric utilities have not served as a safe haven for
15 investors during the recent economic downturn.⁶³ According to Mr. Gorman's
16 Exhibit__(MPG-20) pages 2-5, Beta coefficients for the proxy group and the electric and
17 natural gas utilities have stabilized at elevated levels since Q3 2020, contradicting Mr.
18 Gorman's position that utilities' higher Beta coefficients are the result of just two
19 anomalous months in March and April 2020.⁶⁴ In my opinion, this shift may also be
20 attributable to the market's recognition of the complex challenges facing the industry in
21 response to climate change, transitioning to a lower carbon generation mix, grid
22 modernization, and shifting consumer preferences.

23 Further, I do not agree with Mr. Ellis' concerns with Value Line's methodology for
24 calculating Beta coefficients, including the time period over which Betas are calculated,
25 the market index, and the Blume adjustment. I note that Beta is a measure of relative risk

61 Direct Testimony of James M. Coyne, at 13-14.

62 *Ibid.*, at 32-33.

63 *Ibid.*, at 13-14.

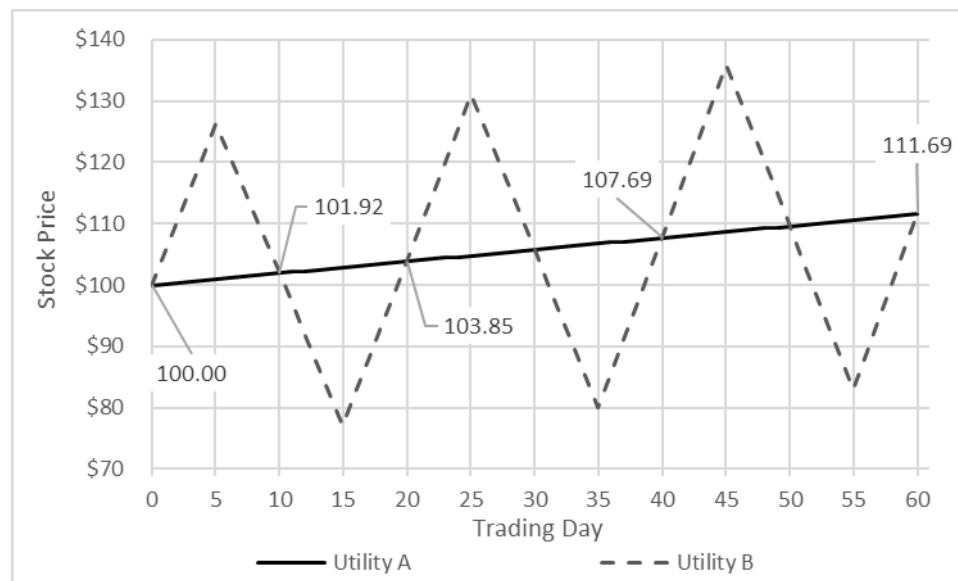
64 Direct Testimony of Michael P. Gorman, at 55.

in the CAPM analysis. While utilities have underperformed the broader market since January 2020, Beta coefficients demonstrate that utilities have traded more in line with the broad market than they have historically, indicating that utility investors recognize the structural shifts affecting the industry.

Q. WHAT IS YOUR RESPONSE TO MR. ELLIS' USE OF MONTHLY BETAS REPORTED BY YAHOO! FINANCE AND ZACKS?

A. By their nature, Beta coefficients calculated using monthly returns do not capture intra-month return volatility and could lead one to conclude utility stock returns are more stable than they actually are. Consider, for example, stock prices for two utilities – Utility A and Utility B – over a 60-trading day period (roughly three calendar months), illustrated in Figure 12 below. Both utilities start trading at a price of \$100 per share. Both utilities report a stock price return of 11.69 percent at the end of three months. At the end of every month (the 20th trading day), both stocks have the same price. However, Utility B's stock price is clearly more volatile (and therefore riskier) than Utility A's.

Figure 12: Illustrative Example of Weekly vs. Monthly Stock Volatility



If the Beta coefficient for Utility B was calculated using monthly returns, it would not capture intra-month stock price volatility and Utility B's Beta coefficient would be the

1 same as Utility A's. On the other hand, if the Beta coefficients were calculated using
2 weekly returns (every five trading days), Utility B's Beta coefficient would be higher than
3 Utility A's, all else equal, better reflecting its higher volatility. In other words, Mr. Ellis
4 suggests that the Commission should ignore evidence of increasing volatility and risk for
5 utility companies, and the proxy group specifically.

6 3. Market Risk Premium

7 **Q. THE INTERVENOR WITNESSES CHALLENGE THE FORWARD-LOOKING**
8 **MARKET RISK PREMIUM YOU USED IN YOUR CAPM ANALYSIS.⁶⁵ CAN**
9 **YOU PLEASE RESPOND TO THEIR CONCERNS?**

10 A. The use of a forward-looking or projected market risk premium ("MRP") is appropriate
11 because the historical average market risk premium does not reflect the inverse relationship
12 between interest rates and the equity risk premium. The Ibbotson data used to calculate the
13 historical MRP of 7.46 percent indicates that the long-term average return on large
14 company stocks from 1926-2021 was 12.33 percent, while the average income-only return
15 on government bonds was 4.87 percent over the same period.⁶⁶ It is therefore not
16 reasonable to use the historical MRP when the current average yield on the 30-year
17 Treasury bond is *lower* than the bond yield used to calculate the historical MRP. With
18 interest rates at these levels, the forward-looking MRP should be *higher* than 7.46 percent.

19 Second, the method I have used to calculate the forward-looking MRP is similar to the
20 methodology used by FERC in Opinion No. 531-B.⁶⁷ Specifically, the forward-looking
21 MRP in my CAPM analysis is derived by calculating the expected total return for the
22 companies in the S&P 500 Index less the projected risk-free rate. Ms. LaConte adjusts my
23 forward-looking MRP to exclude companies with negative growth rates and growth rates
24 above 20 percent. However, when investors purchase the S&P 500 Index or a mutual fund

⁶⁵ Direct Testimony of Michael P. Gorman, at 71-72; Direct Testimony of Billie S. LaConte, at 7-8; Direct Testimony of Maureen L. Reno, at 37-38; Direct Testimony of Mark E. Ellis, at 67-68.

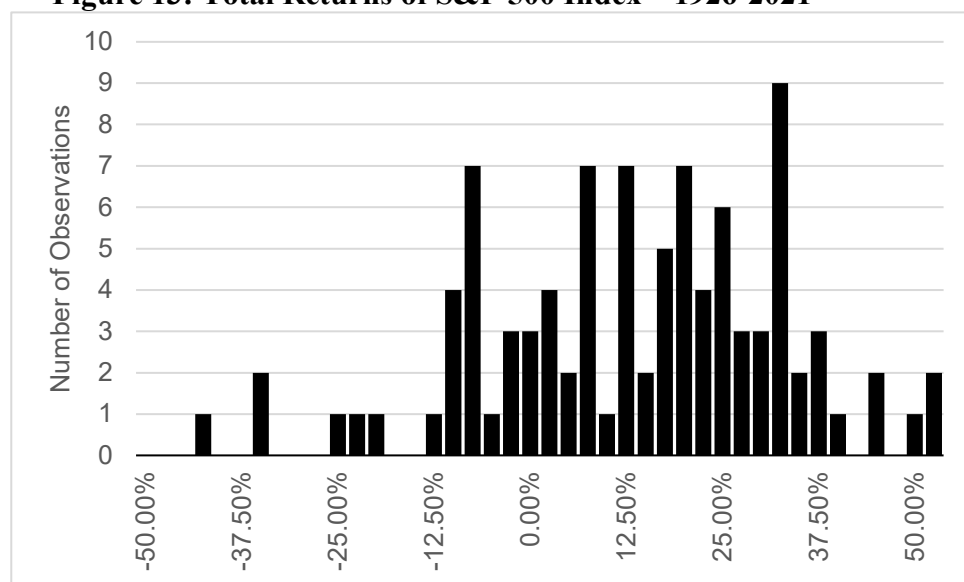
⁶⁶ Source: Kroll, 2022 SBBI Yearbook, at Appendix A-1, A-7.

⁶⁷ See *MISO Transmission Owners, et al. v. FERC*, No. 16-1325 (Aug. 9, 2022) (slip op.) at 17-24 (upholding FERC's CAPM methodology).

or exchange traded fund that mirrors the S&P 500 Index, their total return is based on the returns for all 500 companies in the S&P 500 Index, not only those companies with positive EPS growth rates or growth rates less than 20 percent. Further, my MRP calculation is internally consistent because the Betas used in my CAPM analysis are calculated against all companies in the S&P 500 Index or the NYSE Composite Index, not just against those companies that have positive growth rates or growth rates less than 20 percent.

The Intervenor Witnesses argue that the total market return used in my forward-looking MRP calculation are not reasonable. To assess their reasonableness, I analyzed the annual performance of the S&P 500 from 1926-2021. As shown in Figure 13 below, the actual return on the S&P 500 Index has exceeded 15 percent in 50 percent (48 out of 96) of the years from 1926-2021. These data demonstrate that actual total returns for the broad market greater than 15 percent are not uncommon.

Figure 13: Total Returns of S&P 500 Index – 1926-2021⁶⁸



Q. MR. GORMAN, MS. LACONTE, AND MS. RENO APPLY MARKET RISK PREMIA BASED ON HISTORICAL DATA.⁶⁹ HOW DO YOU RESPOND?

⁶⁸ Source: Kroll, 2022 SBBI Yearbook, Appendix A-1.

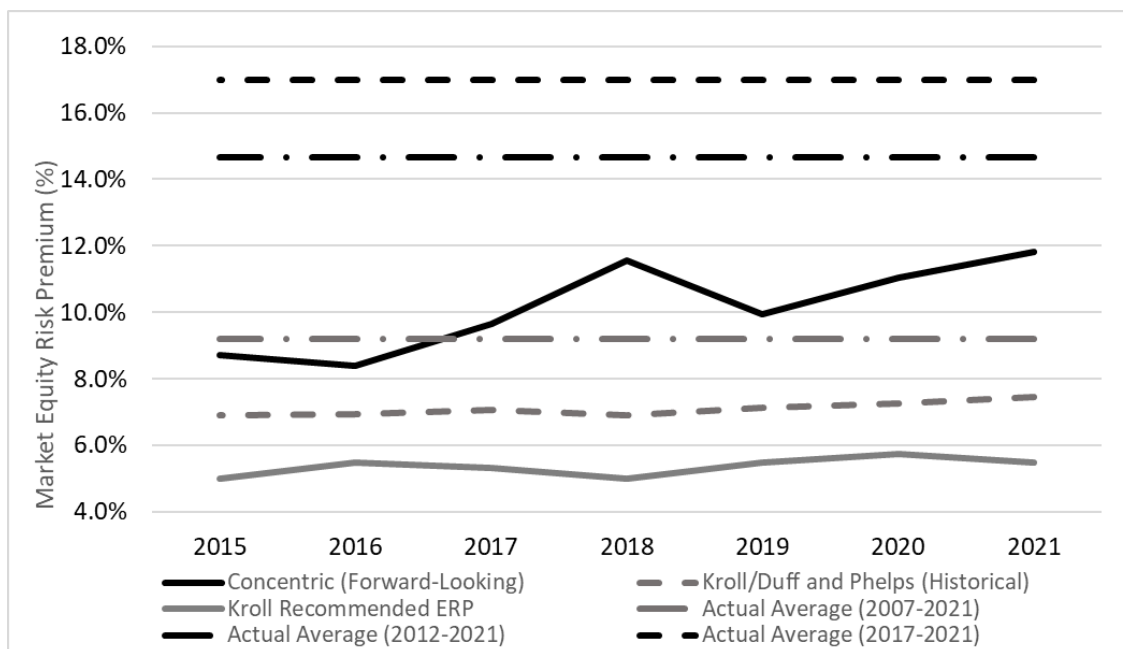
⁶⁹ Direct Testimony of Michael P. Gorman, at 57-56; Direct Testimony of Billie S. LaConte, at 8; Direct Testimony of Maureen L. Reno, at 36-37.

1 A. As explained earlier, the use of a historical market risk premium is not appropriate under
2 current market conditions because it does not reflect the inverse relationship between
3 interest rates and the equity risk premium, nor the earnings growth for today's S&P 500
4 companies. When the current average yield on U.S. Treasury bonds is *below* the long-term
5 historical average yield, it is reasonable to expect that the MRP would be *above* the
6 historical average market risk premium. Consequently, the long-term average historical
7 market risk premium would be appropriate only if the expected risk-free rate was similar
8 to the long-term historical risk-free rate. Further, equity market returns calculated over the
9 last century do not represent the growth available today to U.S. companies from
10 international markets and the roles of technology and innovation in driving earnings
11 growth.

12 **Q. DO YOU AGREE WITH MR. GORMAN AND MS. RENO'S REFERENCE TO**
13 **KROLL'S RECOMMENDED EQUITY RISK PREMIUM OF 5.50 PERCENT?**

14 A. No, I do not. As a case in point, Figure 14 below demonstrates just how far off Kroll's
15 recommended market equity risk premium has been over the past seven years in relation
16 to the forward-looking approach I have used. Kroll's recommended market equity risk
17 premium has substantially underestimated actual market performance over several
18 averaging periods.

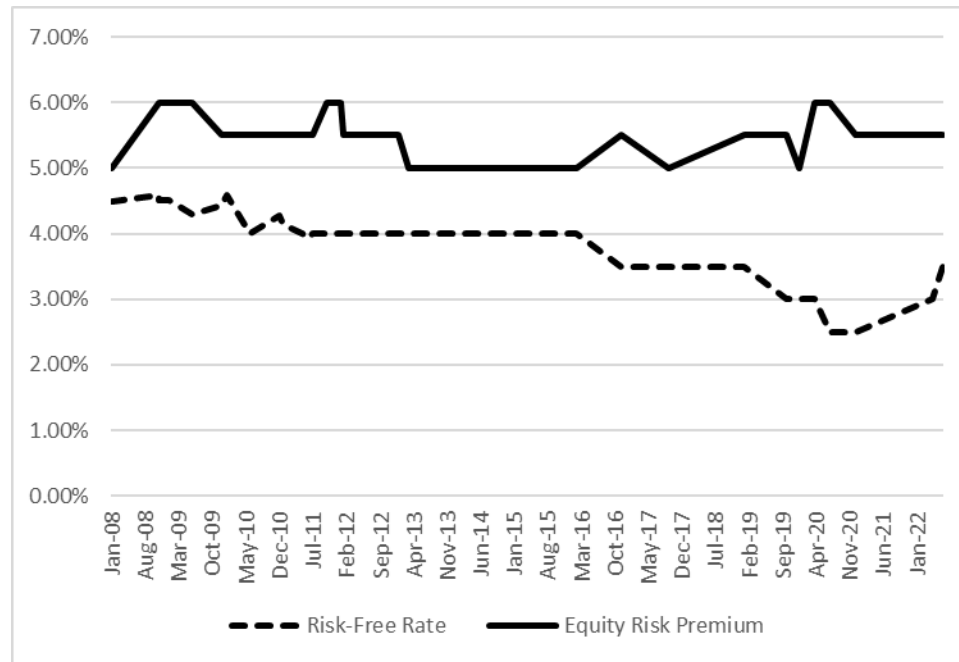
Figure 14: Market Equity Risk Premium Methods



Further, it is not clear that Kroll develops its recommended market equity risk premium in relation to its risk-free rate. Because the market equity risk premium is a function of the market return and the risk-free rate at a point in time, the market equity risk premium is related to the risk-free rate (as explained earlier, there is an inverse relationship between the two). As Figure 15 below shows, there is no apparent relationship⁷⁰ between Kroll's recommended market equity risk premium and risk-free rate.

⁷⁰ The R-square between the Kroll's "normalized" risk-free rate and recommended equity risk premium between 2008-2022 is 0.09 percent and statistically insignificant.

**Figure 15: Kroll's Recommended Market Equity Risk Premium and Risk-Free Rate
(2008-2022)⁷¹**



Q. WHAT IS YOUR CONCLUSION WITH REGARD TO THE CAPM?

A. My conclusion is that using reasonable forward-looking inputs for the risk-free rate and MRP, along with current Betas from Value Line and Bloomberg, the CAPM is producing results that should be considered along with the results from the DCF, Risk Premium, and Expected Earnings models.

C. RISK PREMIUM MODEL

Q. THE INTERVENOR WITNESSES CHALLENGE THE USE OF A RISK PREMIUM MODEL SUCH AS THE ONE YOU HAVE PRESENTED, OR THEY CONTEND THAT YOUR APPLICATION OF THE RISK PREMIUM MODEL IS NOT REASONABLE.⁷² HOW DO YOU RESPOND TO THEIR CONCERNS?

⁷¹ Kroll, 2022 Cost of Capital Navigator.

⁷² See, e.g., Testimony of Michael P. Gorman, at 74-76; Direct Testimony of Billie S. LaConte, at 10-11; Direct Testimony of Maureen L. Reno, at 40-41; and Direct Testimony of Mark E. Ellis, at 3, 28-32.

1 A. Mr. Gorman expresses several concerns with my Risk Premium analysis, including: (1) he
2 disputes the inverse relationship between interest rates and risk premia; (2) he claims that,
3 while academic studies have shown that in the past there was such an inverse relationship,
4 the relationship has changed over time, particularly since interest rate volatility is not as
5 extreme as it was in the 1980s; and (3) he contends that I have ignored investment risk
6 differentials in my regression analyses, and that my adjustment to the equity risk premium
7 is based exclusively on changes in nominal interest rates.⁷³

8 In response to Mr. Gorman's first concern, there is a large body of research in addition to
9 my own statistical analyses that supports the inverse relationship between interest rates and
10 equity risk premia, including the March 1998 article published by Dr. S. Keith Berry, which
11 came to similar conclusions regarding the inverse relationship between interest rates and
12 the risk premia.⁷⁴ Several other studies were published after those that Mr. Gorman cites
13 as evidence that this inverse relationship is a relic of the 1980s. As summarized in Dr.
14 Roger Morin's *New Regulatory Finance*, two of these studies were published in 2005,
15 demonstrating that the inverse relationship between interest rates and the equity risk
16 premium are contemporary concepts in finance:

17 Published studies by Brigham, Shome, and Vinson (1985), Harris (1986),
18 Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok
19 (1983), Morin (2005), and McShane (2005), and others demonstrate that,
20 beginning in 1980, risk premiums varied inversely with the level of interest
21 rates—rising when rates fell and declining when interest rates rose. The
22 reason for this relationship is that when interest rates rise, bondholders
23 suffer a capital loss. This is referred to as interest rate risk.... Conversely in
24 low interest rate environments, when bondholders' interest rate fears
25 subside and shareholders' fears of loss of earning power dominate, the risk
26 differential will widen and hence the risk premium will increase.⁷⁵

73 Direct Testimony of Michael P. Gorman, at 74-76.

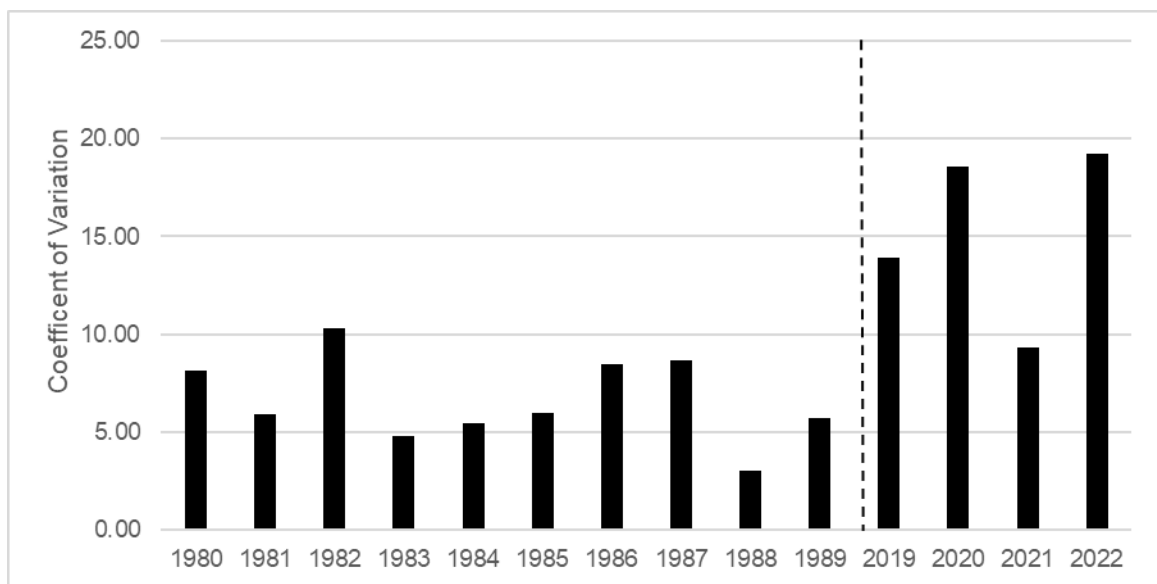
74 See e.g., S. Keith Berry, *Interest Rate Risk and Utility Risk Premia during 1982-93*, Managerial and Decision Economics, Vol. 19, No. 2 (March, 1998), in which the author used a methodology similar to the regression approach described below, including using allowed ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates.

75 Morin, Roger A., *New Regulatory Finance*, Public Utilities Reports, Inc. (2006), at 128.

Furthermore, my Risk Premium analysis has an R^2 of approximately 0.84, which indicates that there is a high degree of correlation between the observed equity risk premium and changes in interest rates.

With regard to Mr. Gorman's statement that interest rate volatility was more extreme in the 1980s than it is today, I conducted an analysis that compares the volatility in 30-year Treasury bond yields in each year during the 1980s to the volatility from 2019 to present. As shown in Figure 16, the relative standard deviation of Treasury bond yields is substantially higher in 2022 than it was during any year in the 1980s, indicating that interest rate volatility is higher in recent years than it was in the 1980s, and has been higher since 2019 than all but one year during the 1980s (i.e., 1982).

Figure 16: Treasury Bond Yield Volatility⁷⁶



In response to Mr. Gorman's third concern, he contends that I have ignored investment risk differentials in my regression analyses, and that my adjustment to the equity risk premium is based exclusively on changes in nominal interest rates. I agree that my analysis is based solely on the relationship to interest rates, as is Mr. Gorman's Risk Premium analysis. Mr. Gorman's Risk Premium analysis also does not consider any other variables except average

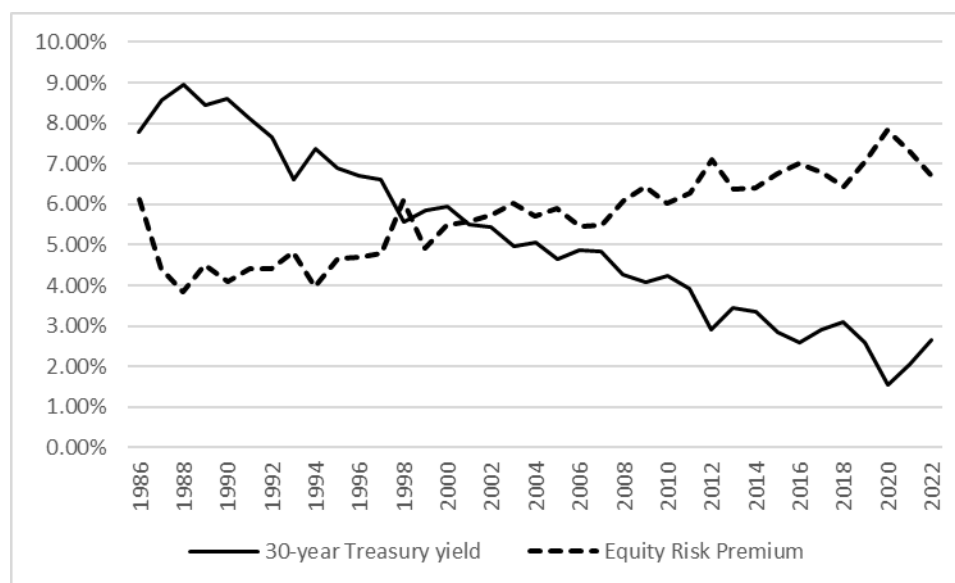
⁷⁶ Source: Bloomberg Professional.

1 authorized ROEs and bond yields. In my analysis, with an R^2 of 0.84, the relationship to
2 interest rates accounts for 82 percent of the change in awarded ROEs, which is quite strong.
3 In addition, the inclusion of 682 rate cases over a 30-year period provides a broad
4 perspective on case-specific issues. To the extent that shifts in industry risk are left out of
5 this equation, the recent increases in utility betas would suggest that the Risk Premium
6 results are biased downwards, and would likely understate the cost of equity. This
7 relationship is picked up directly, however, in the CAPM model, and these results are
8 meaningfully higher. Therefore, I believe the model is useful as a method to estimate the
9 cost of equity for electric utilities like Georgia Power, along with the results from the DCF,
10 CAPM, and Expected Earnings models.

11 **Q. DOES MR. GORMAN'S RISK PREMIUM ANALYSIS SUPPORT THE INVERSE**
12 **RELATIONSHIP BETWEEN THE EQUITY RISK PREMIUM AND BOND**
13 **YIELDS?**

14 **A.** Yes, it does. Mr. Gorman's Risk Premium analysis is conceptually similar to mine in that
15 he calculates the risk premium as the difference between authorized ROEs and Treasury
16 bond yields (as well as utility bond yields). As Figure 17 below shows, Mr. Gorman's
17 annual 30-year Treasury bond yield and indicated risk premium data in Exhibit__ (MPG-
18 16) show a strong negative, inverse relationship.

Figure 17: Mr. Gorman's Treasury Bond Yield and Indicated Risk Premium⁷⁷



Q. MS. LACONTE ADJUSTS YOUR RISK PREMIUM ANALYSIS TO COMBINE THE LONG-TERM AVERAGE EQUITY RISK PREMIUM OF 6.06 PERCENT WITH YOUR PROJECTED 30-YEAR TREASURY BOND YIELD. IS HER ADJUSTMENT APPROPRIATE?

A. No, it is not. The risk premium model is designed to adjust the risk premium for any given level of bond yield, based on the historical relationship between the two variables over the last 30 years. Adding the long-term average to a current or projected bond yield does not appropriately reflect the statistical relationship between the equity risk premium and 30-year Treasury bond yield. As noted earlier in my discussion of the market risk premium in the CAPM, the equity risk premium and bond yields are inversely related. The only time the historical average equity risk premium is appropriate is when the current or projected bond yield is approximately equal to the historical average bond yield. Ms. LaConte's adjustment to my Risk Premium analysis is inappropriate and should be rejected.

⁷⁷ Exhibit__(MPG-16).

1 **D. EXPECTED EARNINGS ANALYSIS**

2 **Q. BEFORE RESPONDING TO THE CRITICISMS OF YOUR EXPECTED**
3 **EARNINGS ANALYSIS, DO ANY OF THE INTERVENOR WITNESSES**
4 **PERFORM A SIMILAR ANALYSIS?**

5 A. Yes, Ms. Reno's Comparable Earnings Model ("CEM") reviews historical and forecasted
6 earned returns on book value and market-to-book ratios for the same proxy group of
7 companies that I use. Her 2025-2027 proxy group projected CEM results of 10.50 percent
8 to 10.86 percent are reasonably consistent with my Expected Earnings results presented in
9 Exhibit JMC-7 that range from 11.03 (mean) to 11.08 percent (median). However, Ms.
10 Reno does not give these results any weight in developing her 9.47 percent
11 recommendation, which forces her overall ROE recommendation downward.

12 **Q. PLEASE SUMMARIZE THE INTERVENOR WITNESSES' POSITIONS WITH**
13 **THE USE OF AN EXPECTED EARNINGS ANALYSIS TO ESTIMATE THE**
14 **COST OF EQUITY FOR GEORGIA POWER IN THIS PROCEEDING.⁷⁸**

15 A. Mr. Gorman, Mr. Ellis, and Ms. LaConte disagree with the Expected Earnings analysis
16 because they believe it does not measure the market cost of equity capital. In addition, Mr.
17 Gorman contends that "the earned return on book equity is simply not an accurate or
18 legitimate basis upon which to determine a fair and reasonable return on equity for both
19 investors and customers."⁷⁹ Mr. Ellis further asserts that it has been rejected by the FERC
20 and therefore is not appropriate.

21 **Q. WHAT IS YOUR RESPONSE TO THESE CONCERNS RELATED TO THE**
22 **EXPECTED EARNINGS APPROACH?**

23 A. The Expected Earnings approach provides an expected return for like-risk companies,
24 which is a core strength of the model and consistent with the basic tenets of *Hope*, which

⁷⁸ Direct Testimony of Michael P. Gorman, at 77-78; Direct Testimony of Billie S. LaConte, at 11-12; and Direct Testimony of Mark E. Ellis, at 3, 29-32.

⁷⁹ Direct Testimony of Michael P. Gorman, at 78.

1 requires that “the return to the equity owner should be commensurate with returns on
2 investments in other enterprises having corresponding risks.” In the context of considering
3 regulated utility investment opportunities, an investor would naturally consider both
4 current market valuations in deciding between companies of like risk and the value of the
5 expected return on book value.

6 The *Hope* and *Bluefield* standards establish that a utility should be granted the opportunity
7 to earn a return that is commensurate with the return on other investments of similar risk.
8 However meritorious the theoretical criticism of the Expected Earnings methodology in
9 the context of comparing non-utility investments, the Intervenor Witnesses fail to
10 acknowledge the regulated utility’s authorized book return does, in fact, materially affect
11 the earnings and earnings growth of a regulated utility. The Expected Earnings approach
12 provides valuable insight into the opportunity cost of investing in Georgia Power’s electric
13 utility operations precisely because of the regulated context of electric utility investment
14 opportunities.

15 If investors decide to devote capital to the Company (which would offer a return of only
16 5.54 percent on book value if Mr. Ellis’ recommendation was adopted), they forgo the
17 opportunity for that same capital to earn a potentially greater return on book value through
18 investment in the proxy companies. As a result, the Expected Earnings approach is
19 informative because it provides a measure of the return on book value that is available to
20 investors through other investments with comparable risk to Georgia Power.

21 As Dr. Morin explains, the Expected Earnings approach (also referred to as the Comparable
22 Earnings approach below and by Ms. Reno) is highly meaningful in a regulatory setting
23 similar to the one being used to set the cost of equity for Georgia Power:

24 The Comparable Earnings approach is far more meaningful in the
25 regulatory arena than in the sphere of competitive firms. Unlike industrial
26 companies the earnings requirement of utilities is determined by applying a
27 percentage rate of return to the book value of a utility’s investment, and not
28 on the market value of that investment. Therefore, it stands to reason that a
29 different percentage rate of return than the market cost of capital be applied
30 when the investment base is stated in book value terms rather than market

1 value terms. In a competitive market, investment decisions are taken on the
2 basis of market prices, market values, and market cost of capital. **If**
3 **regulation's role was to duplicate the competitive result perfectly, then**
4 **the market cost of capital would be applied to the current market value**
5 **of rate base assets employed by utilities to provide service. But because**
6 **the investment base for ratemaking purposes is expressed in book value**
7 **terms, a rate of return on book value, as is the case with Comparable**
8 **Earnings, is highly meaningful.**⁸⁰

9 Further, in developing his sustainable growth rates for the DCF model, Mr. Gorman
10 assumes the reasonableness of the projected returns on book equity from Value Line for
11 the proxy group companies, which are the same returns that he dismisses as unreliable in
12 the Expected Earnings analysis.

13 Lastly, although the FERC has not included the Expected Earnings analysis in its most
14 recent orders setting its ROE methodology (i.e., Opinion Nos. 569-A and 569-B) for
15 electric transmission companies, FERC has left the door open for presentation of an
16 Expected Earnings analysis on a case-by-case basis.⁸¹ In my view, the Expected Earnings
17 analysis provides a more stable picture of the returns that investors are expecting for
18 companies in the Electric Utility sector based on Value Line data. This stability is due to
19 Value Line's analysis and projections which change when updated, in contrast to the
20 CAPM and DCF results which shift with more volatile market data. Moreover, as explained
21 in this section, the use of accounting returns is appropriate because the authorized ROE is
22 being applied to an accounting rate base in order to determine the net income a company
23 is authorized to recover in rates. For all of these reasons, I continue to support the use of
24 an Expected Earnings analysis as one model to estimate the cost of equity for Georgia
25 Power in this proceeding.

⁸⁰ New Regulatory Finance, Roger A. Morin Ph.D., Public Utility Reports, 2006, at 394-395. (emphasis added)

⁸¹ Federal Energy Regulatory Commission, Opinion No. 569-A, Order on Rehearing, issued May 21, 2020, at para. 132.

1 **V. CAPITAL STRUCTURE AND COST OF DEBT**

2 **Q. PLEASE SUMMARIZE THE INTERVENOR WITNESSES' CAPITAL**
3 **STRUCTURE RECOMMENDATIONS.**

4 A. Ms. Reno accepts the Company's proposed capital structure.⁸² Mr. Gorman accepts
5 Georgia Power's requested capital structure for 2023 until Vogtle units 3 and 4 are in
6 service. He recommends, however, that the Commission authorize an equity ratio of 51
7 percent for 2024 and 2025.⁸³ Ms. LaConte recommends the Commission authorize a capital
8 structure that consists of no more than 53 percent common equity.⁸⁴ Lastly, Mr. Ellis
9 recommends a capital structure of 61.70 percent with his 5.54 percent ROE
10 recommendation.⁸⁵

11 As to the cost of long-term debt, only Ms. Reno rejects the Company's proposed cost of
12 debt. She recommends that Georgia Power's proposed 2023 cost of debt of 3.53 percent be
13 applied for the entire term of the Alternative Rate Plan (ARP) and that the cost of debt
14 should not increase in 2024 and 2025.⁸⁶

15 **Q. ON WHAT BASIS DOES MR. GORMAN DEVELOP HIS RECOMMENDED 51**
16 **PERCENT EQUITY RATIO FOR 2024 AND 2025?**

17 A. Mr. Gorman's recommendation is based on his review of authorized equity ratios for
18 electric and gas utilities between 2010 and 2022, as well as adjusted debt ratios reported
19 by S&P for electric gas, and water utilities. He concludes that adjusting Georgia Power's
20 ratemaking capital structure to reflect a 51 percent equity ratio in 2024 and 2025 "would

82 Direct Testimony of Maureen L. Reno, at 6.

83 Direct Testimony of Michael P. Gorman, at 23-24.

84 Direct Testimony of Billie S. LaConte, at 23.

85 Direct Testimony of Mark E. Ellis, at 5.

86 Direct Testimony of Maureen L. Reno, at 17-18.

1 be consistent with the normalized industry ratemaking capital structure” and support the
2 Company’s current bond rating, or even improve it.⁸⁷

3 **Q. MR. GORMAN’S RECOMMENDATION TO REDUCE GEORGIA POWER’S**
4 **RATEMAKING CAPITAL STRUCTURE IN 2023 AND 2024 IS BASED, IN PART,**
5 **ON A REVIEW OF NATIONAL AVERAGE AUTHORIZED CAPITAL**
6 **STRUCTURE FOR ELECTRIC AND NATURAL GAS UTILITIES.⁸⁸ PLEASE**
7 **COMMENT ON THAT COMPARISON.**

8 A. Mr. Gorman’s analysis is not an apples-to-apples comparison to Georgia Power’s proposed
9 capital structure. First, his analysis includes authorized equity ratios for all rate case types
10 reported by Regulatory Research Associates, including electric T&D rate cases and limited
11 issue rate rider rate cases that are not base rate cases.⁸⁹ Electric T&D utilities have a
12 different risk profile than vertically integrated electric utilities. As Figure 18 shows, the
13 average annual authorized equity ratios for vertically integrated electric utilities are higher
14 than Mr. Gorman’s annual averages that include electric T&D utilities.

87 Direct Testimony of Michael P. Gorman, at 31-32.

88 Direct Testimony of Michael P. Gorman, at 29-30.

89 Mr. Gorman’s Confidential WP 21.

Figure 18: Average Authorized Equity Ratios (2010 – 2022)

Year	All Electric Utilities⁹⁰	Vertically Integrated Electric Utilities
2010	49.49%	50.13%
2011	49.09%	49.93%
2012	51.45%	52.37%
2013	50.12%	51.09%
2014	50.28%	51.24%
2015	50.24%	50.99%
2016	49.70%	50.04%
2017	50.02%	50.99%
2018	50.60%	51.29%
2019	51.54%	52.16%
2020	50.94%	52.02%
2021	51.01%	51.12%
2022	51.54%	51.97%

Further, although Mr. Gorman removed rate case decisions from states that include non-investor supplied capital in the ratemaking capital structure,⁹¹ his analysis includes decisions that, unlike Georgia Power, also use short-term debt in the ratemaking capital structure, biasing the authorized equity ratio downward.

Nonetheless, the range of authorized equity ratios for vertically integrated electric utilities reported by RRA since 2010 has been from 40.25 percent to 59.09 percent.⁹² Georgia Power's proposed equity ratio of 56.00 percent is well within this range and is therefore not unreasonable. Notably, Mr. Gorman's Table 7 shows an upward trend in the average

⁹⁰ Mr. Gorman's Table 7, updated for rate cases decided through November 3, 2022.

⁹¹ Specifically, Arkansas, Florida, Indiana, and Michigan.

⁹² Source: S&P Capital IQ Pro, Regulatory Research Associates. I have excluded decisions in Arkansas, Florida, Indiana, and Michigan, which include zero cost capital items that are not part of investor-provided capital.

1 authorized equity ratio between 2010 and 2022. Particularly important is the increase since
2 2016, in part to somewhat mitigate the effects of the Tax Cuts and Jobs Act on utilities'
3 cash flows and their credit profiles.

4 **VI. BUSINESS RISK AND FLOTATION COSTS**

5 **Q. DO YOU AGREE WITH MR. GORMAN'S CONTENTION THAT CREDIT**
6 **RATINGS TAKE INTO ACCOUNT ALL BUSINESS AND FINANCIAL RISKS**
7 **THAT ARE RELEVANT TO INVESTORS?⁹³**

8 A. No. Credit ratings, while important, are not the only consideration in assessing business or
9 financial risk, and the risks for equity investors are not the same as the risks for
10 bondholders. Credit ratings are assessments of the likelihood a company could default on
11 its *debt*, whereas, the purpose of setting an ROE is to determine the riskiness and cost of
12 the Company's *equity*. Equity investors are more concerned with earnings and rate base
13 growth, regulatory support for recovery of prudently incurred costs, the strength of the
14 local economy and housing markets, capital spending, changes in interest rates, changes in
15 long-term weather patterns, and more recently exposure and opportunities related to
16 decarbonization of the industry. Bondholders are primarily concerned with stability and
17 predictability of cash flows and timeliness of cost recovery as those affect a utility's ability
18 to meet its fixed obligations.

19 S&P states that it puts a negative ratings modifier on Georgia Power and ranks the
20 Company at the lower end of S&P's range for the excellent business risk category based
21 upon Georgia Power's exposure to energy transition risk and the risks associated with the
22 completion of Vogtle.⁹⁴ Further, while I have considered Georgia Power's relative
23 regulatory risk, it is important to recognize that I did not make an adjustment to my ROE
24 recommendation for business risk. Instead, I relied on the mean results of the four financial
25 models I used to estimate the cost of equity for Georgia Power.

93 Direct Testimony of Michael P. Gorman, at 79-80.

94 S&P Global Ratings, *Georgia Power Company*, November 18, 2021 at 6.

1 **Q. SEVERAL INTERVENOR WITNESSES ARGUE THAT THE COMPANY'S**
2 **ALTERNATIVE RATE PLAN AND RATE STRUCTURES MITIGATE GEORGIA**
3 **POWER'S RISK.⁹⁵ WHAT IS YOUR RESPONSE?**

4 A. It is important to remember that the cost of equity is a comparative analysis. As such, the
5 relevant point of comparison is the Company's risk relative to its peers. As explained in
6 my direct testimony and shown in Exhibit JMC-9, a substantial majority of the proxy group
7 companies employ a variety of rate structures and mechanisms to mitigate regulatory lag.
8 As demonstrated in my direct testimony, the regulatory structures available to Georgia
9 Power are no different from the perspective of the investment community than those in
10 place at the proxy companies.⁹⁶ As a result, Georgia Power is no less risky than the proxy
11 companies on account of its regulatory mechanisms. Therefore, contrary to these
12 Intervenor Witnesses, my testimony and recommendation accounts for Georgia Power's
13 regulatory mechanisms.

14 **Q. THE INTERVENOR WITNESSES DISAGREE WITH THE INCLUSION OF**
15 **FLOTATION COSTS. WHY IS IT APPROPRIATE AND NECESSARY TO**
16 **CONSIDER FLOTATION COSTS IN THE AUTHORIZED ROE?**

17 A. Flotation costs are the direct out-of-pocket costs associated with the sale of new issues of
18 common stock. In the same way that costs associated with debt issuances are recovered
19 through the cost of debt, equity issuance costs should also be recovered. Flotation costs are
20 not expenses, so they do not appear on the income statement. Instead, they are reflected on
21 the balance sheet under "Paid in Capital." Further, flotation costs are accumulated over
22 time and remain on the balance sheet even if no new equity issuances are planned. For
23 these reasons, I continue to include an adjustment for flotation costs in my ROE
24 recommendation.

95 *See, e.g.,* Billie S. LaConte, at 15-17; Direct Testimony of Maureen L. Reno, AT 24-25.

96 Direct Testimony of James M. Coyne, at 42-43.

1 **VII. CONCLUSIONS**

2 **Q. WHAT ARE YOUR CONCLUSIONS REGARDING A FAIR ROE FOR GEORGIA**
3 **POWER?**

4 A. The only reliable method for determining the cost of capital is through the application of
5 rigorous analysis using financial models and market data from reliable sources.
6 Additionally, the Commission's cost of capital determination should consider the general
7 economic and capital market environment and the influence capital market conditions exert
8 over the results of the ROE estimation models. Interest rates on government and utility
9 bonds have increased substantially in 2022 and projections suggest a continued upward
10 pressure in the coming years. This increase in the capital costs, and other risk factors
11 indicate that the uncertainty and volatility in financial markets have caused equity investors
12 to require a higher rate of return, including for electric utilities.

13 My recommended ROE of 11.0 percent and capital structure with a common equity ratio
14 of 56.0 percent is fair and reasonable for Georgia Power. This capital structure is consistent
15 with the Company's actual equity ratio, and combined with the authorized ROE will
16 support continued financial strength and access to debt and equity capital to meet the
17 Company's operating requirements.

18 **Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

19 A. Yes, it does.

**REBUTTAL TESTIMONY OF
STEVEN M. FETTER
ON BEHALF OF GEORGIA POWER COMPANY
DOCKET NO. 44280**

I. INTRODUCTION

1 **Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.**

2 A. My name is Steven M. Fetter. My business address is 1240 West Sims Way, Port
3 Townsend, Washington 98104.

4 **Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS PROCEEDING?**

5 A. Yes. I submitted direct testimony to the Georgia Public Service Commission (the
6 “Commission”) on behalf of Georgia Power Company (“Georgia Power” or the
7 “Company”) on June 24, 2022.

8 **II. PURPOSE OF REBUTTAL TESTIMONY**

9 **Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

10 A. The purpose of my rebuttal testimony is to respond to the following points testified to by
11 Kevin O’Donnell and Michael Gorman in their direct testimonies on behalf of the Georgia
12 Public Service Commission Public Interest Advocacy Staff (“PIA Staff”):

- 13 • I draw a different conclusion than Mr. O’Donnell when he states, “As can be seen
14 in the above chart [Chart 1], most utilities are in the A-, BBB+, and BBB range.”
15 (page 5);
- 16 • I disagree with Mr. O’Donnell’s assessment that, “As can be seen in Table 3
17 Georgia Power’s credit rating is similar to other southeast electric utilities.” (pages
18 5-6);

- 1 • Mr. O'Donnell is not accurate when he states that the position I took in the 2019
2 rate case about potential downgrades was shown to be inaccurate by an S&P
3 downgrade of Georgia Power on October 27, 2021, and a Moody's downgrade "on
4 August 8, 2019, just prior to the final order being issued in the last Company rate
5 case in December, 2019." (pages 19-24);
- 6 • Mr. O'Donnell's reference to the Moody's downgrade noted above is inaccurate: it
7 is off by twelve months. Moody's downgraded Georgia Power on August 8, 2018,
8 not August 8, 2019, and thus the negative rating action occurred 16 months prior to
9 the Commission's Final Order in the 2019 rate case. (page 20);
- 10 • I disagree with Mr. O'Donnell's rejection of my views related to Georgia Power's
11 credit ratings because this rejection is based solely on his quantification of interest
12 costs compared to rate costs to consumers; by adopting this approach, Mr.
13 O'Donnell ignores the approximate 50% weighting of qualitative factors that is part
14 and parcel of the analysis and assignment of credit ratings. (pages 24-27);
- 15 • I disagree with Mr. Gorman's financial recommendations of authorized ROE of
16 9.45% and equity layer moving down to 51%. (page 2); and
- 17 • I disagree with Mr. Gorman when he states, "Mr. Fetter provided no substance or
18 evidence that supports his conclusion that GPC's credit rating and financial
19 integrity are only achieved if the Company's return on equity and proposed
20 ratemaking capital structure are adopted." (page 27)

21 **III. DISCUSSION**

22 **Q. WHAT IS YOUR OVERALL CONCLUSION IN THIS REBUTTAL TESTIMONY?**

23 A. Georgia Power's credit ratings now straddle above and below the bottom of my recommended
24 credit rating range of ratings no lower than BBB+. For this reason, I encourage the Commission
25 to set Georgia Power's equity level and authorized return on equity consistent with Mr.
26 Coyne's recommendation of an 11% ROE and the Company

1 (Abramovitz/Adams/Houston/Robinson) Panel's recommendation of 56% equity ratio. In
2 my opinion, the Company's recommendations are designed to maintain the Company's
3 financial integrity with the potential of improvement over time.

4 Mr. O'Donnell supports PIA Staff witness Gorman's recommended 9.45% ROE with an
5 equity layer that sinks down from 56% to 51%. I agree with Company witnesses
6 Abramovitz and Adams that Mr. O'Donnell's recommendations would result in significant
7 movement down from Georgia Power's current financial position.¹ Mr. O'Donnell's
8 recommendations, if adopted, would also result in a negative impact to the qualitative side
9 of credit rating analysis. In short, Mr. O'Donnell's recommendation would represent such a
10 stark undermining of the Company's financial integrity that it would likely be interpreted
11 by the rating agencies as an abrupt departure from the Commission's long record of
12 constructive regulation characterized by consistency and gradualism in balancing the
13 interests of customers and investors and would be very detrimental to the Company's
14 overall credit rating profile.

15 **Q. MR. O'DONNELL PROVIDES TWO TABLES IN HIS TESTIMONY TO**
16 **SUPPORT HIS VIEW THAT ALL IS WELL AT GEORGIA POWER. YOU**
17 **INDICATE THAT YOU DISAGREE WITH HIS ASSESSMENT. PLEASE**
18 **EXPLAIN.**

19 A. In both Table 3 ("Georgia Power Comparison to Southeast Electric Utilities") and Chart 1
20 ("Utility Credit Ratings"), Mr. O'Donnell attempts to show a stable ratings environment
21 for Georgia Power by submitting an incomplete picture. Based solely on his Table 3, Mr.
22 O'Donnell states: "Georgia Power's credit rating is similar to other southeast electric
23 utilities." (pages 5-6). This is not accurate. Mr. O'Donnell's Table 3 ignores the Company's

¹ Witnesses Abramovitz and Adams also discuss how Mr. Gorman has not appropriately considered the concept of debt imputation that the credit rating agencies utilize to factor into their calculation of credit metrics debt-like instruments and circumstances that increase a utility's obligations and financial risk. That process has been a focus of the rating agencies dating back to at least the early 1990s.

lowest rating, BBB from Fitch. Below I have provided a version of his list, modified to include Fitch ratings, to show the disparity I have described:

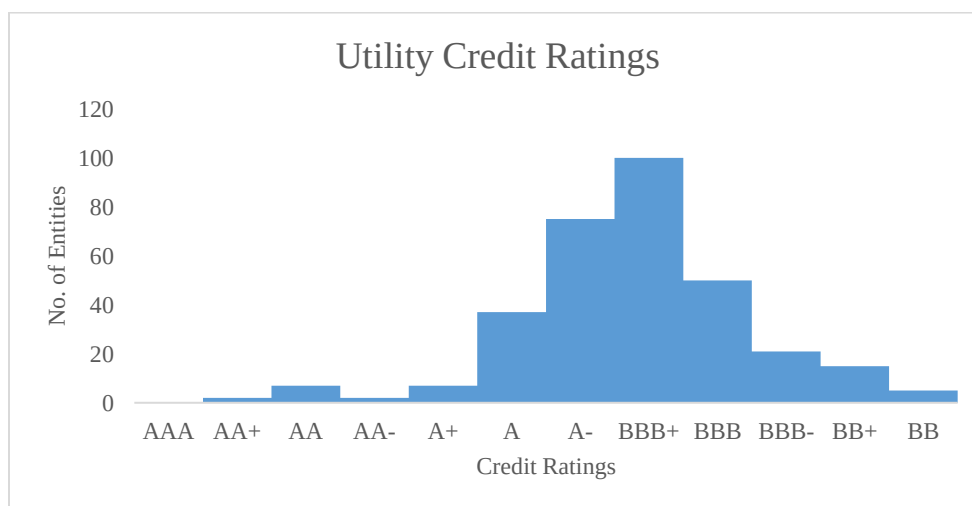
Utility	Moody's	S&P	Fitch
Florida Power & Light	A1	A	A
Alabama Power	A1	A-	A
Duke Energy Carolinas	A2	BBB+	NR
Mississippi Power	Baa1	BBB+	BBB+
Georgia Power	Baa1	BBB+	BBB

As the above chart demonstrates, in contrast to Mr. O'Donnell's assertion that Georgia Power has similar credit ratings to "other southeast electric utilities," the ratings from the three major rating agencies place the Company at the *bottom* of the list of southeast electric utilities, with a cumulative eight rating notches below Florida Power & Light and seven notches below Alabama Power.

Q. IN ADDITION, DO YOU BELIEVE THAT MR. O'DONNELL'S CHART 1 FURTHER SUPPORTS YOUR CONCERNS ABOUT GEORGIA POWER'S CREDIT RATINGS?

A. Yes. Mr. O'Donnell's Chart 1 is provided below:

Chart 1: Utility Credit Ratings



Source: Data estimated from S&P Ratings Direct Chart sent to Nova Energy Consultants on Sept. 28, 2022

Here is a breakdown of the number of utilities at each rating level:

Rating Level	Number of Utilities
AA	7
A+	7
A	37
A-	75
BBB+	100
BBB	50
BBB-	21

Investment Grade Dividing Line

BB+: 15

BB: 5

In Discussing his Table 1, Mr. O'Donnell states: "As can be seen..., most utilities are in the A-, BBB+, and BBB range." (page 5). In view of my longstanding position that regulated utilities should target having credit ratings no lower than BBB+, I think a more appropriate analysis of this chart shows that the majority of regulated utilities hold ratings of BBB+ or above – 226 – as compared to those rated below BBB+ – 91. In fact, those below BBB+ include 41 at levels no utility management, investor, or regulator would find to be acceptable: 20 below investment grade, plus 21 at the very precarious lowest investment grade rating level of BBB-. For these marginally rated utilities, one operational or financial setback, one major storm, or one cyber security attack could drive the utility below investment grade, requiring a substantial number of its investors to modify their equity/debt holdings. With Georgia Power straddling that BBB+ / BBB dividing line, now is not the time to adopt a position – as advocated by Mr. O'Donnell – that would all but guarantee that Georgia Power would for the short- and medium-term remain among the precarious marginal utilities that have little to no financial margin to mitigate the impacts of unforeseen adverse events.

Q. IN DESCRIBING YOUR TESTIMONY FROM THE COMPANY'S 2019 RATE CASE, DID MR. O'DONNELL MISCHARACTERIZE ANY PART OF YOUR TESTIMONY?

1 A. Yes. In reference to my testimony during the 2019 Georgia Power rate case, Mr. O'Donnell
2 incorrectly states: "The high ROE and equity ratio in the last rate case did not, contrary to
3 Mr. Fetter's statements in the 2019 case, prevent a credit downgrade." (page 24). First and
4 importantly, Mr. O'Donnell is factually incorrect. In his testimony Mr. O'Donnell stated
5 that the Moody's downgrade occurred "on August 8, 2019, *just prior to the final order being*
6 *issued in the last Company rate case in December, 2019.*" This statement is not accurate. The
7 Moody's downgrade was announced on August 8, **2018**, which was 16 months *before* the
8 Commission's December 2019 decision in the Georgia Power rate case, and, indeed, more
9 than a year before the initial hearing and before PIA Staff filed any testimony in the 2019
10 rate case. At the same time, prior to the 2019 rate case, S&P (on March 25, 2017) and Fitch
11 (on September 28, 2018) had already placed Negative outlooks on their Georgia Power
12 ratings, signaling the potential direction of a credit rating change within the foreseeable
13 future. The timing of the Moody's action and those Negative outlooks are relevant. They
14 indicate that the financial strength of the Company had already been weakening well before
15 the 2019 rate case, and they help explain why, after a relatively supportive regulatory
16 decision at the end of 2019, downgrades at S&P and Fitch might occur.

17 In addition to this inaccuracy, Mr. O'Donnell completely mischaracterizes my 2019 rate
18 case testimony to the Commission. Below is a full quote from my 2019 testimony:

19 In order for Georgia Power to be able to maintain its current ratings range across
20 all three agencies, I encourage the Commission to set the ROE and capital
21 structure at levels consistent with Dr. Vander Weide's recommendations. Such a
22 Commission determination would show a continuation of the strong regulatory
23 support that Georgia Power has long experienced, which should avoid further
24 weakening in the Company's credit profile. On the other hand, a less than
25 constructive decision by the Commission in this case could lead to further
26 negative credit rating actions, potentially moving the Company below the
27 'BBB+' / 'Baa1' rating level that I have long testified represents the lowest
28 appropriate credit rating level for a U.S. regulated utility. (pages 22-23).

29 What is important to note is that in my prior testimony, I was referring to Dr. James Vander
30 Weide's recommendation that the Commission set an authorized ROE of 10.9% with an
31 equity level of 56%. The Company ultimately agreed to a settlement resolving all issues
32 except the Company's set point ROE and equity ratio, which were deferred to the

1 Commission, which authorized an ROE of 10.5% and an equity ratio of 56%. Even though
2 my recommendation was superseded by the settlement, I was still hopeful that the lower,
3 albeit still supportive, Commission-ordered financial parameters would overcome the
4 pending Negative outlooks at S&P and Fitch. Unfortunately, they could not, with S&P
5 bringing Georgia Power's rating to BBB+ and Fitch going even lower at BBB. (Moody's,
6 of course, had acted long before both my testimony and the Commission decision.) I still
7 firmly believe that the financial enhancement that would have been provided by Dr. Vander
8 Weide's recommended 10.9% ROE level could have forestalled Fitch's move to BBB,
9 below my recommended range of no lower than BBB+.

10 **Q. YOU ALSO CHALLENGE MR. O'DONNELL'S APPROACH OF FOCUSING ON**
11 **THE FINANCIAL SIDE OF CREDIT RATINGS WITHOUT CONSIDERING THE**
12 **QUALITATIVE FACTORS INVOLVED IN THE RATINGS PROCESS. PLEASE**
13 **EXPLAIN.**

14 A. While credit rating agencies certainly give great weight to financial metrics when
15 formulating their credit ratings, Mr. O'Donnell has not given appropriate consideration to
16 qualitative rating factors, most especially "Regulation." Based on my leadership role at a
17 major rating agency, I know that the qualitative assessment is given virtually equal weight
18 as the quantitative factors in coming to a rating determination. As I discussed in my direct
19 testimony, "Regulation" is the most important qualitative factor. Mr. O'Donnell supports
20 Mr. Gorman's proposed significant downward movement in Georgia Power's financial
21 measures, while both of them ignore the qualitative impacts. This is a mistake, and, in my
22 view, has resulted in incomplete analyses by those two witnesses. If adopted by this
23 Commission, Mr. Gorman's recommendations would represent a clear break from the
24 Commission's past constructive decision-making. The likely result would be negative
25 actions by the rating agencies as they recognize both the less supportive financial measures
26 as well as qualitative judgments pointing toward a potential reordering of the state's
27 regulatory philosophy.

1 **Q. WOULD SUCH A MAJOR RESETTING OF THE GEORGIA REGULATORY**
2 **CLIMATE HAVE A SIGNIFICANT EFFECT ON GEORGIA POWER’S DAY-TO-**
3 **DAY OPERATIONS?**

4 A. Yes, and the key reason is “Access” to the capital markets. During the past 15 years, we
5 have seen even “A”-rated utilities encounter issues regarding access to capital markets during
6 times of stress such as the 2008-2009 recession and the economic concerns that
7 accompanied the early onset of the COVID contagion. At cross-examination of my direct
8 testimony, I shared the story of Entergy New Orleans (“ENO”) pre-and-post Hurricane
9 Katrina. Prior to Katrina, ENO was a financially improving regulated utility that had
10 solidified its Moody’s credit rating at the Baa3 investment-grade level with expected near-
11 term positive movement. Katrina hit New Orleans during the last week of August 2005.
12 Within three weeks, ENO’s rating had fallen to Ca, far below investment-grade level. With
13 its access to the capital markets completely shut off, parent Entergy Corp. moved ENO into
14 bankruptcy, which then opened the way for the parent to begin funding ENO’s long
15 struggle back toward financial stability. It is important to note that all of my talk about the
16 precarious nature of BBB- ratings can be seen within ENO’s saga – that utility has had its ups and
17 downs since Katrina, but as of now, 17 years later, ENO sits below investment grade in the Ba /
18 BB category at both Moody’s and S&P.

19 With access in mind, I attempted to follow Mr. O’Donnell’s complex financial analysis
20 (pages 25-27) about the cost of a downgrade compared to the potential cost to customers
21 resulting from this rate case. I found it interesting that, if I understand his methodology
22 correctly, Mr. O’Donnell is calculating Georgia Power’s potential movement down
23 through the BBB category, with each step equal in financial pain. Thus, he sets the cost of
24 a downgrade from Baa1 to Baa2 as 14 basis points of interest, resulting in additional
25 financing cost for the Company of \$96 million. He then compares this to his hypothetical
26 calculated increased customer rate cost of \$1.26 billion. He at no time states that a Baa1
27 utility (which would be within my recommended range) would be a much more attractive
28 investment target for the financial community than would be the declining number of
29 utilities holding Baa2 ratings. I have always believed that the best way to test a hypothesis that

appears compelling, but which one fears might be suspect, is to take the assumptions another step further, and even still further (eventually to absurd levels), which I will proceed to do.

I noted earlier the precarious situation a regulated utility would find itself in with a rating of Baa3 – the lowest investment-grade level and thus the bane of investors who fear that one notch down puts the rating “off a cliff.” Taking Mr. O’Donnell’s assumptions, financing at the anxiety-producing Baa3 level would cost another 14 basis points, or \$96 million more, providing this comparison: additional financing costs of \$192 million compared to consumer costs of \$1.26 billion. Now, let’s take this to the absurd level – Georgia Power and its regulators, with the encouragement of some intervenors, decide to allow the Company’s credit rating to free fall to below investment-grade level at BB. The chart below demonstrates the differential in the cost of 10-year debt going down into the junk bond level of the BB category over the past decade.

		10-Year A Utility Index	10-Year BBB Utility Index	10-Year BB Utility Index
12/30/2011	YE '11	3.14%	4.05%	6.25%
12/31/2012	YE '12	2.66%	3.38%	5.26%
12/31/2013	YE '13	3.83%	4.48%	6.05%
12/31/2014	YE '14	3.12%	3.46%	5.22%
12/31/2015	YE '15	3.56%	4.02%	6.79%
12/30/2016	YE '16	3.39%	3.71%	5.71%
12/29/2017	YE '17	3.22%	3.43%	4.61%
12/31/2018	YE '18	3.98%	4.48%	6.98%
12/31/2019	YE '19	2.80%	3.12%	4.51%
12/31/2020	YE '20	1.82%	1.97%	3.10%
12/31/2021	YE '21	2.43%	2.63%	3.37%
10/28/2022	Current	5.61%	6.06%	6.77%

Source: Bloomberg

As this chart shows, the increase in interest cost between the BBB and BB categories varies depending upon capital markets conditions but approximately spans the range of 10% to 60% more. I would estimate that a significant percentage of investment institutions would no longer be permitted to invest in such below investment-grade bonds – or would have to modify their current holdings going forward. Utilizing the above data, one could multiply the negative cost of Mr. O’Donnell’s one-notch downgrade analysis by 100% and *still* show a preference for the increased

1 interest costs at close to \$400 million for the three-notch downgrade versus consumer rate costs
2 of \$1.26 billion, all the while basically eliminating most of the outside financing access then
3 available to the Company. At cross-examination on his testimony, Mr. O'Donnell even suggested
4 that if the Company's ratings were to fall too low to access traditional financing, there would
5 always be the option to run its multi-billion-dollar business using private placement financing,
6 usually reserved to fund construction of individual plants or projects.² Mr. O'Donnell's suggestion
7 stretches access to capital markets far beyond logical reasoning and does not equate to the required
8 level of access on reasonable terms.

9 The bottom line is that credit rating analysis is not solely a numbers game. Rating agencies
10 weigh quantitative and qualitative factors on a virtually equal basis, so only looking at
11 quantitative factors will not render an appropriate strategy, nor will only focusing on
12 qualitative factors, most especially regulation, provide a valid plan. The two sides must be
13 weighed equally, which I have done in every one of the cases in which I have testified,
14 using the same fairness parameters whether I was testifying for a regulated utility, a public
15 utility commission, or a consumer advocate.

16 **Q. MR. GORMAN CLAIMS THAT YOU PROVIDE “NO SUBSTANCE SUPPORTING**
17 **OR EVIDENCE THAT SUPPORTS [YOUR] CONCLUSION THAT GPC’S CREDIT**
18 **RATING AND FINANCIAL INTEGRITY ARE ONLY ACHIEVED IF THE**
19 **COMPANY’S RETURN ON EQUITY AND PROPOSED RATEMAKING CAPITAL**
20 **STRUCTURE ARE ADOPTED.” PLEASE COMMENT ON THIS STATEMENT.**

21 **A.** Mr. Gorman is wrong. And if I may, I would like to begin my answer to Mr. Gorman's
22 claim by offering a serious and critical question: “Where would Georgia Power – and its
23 customers and, indeed, the state of Georgia – be now if, instead of approving the settlement
24 and setting authorized ROE at 10.5% with a 56% equity layer, the regulators in 2019 had
25 adopted Mr. Gorman's recommendation of authorized ROE of 9.25% with equity at 51%?”
26 Purely on a financial analytical basis, I expect the Company would have probably been just

² PSC Docket No.44280 GPC 2022 Rate Case (11/10/2022); Day 3 of Cross Examination, time stamp 3:49:30.

1 slightly “north” of the investment-grade / non-investment grade dividing line at BBB- /
2 Baa3. But when the negative qualitative effects were layered in, junk bond status would
3 likely not have been out of the question. With Vogtle so close to completion now (assisted
4 by that supportive 2019 rate case settlement and Commission approval), I cannot imagine
5 that the small increment of rate relief flowing from Mr. Gorman’s position back then would
6 have balanced out the negative effects of Georgia Power’s impaired capital markets access,
7 higher interest costs for multiple years to come, and a degree of doubt whether Vogtle
8 would have been able to progress to the point of knocking on the door of startup. Those are
9 the facts upon which I stand now, as the Commission is faced with almost the very same
10 question – whether to accept Mr. O’Donnell’s financial proposals for short-term rate gain,
11 or solidify the Company’s current ratings, with positive movement likely with the
12 successful startup of Vogtle.

13 **IV. CONCLUSION**

14 **Q. MR. FETTER, DO YOU HAVE ANY CONCLUDING THOUGHTS?**

15 A. Yes, I do. I have testified before the Georgia Public Service Commission for almost two
16 decades. As a former Commission Chairman and head of a major utility ratings practice, I
17 have respected this Commission’s commitment to adjudicating cases with a long-term
18 vision, one that incorporates both quantitative and qualitative factors. Accordingly, for the
19 reasons stated above, my recommendation remains the same as in my direct testimony. The
20 Commission should maintain its longstanding commitment to constructive regulation,
21 which has provided the Company a framework within which to attract capital and provide
22 quality service to customers, while also taking the steps necessary to move forward when
23 unexpected impediments have arisen.

24 **Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?**

25 A. Yes.

1 VICE CHAIRMAN ECHOLS: And, Madam Chair, before
2 they get started, remember you're under oath, so let
3 me just ask you while I have got you under oath. Did
4 either of you see Smokey and the Bandit? You're from
5 Massachusetts? Okay. That's it. Thanks.

6 MR. COYNE: Subject to check, I'd say I don't
7 remember.

8 MR. FETTER: I know that Burt Reynolds was in
9 it.

10 VICE CHAIRMAN ECHOLS: Yeah, good. Okay.

11 MR. COYNE: I saw other Burt Reynolds. I just
12 don't remember if I saw that one.

13 VICE CHAIRMAN ECHOLS: Quintessential Georgia
14 film, so...

15 MADAM CHAIR PRIDEMORE: Probably the most
16 quintessential Georgia film.

17 VICE CHAIRMAN ECHOLS: Filmed in my home
18 county. There were black Trans Ams all over
19 Jonesboro.

20 MR. COYNE: It sounds like an undertaking.

21 VICE CHAIRMAN ECHOLS: They were wrecking them
22 everywhere.

23 COMMISSIONER SHAW: I prefer Gator. That was
24 filmed in my hometown. At least the best part.

25 VICE CHAIRMAN ECHOLS: Sorry.

1 MADAM CHAIR PRIDEMORE: This moment of
2 post-lunch fun brought to you by the late Burt
3 Reynolds.

4 Go ahead.

5 MR. MARZO: Thank you Madam Chair. With your
6 permission, I would ask that Mr. Coyne first
7 summarize his testimony and then Mr. Fetter
8 separately summarize his testimony.

9 MADAM CHAIR PRIDEMORE: Please go ahead.

10 BY MR. MARZO:

11 Q Mr. Coyne.

12 A (Witness Coyne) Thank you.

13 Good afternoon, Madam Chair, Commissioners. In
14 my direct testimony, I concluded that the appropriate rate
15 of return or return on equity for Georgia Power is
16 11 percent. My recommendation is based on the average of
17 four financial models with inputs from capital markets and
18 reputable third-party sources relied upon by investors. I
19 believe this represents an accurate estimate of the required
20 equity return for a company with Georgia Power's risk
21 profile.

22 When combined with the company's requested
23 capital structure of 56 percent equity and 44 percent
24 long-term debt, this return will support the company's
25 credit ratings. It will provide ongoing access to capital

1 on reasonable terms. And it represents a fair return for
2 both customers and shareholders.

3 By contrast, the intervenor witnesses in this
4 proceeding recommend ROEs ranging from 5.54 percent to
5 9.83 percent, which are between --

6 MADAM CHAIR PRIDEMORE: I am sorry. Please go
7 ahead.

8 A (Witness Coyne) I'll just start -- I'll start
9 that sentence again.

10 MADAM CHAIR PRIDEMORE: Thank you.

11 A (Witness Coyne) By contrast, the intervenor
12 witnesses in this proceeding recommend ROEs ranging from
13 5.54 percent to 9.83 percent, which are between 67 and
14 nearly 500 basis points below Georgia Power's currently
15 authorized ROE.

16 At one end of the spectrum, one must question a
17 recommendation that is 300 basis points below any return
18 authorized for any electric utility in at least 40 years and
19 lower the current yields on utility debt. It is simply
20 illogical to expect that a rational investor would take on
21 the risk of a utility equity investment when they could
22 return a higher return from a safer bond that has a senior
23 claim on cash flow.

24 Moreover, an ROE within the range of the
25 intervenor witnesses' recommendations would reflect a

1 substantial departure from the Commission's constructive and
2 supportive regulatory environment.

3 Further, their recommendations to substantially
4 decrease the company's authorized return cannot be
5 reconciled with the current market environment in which
6 treasury bond yields and utility bond yields have increased
7 by approximately 160 to 230 basis points respectively since
8 the company's last rate case.

9 A reduction in the allowed return runs counter
10 to capital market trends and is especially important when
11 considering that this rate of return will be in effect for
12 the next three years. As the Commission is aware, Georgia's
13 regulatory environment has been consistently rated as one of
14 the most supportive and constructive relative to other U.S.
15 regulatory environments.

16 This is a result of its consistent and
17 predictable regulatory outcomes that provide timely recovery
18 of costs and a reasonable opportunity for regulated
19 utilities to earn a fair return.

20 This -- the supportiveness of the Commission's
21 regulatory decisions for Georgia Power has enabled it to
22 construct the Vogtle facility, which will provide customers
23 with clean energy for decades.

24 It is critical that the Commission-supported
25 regulatory environment be maintained. If the Commission

1 were to authorize a return within the range of the
2 intervenor witness recommended -- return recommendations, it
3 would signal a less consistent and predictable regulatory
4 environment, introducing a greater level of regulatory risk
5 and less credit support.

6 Because Georgia Power is undertaking the
7 challenging task to reduce carbon emissions while continuing
8 to provide safe and reliable service and sustain its
9 earnings and credit quality, it is important for the company
10 to have the financial strength required to finance the
11 necessary investments and to continue to attract both debt
12 and equity capital to manage through this transition.

13 As explained in my rebuttal testimony, my
14 11 percent ROE recommendation is more consistent with the
15 ROEs recently authorized for above-average regulatory
16 jurisdictions such as Georgia.

17 My recommendation also better reflects the
18 current trend of higher capital costs and inflation, a
19 headwind that the company will have to manage during the
20 term of its alternative rate plan.

21 As I discuss in my rebuttal testimony, bond
22 yields are currently at the highest levels in at least
23 seven years, credit spreads have widened over the course of
24 the year, and utility stock volatility remains elevated.

25 The intervenor witness recommendations to

1 substantially reduce the company's authorized ROE run
2 counter to market evidence of higher utility risk and higher
3 capital costs.

4 Some of the intervenor witnesses reference
5 lower allowed returns in other jurisdictions or national
6 averages as a basis for their recommendations. But these
7 averages must be placed in the proper context.

8 First, averages including T&D-only utilities
9 are not directly comparable to Georgia Power, a fully
10 integrated utility with full responsibility for its
11 generation fleet.

12 Second, market conditions at the time of those
13 decisions do not reflect today's capital markets or those
14 Georgia Power will face over the next three years.

15 Finally, these commissions are not ranked as
16 highly as Georgia for their constructive regulatory
17 environment.

18 One could look to similarly ranked Florida
19 where that commission recently allowed a return of
20 10.8 percent on a 59.6 percent equity ratio for FPL's
21 four-year rate plan commencing in 2022.

22 As to the company's capital structure, Georgia
23 Power's requested capital structure of 56 percent common
24 equity and 44 percent long-term debt is within the range of
25 actual capital structures maintained by the electric

1 operating subsidiaries of the proxy group companies used in
2 my analysis and those allowed by their commissions.

3 The intervenor witnesses have recommended
4 equity ratios varying from 51 percent to 61.7 percent,
5 including one recommendation for a decrease in the company's
6 equity ratio when Vogtle comes online.

7 I do not believe that any of these
8 recommendations adequately reflect Georgia Power's need for
9 continued access to capital on reasonable terms and the
10 importance of maintaining its credit quality.

11 I agree with this Commission's finding in 2019
12 that a capital structure of 56 percent equity is just and
13 reasonable and, in my view, remains so today.

14 It is also the actual equity ratio that the
15 company maintains on its balance sheet to support its credit
16 quality to the direct benefit of its customers.

17 In conclusion, it is important that the
18 Commission maintain its supportive regulatory environment
19 for Georgia Power to maintain its financial integrity needed
20 to operate a reliable electric system and meet the energy
21 needs of its customers.

22 My 11 percent ROE recommendation coupled with
23 the company's 56 percent equity ratio reasonably reflects
24 investors' return requirements in the current market and
25 fully satisfies the requirements of a fair return

1 established by the Hope and Bluefield standards.

2 Thank you.

3 MADAM CHAIR PRIDEMORE: Go ahead, Mr. Fetter.

4 A (Witness Fetter) Good afternoon, Madam Chair
5 and Commissioners. I appreciate the opportunity to respond
6 to public interest advocacy staff witnesses Kevin O'Donnell
7 and Michael Gorman, who call for an unprecedented reduction
8 in Georgia Power's authorized return on equity and equity
9 level.

10 Specifically I disagree with Mr. O'Donnell's
11 discussion of appropriate credit rating levels and where
12 Georgia Power's ratings sit as compared to its regulated
13 utility neighbors.

14 Further, I explain how Mr. O'Donnell has
15 inaccurately portrayed my recommendations in the company's
16 2019 rate case, vis-a-vis the timing of Georgia Power credit
17 rating downgrades.

18 I also dispute his exclusive focus on financial
19 rating factors and, to my eyes, erroneous quantification
20 thereof, given the fact that all three major rating agencies
21 weigh qualitative factors virtually equal to quantitative
22 measures, as I know full well dating back to my days as head
23 of the Fitch utility ratings team.

24 Finally, I opine that Mr. Gorman's 9.45 percent
25 ROE recommendation and his call for the company's equity

1 layer to decline to 51 percent would damage both the
2 company's financial integrity as well as the longstanding
3 reputation of this Commission for carrying out constructive
4 and appropriately supportive regulation.

5 As the rating agencies have made clear, Georgia
6 Power stands at an inflection point as Vogtle nears
7 completion.

8 Positive progress should stabilize the
9 company's financial position going forward while further
10 delay could place the company's current ratings into
11 jeopardy, potentially placing them below the range I have
12 long recommended for all regulated utilities.

13 Mr. Gorman's starkly negative recommendations
14 here with Mr. O'Donnell's explicit endorsement would have
15 both negative quantitative impacts as discussed in the
16 company panel's testimonies and adverse qualitative effects
17 as I have laid out in my filings.

18 If adopted, Mr. Gorman's positions would likely
19 lead to negative rating actions, to the detriment of the
20 company and its customers and investors.

21 To avoid such negative result, I encourage the
22 Commission to maintain its steady support of Georgia Power
23 as the company works through Vogtle startup and during the
24 entire alternative rate plan period of 2023 through 2025.

25 Accordingly, I continue to recommend that the

1 Commission maintain Georgia Power's financial profile no
2 lower than its current equity level of 56 percent, along
3 with Mr. Coyne's authorized ROE recommendation of
4 11 percent, which represents a small increment up from
5 current status that is clearly supported by Mr. Coyne's
6 market analysis.

7 Such action should at a minimum preserve the
8 company's current credit ratings with the potential for
9 positive ratings movement down the road, all the while
10 remaining consistent with this Commission's long record of
11 constructive decision-making.

12 Thank you.

13 MR. MARZO: Thank you, Mr. Coyne. Thank you,
14 Mr. Fetter.

15 Madam Chair, the witnesses are available for
16 questions from the Commission and for
17 cross-examination.

18 MADAM CHAIR PRIDEMORE: Commissioners?

19 (No response.)

20 MADAM CHAIR PRIDEMORE: Georgia Public Service
21 Commission?

22 MR. THOMAS: Thank you, Madam Chair.

23 CROSS-EXAMINATION

24 BY MR. THOMAS:

25 Q Preston Thomas on behalf of PIA staff.

1 Mr. Fetter, we can start with you. Am I
2 correct that this Commission granted an ROE of 10.5 percent
3 and an equity ratio of 56 percent, well above the national
4 average, in the 2019 rate case?

5 A (Witness Fetter) Well, those are the numbers
6 that they issued in the 2019 rate case.

7 Q Thank you. And all else equal, the higher ROE
8 and equity ratio resulted in higher revenue requirements for
9 ratepayers during that 2020 to 2022 period. Correct?

10 A (Witness Fetter) Higher than?

11 Q Higher than if an average ROE had been adopted.

12 A (Witness Fetter) You are saying an average for
13 all utilities regardless -- regardless of their components
14 across the country, regardless of laws in --

15 Q Right. I am just saying that there's --

16 A (Witness Fetter) I'm just trying to get an
17 understanding. You are saying an average of all -- of all
18 utilities of all stripes, even if they bore no relation to
19 Georgia Power? That's what you are asking me?

20 Q I am asking you that if compared to an average
21 ROE for integrated utilities across the country, all things
22 being equal, a higher ROE and equity ratio results in higher
23 revenue requirements for ratepayers; correct?

24 A (Witness Fetter) If the ROE is higher and the
25 equity layer is higher, then rates would be higher than if

1 those two financial components were lower.

2 Q Thank you. And the purpose of the higher ROE
3 and equity ratio was to strengthen the company's financial
4 profile so that it could issue debt at less cost; correct?
5 And maintain credit --

6 A (Witness Fetter) As I recall, the 56 percent
7 was put in place after the tax reform law at the federal
8 level. And so it was to prevent degradation of the
9 company's financial stability.

10 Q And the company's credit rating was downgraded
11 after the 2019 rate case regardless of the 10.5 ROE and the
12 cap structure; correct?

13 A (Witness Fetter) Well, contrary to
14 Mr. O'Donnell's testimony, Moody's downgraded it a year
15 before that rate case. Both S&P and Fitch had it on
16 negative outlook at the time of the rate case. And after
17 the rate case was concluded, those two entities lowered
18 their ratings. Moody's of course had lowered it a year
19 before the rate case.

20 Q So the 10.5 percent ROE and cap structure
21 didn't prevent them, the company, from experiencing a
22 downgrade; correct?

23 A (Witness Fetter) They were on negative outlook
24 at the time of the rate case, and S&P and Fitch followed
25 their competitor Moody's in downgrading the company.

1 Q Okay. And because of that, all else equal, the
2 cost of debt issued after those downgrades was more
3 expensive as a result; correct?

4 A (Witness Fetter) I am not sure what debt the
5 company issued at the time, but if they issued debt at the
6 downgraded level, it likely would have been at a higher
7 cost.

8 Q Thank you. So ratepayers in essence paid
9 higher revenue requirements due to the higher ROE and equity
10 ratio. And due to the downgrade, they also paid higher
11 interest expense on any debt that might have been issued
12 after that downgrade; correct?

13 A (Witness Fetter) Well, so the first half of
14 your sentence is they -- you are saying they paid a higher
15 revenue requirement than, like, a utility in Iowa; right?

16 Q Well, I think --

17 A (Witness Fetter) That's what you are saying to
18 me?

19 Q Yes, sir. I believe you answered the question
20 earlier that, all else equal, the higher ROE would result in
21 higher revenue requirements for the ratepayer.

22 A (Witness Fetter) Compared to utilities in
23 other states.

24 Q That's right.

25 A (Witness Fetter) And I agreed that they would

1 pay more without discussing at all the differentials between
2 all those utilities in other states.

3 Q Right. And so in addition to that higher
4 revenue requirement, they also paid more for any debt that
5 was incurred after that downgrade; correct?

6 A (Witness Fetter) Well, Moody's had downgraded
7 the company a year before the rate case, and the other two
8 utilities were a negative outlook.

9 So I think most of the negative impact would
10 have already occurred with regard to their issuance. But
11 with the other two utilities then downgrading, I would say
12 it would be a small increment in interest more, but the
13 trend was clearly negative, and that's how the financial
14 community would have viewed it, starting a year before the
15 rate case.

16 Q But those two downgrades, S&P and Fitch, surely
17 would have continued that trend; correct?

18 A (Witness Fetter) It would have continued the
19 trend, but I think, as I said, with Moody's acting a year
20 before the case and the other two being negative at the time
21 of the case, the financial community clearly saw that there
22 was a negative direction, a negative trend, and it would
23 have factored most of the increased cost to interest
24 already.

25 But I will yield in your -- your saying that

1 there would be another small increment once those two other
2 downgrades occurred.

3 Q Thank you. And would you agree that
4 construction delays and cost overruns at Vogtle 3 and 4 were
5 the primary reason the company got downgraded despite that
6 higher-than-average ROE and cap structure?

7 A (Witness Fetter) Well, as I discussed
8 during -- in my direct testimony and during cross by you
9 earlier, ratings are always an overall look at everything,
10 and so they would have factored Vogtle in. They would have
11 factored in the positive reputation of this Commission, and
12 they would have factored in the fact that Georgia Power and
13 the other regulated subsidiaries have a parent company that
14 is willing to step in and support their financial situation
15 on an ongoing basis.

16 All of those would get wrapped together in a
17 rating agency coming to a decision on assigning a rating or
18 changing a rating.

19 Q But you do agree that Vogtle 3 and 4
20 construction delays and cost overruns had a large impact on
21 that decision; correct?

22 A (Witness Fetter) Those -- it would be an
23 important factor in the rating agency analysis.

24 Q Thank you. And according to the company, both
25 Vogtle Units 3 and 4 should be in operation and in rates in

1 about a year.

2 When that happens, would you expect rating
3 agencies to view that favorably?

4 A (Witness Fetter) I believe from the most
5 recent writings from the rating agencies, they -- they
6 expect that positive progress. So they factored in a lot of
7 that, but clearly on the day they flip the switch, that
8 would be a further positive step in the eyes of the rating
9 agencies.

10 MR. THOMAS: Thank you. Madam Chair, did I --
11 at this time I would like to approach on one exhibit,
12 but I am going to go ahead and mark all of them as
13 requested. So I have Staff Exhibit STF-116, the
14 Third Quarter Earnings Call slide deck. I have
15 STF-117, the Southern Company Earnings Call
16 Transcripts. And STF-118, the RRA Regulatory Focus
17 quarterly update on decided rate cases, that I would
18 like to mark at this time.

19 MADAM CHAIR PRIDEMORE: So marked. You may
20 distribute.

21 (The documents referred to were marked for
22 identification as Exhibits Staff 116, Staff 117, and
23 Staff 118.)

24 MR. THOMAS: Thank you.

25 MADAM CHAIR PRIDEMORE: You can go ahead,

1 Mr. Thomas.

2 BY MR. THOMAS:

3 Q Okay. Mr. Fetter, if you could look at
4 STF-116, the slide deck from the third quarter of 2022
5 earnings conference call, and turn to page 21.

6 A (Witness Fetter) I am there.

7 Q Are you there? Okay.

8 Would you agree that according to the company,
9 annual operating cash flow will increase by roughly
10 \$700 million with the completion of Vogtle?

11 A (Witness Fetter) I will have to look this
12 over.

13 Q Okay. Whenever you are ready.

14 A (Witness Fetter) Okay. This is attempting to
15 illustrate certain steps that could occur, and it has
16 several assumptions down in the footnotes. But it appears
17 that it would indicate improvement in the cash flow.

18 Q In the realm of approximately \$700 million, it
19 looks like?

20 A (Witness Fetter) Based on -- based on the
21 assumptions listed below.

22 Q Okay. Thank you.

23 And could I have you turn to page 18 of the
24 earning calls transcript, please.

25 A (Witness Fetter) Is this the next -- is this

1 the same document?

2 Q It is a different document. The earning calls
3 transcript. It looks like this.

4 A (Witness Fetter) Okay. And you want me at
5 page 18?

6 Q Yes, sir, that is correct.

7 A (Witness Fetter) Okay.

8 Q And would you mind just reading aloud the
9 highlighted portion?

10 A (Witness Fetter) Okay. I am going to -- with
11 the Commission's leave, I will read the entire paragraph to
12 myself.

13 Q Okay.

14 A (Witness Fetter) Before reading the
15 highlighted portion.

16 MADAM CHAIR PRIDEMORE: Go ahead, Mr. Fetter.

17 MR. FETTER: Thank you, Madam Chair.

18 A (Witness Fetter) Okay. Now I will read the
19 highlighted portion.

20 BY MR. THOMAS:

21 Q Thank you.

22 A (Witness Fetter) "If you look in our slide
23 deck, slide 21 kind of represents the uplift from the
24 completion of Vogtle from a cash flow perspective. We are
25 really thinking about that uplift supporting three things.

1 One is an improvement in our overall financial profile, in
2 particular our credit profile."

3 Q And do you agree with Mr. Tucker in his
4 assessment that this will improve the overall financial
5 profile of the company?

6 A (Witness Fetter) Yes, on a financial basis, it
7 would improve the credit profile. As I said, rating
8 agencies have a certain expectation. And so qualitatively,
9 I think they are kind of expecting this positive movement
10 during the next year. So they have factored some of that
11 into their thinking already. And then once that step
12 occurs, it would solidify their positive view.

13 Q And subject to check, would you accept that the
14 \$700 million increase represents an increase of
15 approximately 25 percent over the \$2.7 billion of operating
16 cash flow in 2021?

17 A (Witness Fetter) I mean, I have no way of
18 knowing that. So if you want to state that subject to
19 check, the Commission can decide whether your statement is
20 accurate.

21 Q Okay. Well, let me ask you a broader question
22 then.

23 Stronger operating cash flow would help support
24 the company's overall profile and their credit rating;
25 correct?

1 A (Witness Fetter) Stronger cash flow would be
2 supportive of the rating, yes.

3 Q Okay. And given this large increase in the
4 operating cash flow, the ROE of 11 percent and the equity
5 ratio of 50 percent -- 56 percent requested by the company
6 may not be necessary to support the financial profile or
7 prevent a credit downgrade.

8 Do you agree with that?

9 A (Witness Fetter) Well, I think -- I think a
10 credit downgrade probably would not occur. Right now, as I
11 discussed at the last hearing, Fitch has the company at BBB,
12 which I think is outside in a negative direction from my
13 view of where rating should be, which would be BBB+ and
14 above. It is a consistent position I have had during my
15 20 years as an expert witness.

16 And so I think the 700 million plus or minus
17 would do a lot towards moving the Fitch rating up into the
18 BBB+ level that I think would be the most appropriate level
19 at this point for the company.

20 Q Thank you. And would you agree that this
21 Commission must balance the interests of ratepayers and
22 investors?

23 A (Witness Fetter) That's what I always did when
24 I was chairman of the Michigan Commission.

25 Q Thank you. And you are aware, of course, that

1 for ratepayers there is a trade-off between higher revenue
2 requirements for -- from the higher ROE and equity ratio
3 compared to the increase in interest expense from new debt
4 issued by the company; correct?

5 A (Witness Fetter) Yes. In fact, I analyzed
6 Mr. O'Donnell's analysis, and I found it faulty for the
7 reasons I gave in my rebuttal, which is that the comparison
8 as portrayed by Mr. O'Donnell basically would be supportive
9 of if Georgia Power was forced downward into
10 below-investment-grade category, the comparison between
11 increased interest costs and the rate impact to this case
12 would still point under his analysis to an appropriate step
13 by this Commission.

14 And I don't think there is a commissioner in
15 the country who would view that driving their key electric
16 utility to junk bond status would be the appropriate step,
17 even if the increased interest did not overwhelm the rate
18 increase being considered in a rate case.

19 Q So you have raised the specter of bankruptcy
20 and junk bond status, but the ROEs recommended in this case
21 by staff, GAM, and DoD, they are all above the national
22 average.

23 Do you think that an investor-owned utility in
24 this country would be pushed to junk bond status for
25 adopting an ROE above the national average?

1 A (Witness Fetter) I think you have misstated
2 what I just said. I said Mr. O'Donnell's analysis was found
3 faulty because I took it to an absurd level, which would be
4 junk bond or close to bankruptcy status. And that's why his
5 argument should be tossed out.

6 Now I can move on to your next question, which
7 is -- which you are going to state again so I know what you
8 are asking me.

9 Q Okay. So I heard the word "junk bond status."
10 But the ROEs recommended in this case by staff, GAM, DoD,
11 they are all at or above the national average.

12 So do you think that the -- adopting a
13 recommended ROE that's at or above the national average
14 would push this utility towards junk bond status?

15 A (Witness Fetter) I believe its credit ratings
16 would weaken, and so it -- you know, I am not saying it is
17 going to become junk bond, but right now it has one rating
18 two notches above junk bond status.

19 And so on a quantitative basis, it would weaken
20 the credit profile. And on a qualitative basis, I think the
21 financial community would be surprised. Especially, I think
22 one of the recommended ROEs was five-point something. And
23 that certainly would -- the -- Wall Street would find that
24 stunning.

25 And with regard to the recommendations in the

1 nine-point range, as I note in my rebuttal, had this
2 Commission adopted Mr. Gorman's 9.21 ROE in 2019, I think
3 the weakening in Georgia Power's credit ratings would have
4 been exacerbated and probably would have been close to the
5 below-investment-grade dividing line. I think it is a
6 strong chance ratings would have been at the BBB- level.

7 And so I think adopting 9.21 back then would
8 have been a mistake. And I think adopting 9.45 in this case
9 would be a mistake.

10 VICE CHAIRMAN ECHOLS: Let me ask you a quick
11 question, sir.

12 What do you think will have the greatest
13 impact: Our decision in this rate case or the
14 completion of Vogtle 3, in terms of moving the
15 company up above BBB?

16 MR. FETTER: Well, when you say "above BBB," I
17 am looking for solidifying the rating at BBB+ for all
18 three agencies. Right now Fitch is below that.

19 This decision will be very important. I think
20 that the movement towards startup of Vogtle, the
21 rating agencies have factored in that that's going to
22 happen.

23 So if that does not happen, if there are
24 greater delays, if it is put off for another year or
25 two, that will be incredibly negative in the eyes of

1 the rating agencies.

2 So the agencies are looking closely at what you
3 are going to do in this case, and they are expecting
4 Vogtle to continue the positive path that has been
5 laid out by the company panel in this case.

6 So either one could have very negative effects.
7 Your decision could have negative effects. And
8 Vogtle facing new setbacks would be a very negative
9 impact on the ratings.

10 VICE CHAIRMAN ECHOLS: Thank you.

11 MR. FETTER: Yes. Thank you, Commissioner.

12 BY MR. THOMAS:

13 Q And I just want to make sure I understand your
14 answer. I hear you say that you think it would be a
15 mistake, and I understand that.

16 But it is not your testimony, is it, that if
17 this Commission were to approve one of those recommended
18 ROEs in the nines, mid-nines, that it would -- that Georgia
19 Power would become junk bond status? That's not your
20 testimony, is it?

21 A (Witness Fetter) I indicate that it would move
22 towards junk bond status. I don't think it would reach it.
23 I think the ratings could weaken down to BBB-.

24 And I discuss in my rebuttal, I think
25 Mr. O'Donnell kind of treated any rating at BBB- or above as

1 all kind of very positive. I have a very different view.
2 When a utility has a rating at BBB-, then one unfortunate
3 setback could drive it into junk bond status.

4 So a major financial institution will think
5 twice before making major investments in a BBB- entity,
6 utility. Because if something -- if a storm came through,
7 if a hacking incident locked up the -- took all the
8 computers at Georgia Power, it could go from BBB- down into
9 junk bond basically in a moment's notice. And I talked
10 about Katrina. I talked about September 11th.

11 So major institutional investors would be very
12 wary of putting themselves at the risk of their
13 investment-grade investment going below investment grade in
14 the course of 24 hours. And it makes it much more difficult
15 to fund at that level.

16 Q I am a little confused by your answer. Because
17 earlier in questioning, I asked you if the Commission were
18 to adopt something in this range, would you expect a
19 downgrade, and I thought your answer was, no, you didn't
20 think you would --

21 A (Witness Fetter) That's exactly the opposite
22 of what I said.

23 Q Okay.

24 A (Witness Fetter) I referred back to the 9.21
25 as driving it down to BBB-. And I believe I said earlier

1 that it would weaken the ratings to BBB-. I did not think
2 they would go below the investment-grade dividing line. I
3 think the transcript will bear that out.

4 Q Okay. Well, I am sorry if I misunderstood you.

5 So your testimony is that you think it will
6 be -- definitely result in or most likely result in a
7 downgrade but not junk status?

8 A (Witness Fetter) I do not think it will be
9 junk bond status. I think there is a possibility it goes to
10 BBB-.

11 But one thing to realize is, if there is a
12 negative decision, the credit profile weakens. You know,
13 even if the ratings stay the same, then that BBB rating from
14 Fitch will be weaker than it was yesterday. The BBB+'s at
15 the two other entities would be weaker than they were the
16 day before. And it just makes them more susceptible to a
17 downgrade.

18 I think a downgrade would be very much
19 possible. But I am 100 percent certain that a negative
20 decision would weaken the credit profile, whether a
21 downgrade occurred or not.

22 Q Yes. And you would agree, though, that this
23 Commission listened to your recommendation in the 2019 case,
24 and a downgrade still occurred; right?

25 A (Witness Fetter) No. Actually, I supported

1 10.9 that was put forward by Professor Vanderweide.

2 Q Okay.

3 A (Witness Fetter) And the Commission ended up
4 settling at 10.5. I think there is a very strong
5 possibility that if Professor Vanderweide's view, which I
6 supported, had been adopted, I doubt that Fitch would be at
7 BBB right now. I think it would have been with its
8 compatriots at BBB+.

9 Q Even though Vogtle delays and overruns were one
10 of the largest reasons, would you not agree, that that
11 downgrade occurred?

12 A (Witness Fetter) I lost you there.

13 Q You wouldn't agree --

14 A (Witness Fetter) You said something about
15 larger reasons and a downgrade occurring.

16 Q I am sorry. Would you not agree that the
17 downgrade that occurred after the 2019 rate case was largely
18 impacted by Vogtle Unit 3 and 4 construction overruns and
19 delays?

20 A (Witness Fetter) Well, Vogtle was a very
21 important factor. Had the -- had the adopted ROE been at
22 10.9, then the financial status of the company would have
23 been stronger.

24 And so I expect -- certainly the downgrade to
25 BBB, Baa1 by Moody's had occurred a year before the rate

1 case. So that of course wouldn't have been affected. S&P
2 moved it to BBB+ after the rate case. Fitch moved it from
3 BBB+ down to BBB.

4 I expect that had Professor Vanderweide's 10.9
5 number been adopted that the Fitch rating down to BBB might
6 very well not have happened.

7 But I am quite sure that had the 9.21 of
8 Mr. Gorman been adopted, I would not be surprised to have
9 seen more than Fitch being at BBB.

10 Q And, Mr. Coyne, I would like to turn to your
11 testimony now. The models that you used -- discounted cash
12 flow, CAPM, risk premium -- they all -- they all take into
13 account interest rates; correct?

14 A (Witness Coyne) Two of them do directly. The
15 CAPM model and the risk premium model do. Interest rates in
16 the other models would be indirectly factored in, but they
17 are not direct inputs.

18 Q And can I ask you to turn to page 5 of your
19 testimony, starting at line 5.

20 A (Witness Coyne) In my direct testimony or my
21 rebuttal?

22 Q I am sorry. Your rebuttal testimony.

23 A (Witness Coyne) And on which page, please?

24 Q On page 5, starting around line 5, you state
25 that at the outset one must question analysis producing

1 results that are more than 300 basis points below any return
2 authorized for any electric utility in the last 40 years.

3 And just to be clear, staff's recommendation of
4 9.45 is not 300 basis points below the current average
5 return of approximately 9.35 percent; correct?

6 A (Witness Coyne) That's right. In that
7 sentence, I was referring to the recommendation from
8 Mr. Ellis.

9 Q Okay. And in fact staff's ROE recommendation
10 is slightly higher than the current authorized national
11 average of 9.35 percent; correct?

12 A (Witness Coyne) Now, when you say "national
13 average," could you tell me what you mean by that?

14 Q Sure. Can I get you to turn to the RRA
15 regulatory focus quarterly update and turn to page 8. And I
16 believe the next-to-last paragraph tells us that the
17 industry average ROE for vertically integrated electric
18 utilities was 9.35 percent.

19 Do you see that?

20 A (Witness Coyne) That's right. In the first
21 nine months of 2022.

22 Q Okay.

23 A (Witness Coyne) Is that your point of
24 reference?

25 Q That's my point of reference.

1 A (Witness Coyne) And your question is, is the
2 staff's recommendation higher than that national average?

3 Q Yes. It is slightly higher than the national
4 average; correct?

5 A (Witness Coyne) It is, yes.

6 Q Okay. Thank you.

7 A (Witness Coyne) That average of course is
8 calculated through the first nine months of the year. There
9 have been several decisions since then that are all
10 substantially higher than that national average, but that
11 was the national average as of that point in time.

12 Q And can I ask you to turn to page 9 of your
13 testimony, lines 6 and 7.

14 You talk about undermining investors'
15 perceptions of a constructive regulatory climate.

16 And you understand that the Commission must
17 balance ratepayer and investor interests; right?

18 A (Witness Coyne) I do. That's part of their
19 regulatory compact which they abide by.

20 Q Okay. And in order to do that, the Commission
21 must consider other factors beyond just investors'
22 perceptions of whether Georgia's supportive and constructive
23 regulatory climate; right?

24 A (Witness Coyne) Yes, that would be one of the
25 considerations. The broader public interest, of course, is

1 broader than that.

2 But insofar as setting a rate of return goes,
3 those requirements are quite specific as established by the
4 Bluefield and Hope Supreme Court decisions, which have three
5 standards associated with how you set the return.

6 Q But it isn't your testimony, is it, that if the
7 Commission awards an ROE below 11 percent and an equity
8 ratio below 56 percent that Georgia's automatically
9 perceived as unsupportive and unconstructive; correct?

10 A (Witness Coyne) Is your question as to how
11 investors would perceive the Georgia regulatory environment
12 if they were to award something lower than 11 percent on 56?

13 Q Right. Georgia would not then immediately be
14 considered unsupportive or an unconstructive regulatory
15 environment; correct?

16 A (Witness Coyne) I think that the ROE and
17 allowed return that the Commission sets is one factor in
18 terms of how the regulatory environment is perceived.
19 Timeliness of rate recovery, the overall parameters of the
20 R plan, for example.

21 There are many factors that go into how the
22 investors perceive the Georgia regulatory environment or any
23 other regulatory environment. But how they set the cost of
24 capital is a very important one.

25 Q All right. I understand that it is important,

1 but you would agree that that one factor alone, would you
2 agree that it would not automatically make Georgia be seen
3 as not a constructive regulatory environment if it was
4 somewhere below 11 percent and 56 percent equity ratio?

5 A (Witness Coyne) Well, it is -- your question
6 is a fairly general one, I think. It would depend on where
7 the Commission were to reach its determination. It has
8 earned this reputation over decades as being a constructive
9 regulator. I think a departure from that -- from that trend
10 would be looked at and reevaluated.

11 Georgia sits as just one of four states in the
12 country that enjoy an above-average regulation. So it is
13 not -- it is not taken lightly. I think they are amongst a
14 small number -- they are amongst a small number of
15 commissions that are viewed in that light.

16 I am not sure how much of a threshold they
17 would -- how much of a threshold difference it would require
18 before they would fall out of that. Those aren't my
19 judgments to make.

20 As you know, these are provided by the RRA, and
21 they take -- at least the ones that I cite, they take into
22 account other factors other than just ROE and capital
23 structure.

24 Q Well, on that point, in 2019, the Commission
25 approved an ROE that was lower than Georgia Power's

1 requested ROE, and the State continued to be seen as a
2 constructive regulatory environment; correct?

3 A (Witness Coyne) Yes, they did.

4 MR. THOMAS: Madam Chair, that concludes my
5 questions. Thank you.

6 MADAM CHAIR PRIDEMORE: Americans for
7 Affordable Clean Energy?

8 MR. GALLOWAY: No questions, Madam Chair.

9 MADAM CHAIR PRIDEMORE: ChargePoint?

10 MR. FYKES: No questions.

11 MADAM CHAIR PRIDEMORE: Commercial Group?

12 MR. JENKINS: I think staff's questioning was
13 close enough to what I was going to ask, so I won't
14 bore you with that. Thank you.

15 MADAM CHAIR PRIDEMORE: Thank you, Mr. Jenkins.
16 Georgia Association of Manufacturers?

17 MR. CHARLES JONES: No questions.

18 MADAM CHAIR PRIDEMORE: Georgia Coalition for
19 Local Governments?

20 MS. BROWN: No questions.

21 MADAM CHAIR PRIDEMORE: Georgia Interfaith
22 Power & Light?

23 MS. WHITFIELD: No questions.

24 MADAM CHAIR PRIDEMORE: GA Solar?

25 MR. MORELAND: No questions.

1 MADAM CHAIR PRIDEMORE: GASEIA?

2 MR. THOMASSON: I just have what I think is one
3 or two clarifying questions.

4 CROSS-EXAMINATION

5 BY MR. THOMASSON:

6 Q If the Commission approves an ROE center point
7 that's lower than what the company is requesting, is the
8 company's proposal that the upper band come down 100 basis
9 points with that approved ROE or that it stay at the
10 recommended 12 percent?

11 A (Witness Coyne) I am not sure that I can
12 answer that question. The company personnel might be better
13 able to do so.

14 MR. MARZO: Madam Chair, the witness panel
15 before are the ones responsible for the band. So
16 Mr. Thomasson should have directed that question to
17 the CFO of the company who was sitting on that panel.

18 MR. THOMASSON: Yeah, that's fair. I just
19 wanted to see if he could clarify.

20 MADAM CHAIR PRIDEMORE: Interstate Gas Supply?
21 I believe he said he had no more questions.

22 MADAM CHAIR PRIDEMORE: The Kroger Company?

23 MR. BOEHM: No questions, Your Honor.

24 MADAM CHAIR PRIDEMORE: MARTA?

25 MS. STURM: No questions.

1 MADAM CHAIR PRIDEMORE: Resource Supply
2 Management?
3 MR. CLARKSON: No questions.
4 MADAM CHAIR PRIDEMORE: Sierra Club?
5 MS. ARIZA: No questions.
6 MADAM CHAIR PRIDEMORE: SACE and Southface?
7 MR. DOWDY: No questions.
8 MADAM CHAIR PRIDEMORE: U.S. DoD?
9 CROSS-EXAMINATION
10 BY MS. MEDLYN:
11 Q Good afternoon. Emily Medlyn on behalf of the
12 United States Department of Defense and All other Federal
13 Executive Agencies.
14 A (Witness Coyne) Good afternoon.
15 A (Witness Fetter) Good afternoon.
16 Q Mr. Fetter, I have no questions for you.
17 A (Witness Fetter) Thank you.
18 Q All mine will be for Mr. Coyne.
19 Mr. Coyne, can you tell me what Georgia Power
20 specific characteristics weighed into your recommendation
21 for an ROE?
22 A (Witness Coyne) Sure. Well, I started with
23 the universe of value line companies that are regulated
24 electric utilities and -- as a basic profile.
25 And then from there, I winnowed them down into

1 a proxy group of 13 companies that looked most like Georgia
2 Power in terms of its overall business profile.

3 And then from there, I did further analysis
4 pertaining to both the business risk of Georgia Power and
5 the financial risk of Georgia Power. And on that basis,
6 determined that Georgia Power -- I also considered the
7 regulatory environment for the company.

8 And on that basis, I determined that there
9 wasn't -- there weren't significant enough differences from
10 Georgia Power vis-a-vis the proxy group companies to adjust
11 the ROE coming out of my financial models. So, therefore,
12 my recommendation was based on the average of those results.

13 Q Okay. Is expected return to investors driven
14 by relative risk?

15 A (Witness Coyne) Yes.

16 Q Okay. So higher risk would equate higher
17 expected return, and lower risk would equate to lower
18 expected return; is that correct?

19 A (Witness Coyne) Yes.

20 Q If a company's great performance reduces
21 financial risk, does that translate into a lower expected
22 return?

23 A (Witness Coyne) It is one of the factors that
24 investors consider. It is also -- I guess it is a fairly
25 broad question. But, yes, an effective management team in

1 running the company will do a better job of managing the
2 risks that it exposes -- it is exposed to. But investors
3 would also consider the risks that that management team is
4 up against.

5 So even a team that's doing an extraordinary
6 job in managing risk, if their risk -- if they are managing
7 a riskier company, may not get the benefit of the lower risk
8 than a company that had a lower risk -- overall lower risk
9 environment.

10 One of the ways to think about that is when you
11 consider a T&D company, for example, against a fully
12 integrated utility such as Georgia Power, they face
13 different risk opportunities, if you can call them that,
14 because it is a more complex utility to run than a pure T&D
15 company. So all that would get factored in.

16 Q Okay. Did you give consideration to Georgia
17 Power's record of strong performance in deriving your
18 recommended ROE?

19 A (Witness Coyne) Not specifically, because I
20 was looking at the -- well, what I was doing is I was
21 looking at the market-required return for a group of
22 utilities that are similar enough to Georgia Power as to
23 determine the appropriate market-required return.

24 An investor that would be trying to make a
25 decision between investing in Georgia Power, if they could

1 do so -- they can only really do so at the debt level unless
2 they are investing in Southern Company -- would look at that
3 performance. But it was not part of my analysis per se.

4 Q Would you characterize a lower rewarded return
5 due to relatively lower risk as punitive to investors?

6 A (Witness Coyne) Can you restate your question?

7 Q Would you characterize a lower rewarded return
8 on equity due to a relatively lower risk as being punitive
9 to investors?

10 A (Witness Coyne) Well, if you look across --
11 maybe to take your general question and make it more
12 specific, if I may.

13 If you look at the awarded returns for electric
14 utilities in the United States, T&D companies are typically
15 awarded ROEs that are about 35 basis points lower than fully
16 vertically integrated utilities on average.

17 And that is generally perceived as being
18 indicative of the risk differential between managing a T&D
19 company and managing a vertically integrated company.

20 So I think the general answer is that, yes, a
21 regulator should consider the overall risk profile of the
22 utility when they are setting the allowed ROE. If that's --
23 if that is your question.

24 Q Yes, thank you.

25 A (Witness Coyne) I hope I answered the question

1 you were asking.

2 Q You did. Thank you.

3 On page 8 of your testimony, lines 8 through
4 11, you --

5 A (Witness Coyne) And are you in my rebuttal
6 testimony?

7 Q Correct, yes, in your rebuttal testimony.

8 You state that ROEs that were considered
9 reasonable and appropriate for 2020, 2021, and even the
10 first half of 2022, are not currently reasonable in the
11 current market environment.

12 A (Witness Coyne) I see that, yes.

13 Q Okay. Can you tell me what the average ROE is
14 for the second half of 2022?

15 A (Witness Coyne) Well, in cross with staff just
16 now, we discussed the average awarded ROE. Is that your
17 question?

18 Q Correct, yes.

19 A (Witness Coyne) For the first nine months of
20 2022 for vertically integrated utilities is nine point --
21 year to date was 9.35 percent. And even there -- okay.
22 That's through the first nine months.

23 Q Right. My --

24 A (Witness Coyne) That sounds very current. But
25 since then, there have been nine decisions, and all those

1 decisions are much higher than that average looking
2 backward.

3 So it is always going to be a rear-view mirror
4 that we have. Current is looking forward when it comes to
5 setting the cost of equity. This can never do that for you.

6 Q Okay. But my question is -- because you had
7 said the first half of 2022, those ROEs may not be
8 reasonable now, given the current market environment.

9 So my question is, what is the average ROE for
10 the second half of 2022?

11 A (Witness Coyne) Well, of course, we are still
12 in November.

13 Q Correct.

14 A (Witness Coyne) So we don't know yet.

15 Q Right. Right.

16 A (Witness Coyne) Let me tell you that through
17 the first nine months, that number was 9.35 percent.

18 Q Okay.

19 A (Witness Coyne) And since then -- I will just
20 rattle you off the decisions that have occurred since then.
21 They have been 10.1 percent, 10.8 percent, 9.5, 10.25, 10.2,
22 10.3, and 9.9 percent, respectively.

23 So my view on this average is that it is a
24 rear-view mirror. It is looking backwards. When you
25 take -- and when you look at when these commissions made

1 these decisions, they were looking at stale market data at
2 that point in time. And so they could have been looking at
3 market data that was a year old.

4 And right now as we sit here, we know that
5 interest rates just in this year, for example, since April
6 when I filed my testimony, they are up over 100 basis points
7 since when I filed my direct testimony just in April.

8 So it is important in this discussion to
9 understand that it is a rear-view mirror, and when you are
10 setting the cost of equity, that requires a forward look.
11 And this is something that that can't do for you.

12 So that will never be a current indicator of
13 the cost of equity on a going-forward basis. It can only
14 tell us what the average was from -- from Commission
15 decisions that were always looking backward.

16 Q Okay.

17 MADAM CHAIR PRIDEMORE: Mr. Coyne -- excuse me,
18 Ms. Medlyn.

19 Can I ask you to repeat the ROEs that you
20 stated? You -- you did it with a speed, and I am
21 impressed by. But you started with 9.35.

22 MR. COYNE: Yes, Madam Chair. Nine point --
23 9.35 is the year-to-date average reported in RRA from
24 the exhibit that staff distributed, and that's for
25 vertically integrated utilities.

1 And since then there have been -- and I am
2 sorry. Since then there have been seven cases. And
3 those were 10.1 percent, 10.8 percent, 9.5, 10.25,
4 10.2, 10.3, and 9.9.

5 MADAM CHAIR PRIDEMORE: Thank you.

6 MR. COYNE: I think that's seven.

7 MADAM CHAIR PRIDEMORE: It is.

8 MR. COYNE: And I should also say in that
9 period of time that we have seen that the requested
10 ROEs are also going up substantially as the analysis
11 starts to reflect the new market data, both current
12 and also forward-looking market data, so...

13 My view is that, you know, we have reached the
14 turning point in capital markets, I think we can all
15 see. But we are now starting to see it being
16 reflected in these decisions.

17 BY MS. MEDLYN:

18 Q Okay. So my question was, the second half. So
19 from July 1st, 2022, to today, you don't have a number that
20 would reflect the average ROE for that --

21 A (Witness Coyne) From July through November?

22 Q For the second half of 2022?

23 A (Witness Coyne) No, it is not broken down that
24 way. It is broken down for 2021, year to date, and the last
25 12 months ending 9/30/2022.

1 Q Okay. So to follow up, I would assume, then,
2 you don't have a number for the average -- above-average ROE
3 from July 1st, 2022, to today; is that correct?

4 A (Witness Coyne) No, not without computing
5 that.

6 Q Okay. Thank you.

7 A (Witness Coyne) The closest I have in that
8 group for above average would be Florida Power & Light,
9 which now has triggered to 10.8 percent on a 59 percent --
10 59.6 percent equity ratio. I think of the -- when you say
11 "above average," you mean the above-average regulatory
12 commissions?

13 Q Correct. Just looking at your figure, I think
14 it is Figure 2 in your --

15 A (Witness Coyne) Correct. It would be one data
16 point, and that would be Florida Power & Light, which is
17 10.8 on 59.6.

18 Q Thank you. That's all I have.

19 A (Witness Coyne) You are welcome.

20 MADAM CHAIR PRIDEMORE: Okay. Georgia Watch?

21 MS. COYLE: Good afternoon, Commissioners. Liz
22 Coyle for Georgia Watch.

23 CROSS-EXAMINATION

24 BY MS. COYLE:

25 Q Good afternoon, Mr. Coyne and Mr. Fetter. Nice

1 to see you again. I just have a couple of quick questions.

2 Mr. Fetter, as chair of the Michigan Public
3 Service Commission, you have told us and we certainly know
4 that you were working to balance the interest of
5 shareholders and customers, ratepayers; is that correct?

6 A (Witness Fetter) And I do that as a
7 consultant, too, because I have represented consumer
8 advocates in that role.

9 Q Thank you. And so as you weighed aspects in
10 those capacities of rate cases in light of higher cost to
11 ratepayers -- so when there is a proposed rate increase on
12 the table in a rate case -- and you are looking at that in
13 the context of a requested higher profit for shareholders,
14 could you talk a little bit about how you would recommend a
15 commission evaluate the ROE as a component of a decision
16 that this Commission ultimately could make that would lower
17 the upward pressure on rates?

18 A (Witness Fetter) Wait. You are saying what
19 could the Commission do with regard to ROE that would lower
20 the impact?

21 You know, it is complicated because as
22 Mr. Coyne not only has said today, but he has filed two
23 documents in support, the market sets the required ROE as
24 opposed to a commission saying, you know, we are going to
25 set it at nine, four, or five, and the major institutional

1 investors, they will be happy with that. That's not how it
2 works. As Mr. Coyne has explained.

3 So you are asking if the Commission adopts an
4 ROE that's consistent with market forces, how can they --

5 Q Offset.

6 A (Witness Fetter) Well, I think that the
7 company already has put forward the idea of sharing at the
8 higher end, if the -- if the company acts more efficiently,
9 then does better than is expected, at some point, their
10 earnings go up and also there is sharing back with
11 consumers.

12 As far as how one can recognize market forces
13 and lower rates, that's what you are asking me?

14 Q To find that balance that you have recommended
15 to all commissions, that they look for the balance between
16 shareholder and ratepayer interest.

17 If the shareholders are granted the request for
18 a higher ROE, would you as a commissioner have, or would you
19 recommend this Commission deny other aspects of the proposed
20 rate increase to help put lower pressure on rates?

21 I mean, where is the balance? If the
22 shareholders get the higher ROE, where is the balance so
23 that the ratepayers aren't absorbing the full costs of the
24 higher rates?

25 A (Witness Fetter) Well, part of the balance is

1 that Georgia Power, it is my understanding, operates at
2 rates lower than the national average.

3 So just as staff has raised the concept of ROE
4 may be above the national average, right now rates at
5 Georgia Power are lower than the national average. So their
6 efficiency is already providing some benefits to consumers.

7 As far as taking an appropriate ROE number in
8 and of itself and then lowering rates below what that ROE
9 would create, I am -- I am kind of at wit's end how one
10 recognizes the appropriate ROE and then undercuts it in
11 flowing it into rates.

12 A (Witness Coyne) Could I offer a --

13 A (Witness Fetter) But my colleague here,
14 Mr. Coyne, might have an alternative.

15 A (Witness Coyne) I don't have a better answer
16 than he offered in terms of the balancing of interests; but
17 I think it is important to note, too, that when you think
18 about what flows through rates, it is the weighted average
19 cost of capital.

20 And the weighted average cost of capital is
21 actually declining in the company's rate request, from
22 7.9 percent that was approved in the last rate case to
23 7.7 percent in this rate case.

24 So the cost of capital is actually lower in
25 this rate case than it was in 2019 when you look at the

1 WACC, and it is the WACC that gets applied to rate base that
2 flows through to rates.

3 Q Okay. Yes, but you would both agree that in
4 this case what is not before this Commission is lowering
5 people's rates. It is how much -- how much to raise their
6 rates and how quickly and whether it is a 12 percent impact
7 almost immediately. You know, those -- that's sort of the
8 broader question. Not do they -- you are not -- they are
9 not being asked to lower Georgia Power's rates.

10 So as a commissioner, you would want to look
11 for that balance, would you not, to minimize the impact of
12 the rate increase on customers?

13 A (Witness Fetter) I mean -- I mean, clearly --
14 putting me back in my time as a commissioner, I considered
15 the arguments of all parties and then determined the best
16 decision reflecting the best public policy for the state.
17 And I expect that the five members here do that every day.

18 They listen to the company. They listen to
19 you. They listen to staff. They listen to all the other
20 intervenors. And they strike a balance that they feel
21 represents the best policy for the state, so...

22 COMMISSIONER MCDONALD: My former NARUC friend,
23 in your time as commissioner in Michigan, did your
24 commission ever issue an order lower than the ROE
25 requested by the investor-owned utility that you

1 regulated on?

2 MR. FETTER: You are saying did we ever?

3 COMMISSIONER MCDONALD: Yes, sir. All the ROEs
4 that were submitted to you by an investor-owned
5 utility, did you ever submit an order that was less
6 than what they asked for?

7 MR. FETTER: Well, that was a long time ago,
8 but I would guess the answer -- I would guess the
9 answer is yes.

10 And I also believe we never accepted an ROE
11 recommendation at the opposite end. It was striking
12 a balance that represented the best public policy for
13 the state of Michigan.

14 COMMISSIONER MCDONALD: Thank you.

15 MS. COYLE: Thank you. No further questions.

16 MADAM CHAIR PRIDEMORE: Redirect?

17 MR. MARZO: Just very briefly.

18 REDIRECT EXAMINATION

19 BY MR. MARZO:

20 Q Good afternoon, gentlemen. Now, you were asked
21 several questions related to national averages, and I am not
22 going to retread that ground here.

23 But I do want to ask you, Mr. Coyne, your
24 recommendation in this case is based upon an analysis that
25 was done specifically in Georgia Power; is that correct?

1 A (Witness Coyne) That's right.

2 Q Okay. And can you tell me that analysis --
3 based upon that analysis, what are you recommending in this
4 case?

5 A (Witness Coyne) 11 percent on a 56 percent
6 equity ratio.

7 Q And does the current economic climate also
8 provide additional support to your analysis?

9 A (Witness Coyne) Interest rates have come up
10 substantially, by over 100 basis points, since I did this
11 work. It was based on April market data.

12 So, if anything, the -- the interest rate in my
13 analysis that was projected was 3.4 percent for the 30-year
14 treasury yield, and that -- and that was projected for the
15 next three years.

16 And that 30-year bond today is at 3.7 percent.
17 So it is already 30 basis points higher than the projected
18 that I had used in order to emulate what I thought the
19 capital market environment would be for the company on a
20 going-forward basis.

21 And interest rates are already 30 basis points
22 higher than that projected rate, and they are projected to
23 go higher. So, if anything, I think the capital market
24 environment has rendered those results conservative based on
25 what has transpired since then.

1 Q Thank you, Mr. Coyne. And you were also asked
2 some questions by staff around whether the recommendation
3 they have fell around the national average and how that
4 related to being constructive.

5 And I just want to ask you, Mr. Fetter --
6 probably both this question. I know Mr. Fetter has been
7 here several times.

8 Is it your experience that this Commission has
9 ever used the national averages to set Georgia Power's ROE?

10 A (Witness Fetter) I have no memory of this
11 Commission, and from having appeared before probably 30
12 commissions, I don't think any commission has ever set their
13 internal ROE for their state utilities based on ROEs from
14 other states.

15 Q Hasn't the history of this Commission been in
16 this constructive framework, they have set ROEs that are
17 indeed higher, substantially higher than national average.
18 Is that right?

19 A (Witness Fetter) That's been my experience in
20 appearing here before.

21 Q Now, you were asked whether the decision in
22 2019 was considered to be constructive, by Mr. Thomas.

23 Can you tell me, Mr. Fetter, because you
24 testified in that case, was the ROE in that case set closer
25 to Dr. Vanderweide's recommendation of 10.9 percent, or was

1 it set closer to Mr. Gorman's recommendation of 9.2 percent?

2 A (Witness Fetter) It was well above
3 Mr. Gorman's and closer to Professor Vanderweide's.

4 Q Okay. You were asked some questions by
5 Mr. Thomas related to what I think he has marked as STF-116.
6 And it is the slide presentation.

7 A (Witness Fetter) Yes.

8 Q Slide 21. He referred you to -- now, am I
9 correct that what this shows is that -- and it is marked, in
10 fact, Improvements to Financial Plan.

11 Is what this shows, in fact, the improvement in
12 cash flow that you'd expect with the end of the construction
13 project and the end of the Vogtle penalties?

14 A (Witness Fetter) Yes.

15 Q And would you --

16 A (Witness Fetter) Because once depreciation
17 starts, then that is a major impact on cash flow.

18 Q Am I correct that this particular analysis is
19 done actually at the current -- company's current cost of
20 capital that's currently set by this Commission; correct?

21 A (Witness Fetter) Say that question again.

22 Q Yes. This current analysis, I believe, and the
23 footnote below indicates that it's actually been performed
24 at the company's current cost of capital?

25 A (Witness Fetter) Yes.

1 Q Okay. And would you expect that rating
2 agencies, as they look at Georgia Power Company, and they
3 determine how constructive this environment is, that they
4 have expectations that things like the Vogtle penalties and
5 the final closure of Vogtle and it going into service, those
6 are all things that they have factored into what they assess
7 as part of what would be expected to be cash flows and the
8 constructive environment here?

9 A (Witness Fetter) Yes. As I discussed with
10 Commissioner Echols, the rating agencies have a certain
11 point of view of how they see things proceeding, and they
12 factor that into their analysis. And that's why, if there
13 were major setbacks, it would -- it would have a major
14 impact on the rating agencies and their view going forward.

15 Q And is it fair to say to not see improvements
16 could in fact be, for lack of a better word, destructive to
17 what is considered to be a constructive regulatory
18 environment viewed by rating agencies?

19 A (Witness Fetter) I missed the beginning of the
20 question.

21 Q Yeah. My question was simply, would you agree
22 with me that the absence of improvements could in fact be
23 viewed as not constructive by rating agencies?

24 A (Witness Fetter) The absence of improvements
25 in cash flow?

1 Q In cash -- yes.

2 A (Witness Fetter) Yes. Yes, they have
3 expectations related to Vogtle going into service and the
4 cash flow that would increase. And so all of those would
5 change if there were further setbacks --

6 Q Okay.

7 A (Witness Fetter) -- at Vogtle.

8 Q And am I correct that could be a significant
9 qualitative factor in terms of considering this constructive
10 regulatory environment?

11 A (Witness Fetter) Both quantitative and
12 qualitative.

13 MR. MARZO: Thank you. Madam Chair, that's all
14 the redirect I have. I don't believe I have any
15 exhibits, but I do ask they get moved. Thank you.

16 MADAM CHAIR PRIDEMORE: All right. So moved.

17 MR. THOMAS: Madam Chair, I would also ask that
18 staff's exhibits be entered into the record.

19 MADAM CHAIR PRIDEMORE: So moved.

20 (Staff Exhibits Staff 116 through 118 were
21 admitted into evidence.)

22 MADAM CHAIR PRIDEMORE: The snack bar had to
23 close early. Sorry about that. The executive
24 secretary's office has something if you're hungry.

25 All right. That's it. You are dismissed.

1 thank you.

2 MR. FETTER: Thank you, Commissioner.

3 MADAM CHAIR PRIDEMORE: Good to see you

4 Mr. Fetter, Mr. Coyne.

5 MR. FETTER: Thank you, Madam Chair.

6 MR. COYNE: Thank you.

7 MADAM CHAIR PRIDEMORE: Next panel, Evans and

8 Legg.

9 MR. HEWITSON: Madam Chair, Georgia Power calls
10 to the stand the panel of Mr. Lee Evans and Mr. Larry
11 Legg. And before they sit down, if I could ask them
12 to stand and raise their hands.

13 Thereupon,

14 LEE EVANS,
15 LARRY LEGG,
16 having been duly sworn, testified as follows:

17 DIRECT EXAMINATION

18 BY MR. HEWITSON:

19 Q Mr. Evans, would you please state your full
20 name, your employer and your responsibilities for the
21 record.

22 A (Witness Evans) Lee Evans, Southern Company
23 Services, director of demand planning and analysis.

24 Q Mr. Legg, would you do the same, please.

25 A (Witness Legg) Larry Legg, Georgia Power
 Company, director of pricing and rates.

1 Q Gentleman, on November 18th of this year, did
2 you prefile or cause to be prefiled 23 pages of rebuttal
3 testimony in question-and-answer format?

4 A (Witness Evans) Yes.

5 A (Witness Legg) Yes.

6 Q Do you have any corrections that need to be
7 made to your prefiled rebuttal testimony?

8 A (Witness Legg) No.

9 A (Witness Evans) No.

10 Q If I were to ask you the same questions today
11 under oath, would your answers be the same as are set forth
12 in that prefiled rebuttal testimony?

13 A (Witness Evans) Yes.

14 A (Witness Legg) Yes.

15 MR. HEWITSON: Okay. Madam Chair, a copy of
16 the prefiled rebuttal testimony was provided earlier
17 to the court reporter, and I now ask that the
18 rebuttal testimony of Mr. Evans and Mr. Legg be
19 copied into the record as if given here today.

20 MADAM CHAIR PRIDEMORE: So moved.

21 (Whereupon, the prefiled rebuttal testimony
22 of Lee Evans and Larry Legg follows:)

23

24

25

**REBUTTAL TESTIMONY OF
LEE EVANS AND LARRY LEGG
ON BEHALF OF
GEORGIA POWER COMPANY**

DOCKET NO. 44280

I. INTRODUCTION

Q. PLEASE STATE YOUR NAMES, TITLES, AND BUSINESS ADDRESSES.

A. Lee Evans, Director of Demand Planning & Analysis for Southern Company Services, Inc. (“SCS”). My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

A. Larry T. Legg, Director of Pricing and Rates for Georgia Power Company (“Georgia Power” or the “Company”), 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

Q. MR. LEGG AND MR. EVANS, DID YOU PREVIOUSLY PRESENT DIRECT AND SUPPLEMENTAL DIRECT TESTIMONY AND EXHIBITS ON BEHALF OF GEORGIA POWER IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of our testimony is to respond to recommendations made by the Georgia Public Service Commission’s (“Commission”) Public Interest Advocacy (“PIA”) Staff and Intervenors as they relate to rate design and cost-of-service. The fact that we may not specifically address a particular recommendation made by PIA Staff or an Intervenor should not be construed as support for such position.

1 **Q. ARE YOU PROVIDING ANY EXHIBITS TO YOUR TESTIMONY?**

2 A. No.

3 **Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

4 A. As part of our longstanding commitment to meet our customers’ energy needs, Georgia
5 Power offers our customers an extensive portfolio of more than 40 individual electric
6 service base rate options from which to choose, with multiple options available for
7 customers of differing sizes and classes. These rate offerings, including the changes
8 proposed by Georgia Power in this rate case, will enable the Company to continue
9 providing customers with clean, safe, and reliable electricity at prices that are below the
10 national average. While a more thorough discussion of the issues we address on rebuttal
11 appears in the following sections of our testimony, here we provide a general summary of
12 our testimony with respect to a number of key issues.

13 *Residential Rates*

14 Notably, and for the avoidance of doubt, the Company is *not* proposing to discontinue the
15 Residential Service (“R”) tariff; rather, the Company proposes to make the rate unavailable
16 to new residential premises that establish service after December 31, 2022. Georgia Power
17 also opposes the structural changes to the R rate proposed by PIA Staff, as these changes
18 would fundamentally alter the rate for the more than 1.8 million customers currently taking
19 service under the rate without due consideration of this impact.

20 The Company’s proposal to close the R rate for new residential premises effective January
21 1, 2023, should be approved. This proposal is a logical step in the transition to more modern
22 rate structures, such as Time of Use Residential Demand (“TOU-RD”), with price signals
23 that more accurately reflect the cost of electric service for customers. To be clear, if the R
24 rate is closed to new premises, customers will still be able to choose from among any of
25 the Company’s residential rate options for which they qualify, in addition to TOU-RD as
26 the default residential rate. Contrary to the assertions of PIA Staff and certain intervenors,
27 the TOU-RD rate is designed to be revenue neutral and not cost customers more than the

1 R rate. Because the TOU-RD rate provides better price signals, customers are able to make
2 more informed decisions about their energy use and can save on their electric bills by
3 shifting usage or staggering the use of key appliances.

4 *Commercial and Industrial Rates*

5 The Company's commercial and industrial rates continue to be appropriately structured,
6 and the Company does not agree with the proposed changes to these rates. PIA Staff's
7 recommendation that customers on marginal rates should be assessed the fully embedded
8 cost of the Environmental Compliance Cost Recovery ("ECCR") tariff is fundamentally
9 inconsistent with how marginal rates like Real-Time Pricing ("RTP") are designed to
10 operate and should be denied. Fully embedded costs are recovered from the Customer
11 Baseline Load ("CBL") portion of the marginally priced rates, while marginal costs are
12 recovered from the marginal portion of the rates. To include fully embedded costs such as
13 ECCR in the marginal portion of the rates like RTP would undermine the rate structure and
14 significantly decrease the appeal of the rate to current and future customers. Altogether,
15 PIA Staff's recommendation to include ECCR in marginal RTP prices, as well as their
16 recommendation to recover ECCR costs on a per kWh basis rather than as a percent of base
17 revenue, results in an overall increase to the RTP tariffs of \$150 million. The Commission
18 should reject both recommendations. The Commission should also reject Department of
19 Defense Witness Blank's recommendation to modify the Company's criteria for the
20 reduction of CBLs for customers who install behind the meter generation because customer
21 generation does not permanently remove the customer's load and does not justify the
22 reduction of a customer's CBL.

23 *Community Solar*

24 The Commission should approve the Company's requested increase to the Community
25 Solar block prices as agreed to by PIA Staff, since the purpose of this program is to support
26 the development of renewable energy but does not guarantee bill savings. In addition, the
27 Georgia Coalition of Local Government's ("Coalition") proposed price reduction is
28 premised on a misunderstanding of how the program operates and should be rejected.

1 *Charge It Electric Vehicle Tariff*

2 The Commission should also approve the Charge It Electric Vehicle (“CIEV”) tariff, as
3 agreed to by PIA Staff, as an appropriately structured and time limited offering to
4 encourage the growth of electric vehicles (“EVs”) in Georgia.

5 *Cost-of-Service Study*

6 The Company’s cost-of-service study (“COSS”) continues to reasonably allocate the
7 Company’s revenue requirement across retail rates based on principles of cost causation.
8 Georgia Power’s continued use of a 12 coincident peak (“12-CP”) methodology to allocate
9 production costs is reasonable and appropriately recognizes the Company’s need to plan
10 and operate its system in every month of the year. Staff and Intervenor proposals to replace
11 the 12-CP method with an energy-based allocation method or summer-focused allocation
12 method are neither compelling nor justified.

13 *Parity Adjustments*

14 Finally, the Company is supportive of general movement towards parity but not the rate
15 specific adjustments proposed by PIA Staff or Georgia Association of Manufacturers
16 (“GAM”) Witness Pollock. Instead, the Company supports parity adjustments rooted in the
17 Company’s COSS that are made at the rate group rather than individual rate level.

18 **Q. HOW IS THE REMAINDER OF YOUR TESTIMONY STRUCTURED?**

19 A. Our testimony is organized as follows:

- 20 • Section II (pages 5 to 11) discusses proposed changes to residential rates;
- 21 • Section III (pages 11 to 14) discusses proposed modifications to commercial rates;
- 22 • Section IV (pages 14 to 18) discusses proposed changes to the Community Solar and
23 CIEV tariffs;
- 24 • Section V (pages 18 to 19) discusses the Company’s proposed Interconnection
25 Application Fee;

- Section VI (pages 19 to 20) discusses hourly interval data;
- Section VII (pages 20 to 22) discusses proposed changes to the COSS; and
- Section VIII (page 23) discusses proposed parity adjustments.

II. RESIDENTIAL RATES

Residential Service “R” Tariff

Q. PLEASE EXPLAIN THE COMPANY’S PROPOSED CHANGES TO THE R RATE.

A. As Mr. Legg states in his Direct Testimony, the Company proposes to update the R tariff to make the rate unavailable to newly constructed residential premises that establish service on Georgia Power’s electric system after December 31, 2022. This update will encourage residential customers to adopt more modern rate structures with price signals that more accurately and appropriately reflect the cost of electric service. However, the R tariff will remain available to residential premises for which electric service is established prior to January 1, 2023.

As part of its commitment to customer satisfaction, Georgia Power has actively promoted the variety of residential rate options it offers to help customers select the rate that best fits their needs. As a result, customer adoption of residential rate options such as the TOU-RD (also known as “Smart Usage”), TOU-PEV, Pay by Day (“PBD”), and FlatBill tariffs has increased significantly. Indeed, the number of residential customers who have chosen to participate in a time-of-use rate has increased by more than 250%. Many customers have demonstrated a preference for these rate plans, which are designed to provide customers with options that best meet their needs. By closing the R rate to new premises, the Company will continue to gradually transition new residential accounts onto the other rates within the Domestic Group that better align with the cost to serve customers.

1 **Q. IS PIA STAFF PROPOSING ANY MODIFICATIONS TO THE R RATE?**

2 A. Yes. PIA Staff proposes to eliminate the declining block rates during non-summer months
3 and move to a flat rate for all kilowatt hour (“kWh”) usage.

4 **Q. DO YOU AGREE WITH PIA STAFF’S RECOMMENDATION TO REPLACE**
5 **THE DECLINING WINTER BLOCK RATE STRUCTURE WITH A FLAT**
6 **ENERGY RATE?**

7 A. No. Notably, the Commission has declined to adopt this recommendation in each of the
8 last two rate cases and should continue to do so in this case. Although the price signal the
9 R rate sends is not as strong as more recent tariff designs, the Company originally designed
10 the R rate to reflect the seasonality of costs to serve residential customers. The inclining
11 price blocks in June through September appropriately reflect the fact that the Company’s
12 costs are higher in the summer months. Importantly, the inclining price structure provides
13 incentives for energy efficiency and conservation. The declining block structure in the
14 winter months recognizes that off-peak costs are generally lower and, therefore, provides
15 price signals to reflect this reality. The declining block structure provides an economical
16 option for customers choosing to use electric heating. The prices are set to more than cover
17 the Company’s marginal costs, and resulting revenues place downward pressure on rates
18 for all customers.

19 **Q. ARE THERE OTHER CONCERNS WITH PIA STAFF’S PROPOSAL TO**
20 **SIGNIFICANTLY MODIFY THE R RATE?**

21 A. Yes. PIA Staff is proposing significant modifications to the R rate without providing any
22 analysis or discussion of the impacts these changes would have on the large number of
23 customers who are currently on that rate. Currently, more than 1.8 million customers take
24 service on the R rate, and it is not clear that PIA Staff has considered how their proposed
25 modifications will impact these customers or what steps should be taken to educate
26 customers prior to the implementation of such changes. PIA Staff is proposing to
27 fundamentally alter the rate through which Georgia Power’s largest number of customers

1 are being served, without due consideration of the impact to those customers. Further, the
2 R rate design is antiquated and sends poor price signals to customers about the cost of the
3 electricity they consume, as compared to the Company's newer rate designs. Thus, it makes
4 no sense to fundamentally alter the longstanding R tariff while customers are transitioning
5 to more modern rates that more appropriately reflect the cost of electric service for
6 customers.

7 **Q. IS THE COMPANY PROPOSING TO ELIMINATE THE R RATE?**

8 A. No. The Company is *not* proposing to eliminate the R rate. Under the Company's proposal,
9 customers currently on the R rate will be able to remain on the rate. Customers currently
10 on the R rate who subsequently move to another existing premises will also be able to
11 remain on the rate. The Company is only proposing to close the R rate for new residential
12 premises that initially establish service with Georgia Power after December 31, 2022. This
13 incremental change in the availability of the R rate is a measured and logical step in Georgia
14 Power's gradual movement towards more modern rate designs that send price signals that
15 more appropriately reflect the cost of electric service for customers.

16 **Q. ASIDE FROM THE R RATE, WHAT OTHER RATE OPTIONS ARE AVAILABLE**
17 **FOR CUSTOMERS AT A NEW PREMISES?**

18 A. If the Company's proposal is adopted, customers at new residential premises can choose
19 from the Company's other residential rate options, which include TOU-RD, TOU-PEV, or
20 PrePay. Additionally, once those premises have twelve months of service history,
21 customers can also select the Company's FlatBill or Pay by Day rates.

22 **Q. DOES THE COMPANY HAVE ANY FEEDBACK FROM CUSTOMERS**
23 **REGARDING THEIR EXPERIENCE ON TOU-RD?**

24 A. Yes. Customer surveys have shown that, as compared to customers on the R rate, TOU-
25 RD customers are more satisfied with their rate and feel more knowledgeable regarding the
26 behaviors that can help them capitalize on their rate plan and reduce their energy bills.

1 These same surveys showed that TOU-RD customers had an overall higher satisfaction
2 score for Georgia Power as compared to R rate customers.

3 **Q. IS THE TOU-RD RATE INHERENTLY MORE COSTLY FOR CUSTOMERS**
4 **THAN THE R RATE, AS CLAIMED BY PIA STAFF AND INTERVENORS?**

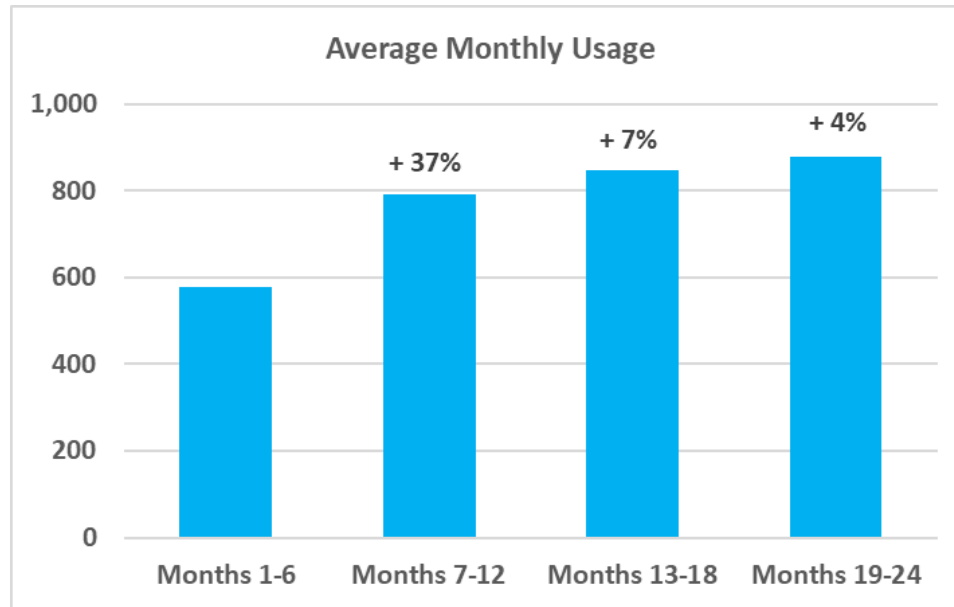
5 A. No. The TOU-RD rate is not designed to cost customers more than the R rate; rather, the
6 TOU-RD rate was designed to be revenue neutral for the average customer – meaning that
7 the average customer would pay the same annual bill amount on the TOU-RD rate as they
8 would on the R rate. In fact, because TOU-RD provides better price signals to customers,
9 they can make more informed decisions about their energy use and save on their electric
10 bills by shifting usage or staggering the use of key appliances. As a result, customers
11 receive more efficient economic signals regarding their usage and energy choices.

12 **Q. IS THE BILL COMPARISON NOTED IN PIA STAFF’S TESTIMONY AN**
13 **APPROPRIATE REPRESENTATION OF THE PRICE IMPACTS OF THE TOU-**
14 **RD RATE AS COMPARED TO THE R RATE?**

15 A. No. As new premises are added to the Georgia Power system, it can take anywhere from
16 one to two years for the premises’ monthly usage to normalize. This ramp-up period could
17 be due to numerous factors, including the timing of home construction, installation of
18 appliances, or occupancy. Because the bill comparisons that Staff highlight in their
19 testimony represent premises that are new to our system, the average monthly usage for
20 those premises is far below the level to which the usage will ultimately mature (see Figure
21 1). Therefore, the bill comparisons used by Staff are heavily skewed by extremely low
22 usage and therefore fail to tell a complete story.

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Figure 1



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As Figure 1 above demonstrates, a customer's average monthly usage will increase continually for the first 24 months of existence on Georgia Power's system. At least one intervening witness commented during their direct testimony that the TOU-RD rate is an effective rate for customers that demonstrate a "good load factor." By allowing the new premises to mature towards a normal usage level, customers at these new premises will greatly improve their load factors and have a better bill experience when comparing TOU-RD to the R rate.

10

Q. AS COMPARED TO THE R RATE, WHY ARE THREE-PART RATES – LIKE TOU-RD – MORE COST-REFLECTIVE?

11

12

A. Costs to serve our customers are divided into three components: (1) customer-related costs; (2) demand-related costs; and (3) energy-related costs. To ensure our rates most accurately reflect the cost-of-service, all three cost components should be accounted for within the design of a rate. As such, three-part rates, which include customer, demand, and energy related components, are the most cost-reflective rates because they appropriately account for each of the three cost categories. Conversely, when a rate, such as the R rate, lacks a

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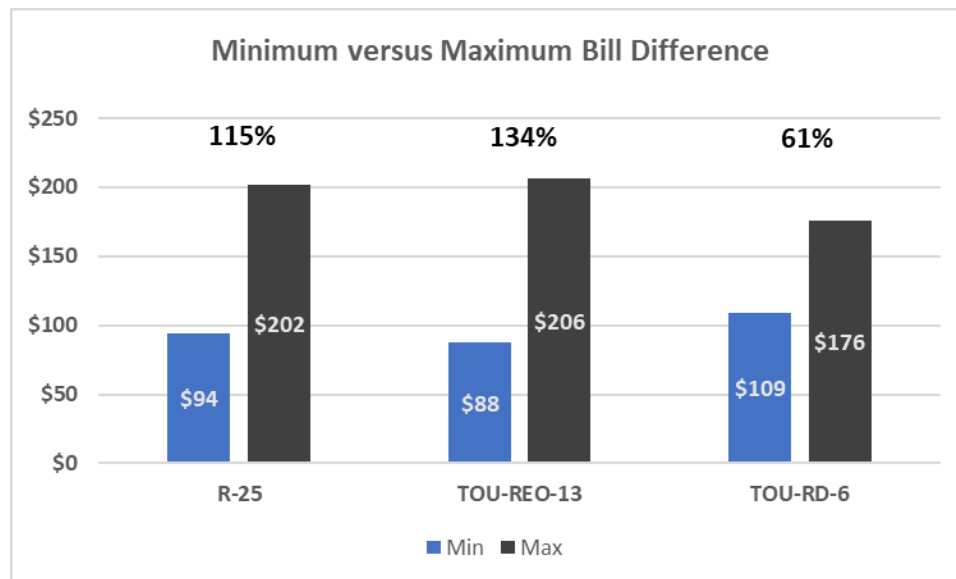
17

demand component, the demand-related costs of electric service must be recovered through the rate's energy component, which does not appropriately match the collection of revenues with how the Company incurs costs. The result is a less efficient price signal that results in less efficient use of the electric system by customers and higher prices overall.

Q. WHY IS THE TOU-RD RATE A BETTER DEFAULT RATE THAN TOU - RESIDENTIAL ENERGY ONLY ("TOU-REO") AS PROPOSED BY GSEIA, SEIA, AND VOTE SOLAR?

A. As described above, TOU-RD is a modern, three-part rate that sends price signals that more accurately and appropriately reflect the cost of electric service. In addition, the TOU-RD rate is more stable than the TOU-REO rate from a monthly billing standpoint, meaning that it has a smaller margin between minimum and maximum bills during an annual period. Figure 2 below provides an example of the bill volatility between the R, TOU-REO and TOU-RD rates for the average residential customer and shows that TOU-RD is much less volatile than either the TOU-REO or the R Rate when comparing the difference between minimum and maximum bills over a given year.

Figure 2



1 **Q. WHY IS IT APPROPRIATE TO INCREASE THE BASIC SERVICE CHARGE AS**
2 **PART OF THE COMPANY'S REQUEST?**

3 A. The increased basic service charge better aligns with the Company's costs to serve
4 customers. As stated by Mr. Legg during the Company's direct hearings, Georgia Power
5 has proposed to increase all traditional base rates on an equal percentage basis, including
6 rate elements. This includes the residential basic service charge, which recovers the
7 customer-related costs the Company incurs to serve a customer, regardless of the amount
8 of energy that customer may use. As proposed, the monthly increase to the basic service
9 charge would be approximately \$2.27 for a residential customer.

10 **Q. DOES THE COMPANY AGREE WITH STAFF'S PROPOSAL TO INCREASE**
11 **THE INCOME QUALIFIED SENIOR CITIZEN DISCOUNT BY THE AMOUNT**
12 **OF ANY INCREASE TO THE BASIC SERVICE CHARGE?**

13 A. Yes.

14 **III. COMMERCIAL RATES**

15 **Q. DO YOU AGREE WITH PIA STAFF'S RECOMMENDATION THAT**
16 **CUSTOMERS ON MARGINAL RATES SHOULD BE ASSESSED THE FULL**
17 **EMBEDDED COST OF THE ENVIRONMENTAL COMPLIANCE COST**
18 **RECOVERY ("ECCR") TARIFF?**

19 A. No. Staff's recommendation is fundamentally inconsistent with how marginal rates like
20 RTP are designed to operate. For RTP as designed, the Company's fully embedded costs
21 are recovered from the CBL portion of the rate, while marginal costs are recovered from
22 the marginal portion of the rate. The ECCR costs include coal combustion residual asset
23 retirement obligations ("CCR ARO") that are fully embedded costs incurred by the
24 Company independent of a customer's kWh usage. As such, they are appropriately
25 recovered through the CBL portion of marginally priced rates. To include fully embedded
26 costs such as ECCR in the marginal portion of the RTP rate would not only undermine the

1 rate structure, but also prevent these rates from actually functioning as marginal rates. The
2 hourly prices would no longer reflect marginal costs or real-time prices.

3 **Q. WHAT WOULD HAPPEN IF ECCR COSTS WERE ALLOCATED TO THE**
4 **MARGINAL PORTION OF RTP AND OTHER INCREMENTAL RATES?**

5 A. If ECCR costs, or other fully embedded costs, were allocated to the marginal portion of
6 RTP rates, RTP costs would increase by approximately \$150 million overall. A cost shift
7 of this magnitude would significantly decrease the appeal of the rate to current and future
8 customers. The RTP rate is a critical rate for large, economic development customers that
9 are considering locating, relocating, or expanding operations in Georgia. PIA Staff's
10 proposal undermines the principles of marginal rate design by dramatically altering the
11 allocation of ECCR costs within the RTP rate and would have a significant negative impact
12 on the Company's ability to help attract economic development opportunities to the state.

13 **Q. DOES PIA STAFF'S PROPOSED 50% MOVEMENT OF ECCR IN**
14 **INCREMENTAL RATES MITIGATE THE IMPACT OF STAFF'S**
15 **RECOMMENDATION?**

16 A. No. As described above, even an incremental move of 50% would have a dramatic and
17 negative impact on RTP customers by fundamentally changing the rate and undermining
18 the core principles of a marginal rate structure.

19 **Q. DOES GEORGIA POWER AGREE WITH DEPARTMENT OF DEFENSE**
20 **WITNESS BLANK'S RECOMMENDATION TO MODIFY THE CBL**
21 **REDUCTION CRITERIA?**

22 A. No. CBLs may be reduced when load originally represented in the CBL has been
23 permanently removed. Mr. Blank proposes to reduce CBLs when customers install
24 generation that runs "at least 6,000 hours" (68%) of the year, even though no load has been
25 removed. For almost one third of the year, the customer's usage on the system would be
26 the same as it was before the installation of the generation. Generation does not

1 permanently remove load, and therefore does not justify the reduction of the customer's
2 CBL.

3 Second, Mr. Blank criticizes the Company's requirement that a CBL reduction assessment
4 based on historical load is not permitted unless the customer stops taking service under the
5 RTP tariff for two years. The Company supports the requirement that a customer remain
6 off the RTP rate for two years before returning or requesting a CBL reduction, because
7 short term changes to a customer's usage should not result in the permanent conversion of
8 embedded load into marginal load on the RTP rate. The RTP tariffs include provisions to
9 revise the CBL as the result of actions like permanent equipment removal and energy
10 efficiency improvements, but the tariffs specifically prohibit CBL revisions due to
11 temporary factors such as economic downturns. Requiring customers who have not
12 removed load to stay off RTP for 24 months in order to set a new CBL preserves the
13 integrity of the RTP program and protects other customers from potential cost shifts that
14 might result from the premature revision of the CBL.

15 **Q. DOES THE COMPANY AGREE WITH WITNESS BLANK'S**
16 **RECOMMENDATION TO ALLOW RTP CUSTOMERS TO ALSO TAKE**
17 **SERVICE ON THE BACKUP ("BU") TARIFF?**

18 A. No. The purpose of the BU tariff is to enable customers who are not currently receiving
19 hourly marginal pricing to avoid yearly demand ratcheting, if their generation operates as
20 expected. Customers may receive this benefit *or* they may benefit from marginal pricing,
21 but not both.

22 **Q. DOES THIS MEAN RTP CUSTOMERS ARE NOT ABLE TO BENEFIT FROM**
23 **INSTALLING GENERATION?**

24 A. No. RTP customers that install and use generation receive the benefit of the Company's
25 marginal price for that hour. This is true when the customer avoids paying the marginal
26 price while operating above their CBL level, or when the customer receives a credit at the
27 marginal price when operating below their CBL level.

1 **Q. DOES THE COMPANY SUPPORT MODIFYING THE TERMS AND**
2 **CONDITIONS OF THE FIXED PRICE ALTERNATIVE (“FPA”) RATE AND**
3 **PRICE PROTECTION PRODUCT (“PPP”) OFFERING TO REMOVE**
4 **COMPANY DISCRETION REGARDING WHEN TO OFFER THESE RATES?**

5 A. No. The Company considers multiple factors when deciding whether to offer the FPA rate
6 and PPP offerings to customers. These factors include, but are not limited to, uncertainty
7 around environmental regulation, fuel markets, and other potential factors that could
8 impact the pricing of these offerings. Additionally, it is important for the Company to
9 maintain flexibility to act quickly and update PPP offerings to best reflect market
10 conditions, especially during times of fuel market volatility as have been experienced for
11 the last year. As a result, removing the Company’s discretion regarding when to offer these
12 products adds unnecessary risk that could be borne by other customers, since delays in
13 acting during volatile markets could result in the development of product offerings that do
14 not properly reflect pricing impacts.

15 **Q. DOES GEORGIA POWER SUPPORT MARTA’S REQUEST TO NOT APPLY**
16 **ANY INCREASES TO THE ELECTRIC TRANSPORTATION (“ET”) RATE?**

17 A. No. Georgia Power does not support MARTA’s request because it would result in a
18 revenue deficiency being spread to other customers. Georgia Power is sympathetic to
19 MARTA’s ridership challenges during the pandemic; however, these challenges are not
20 unique to MARTA and many other businesses have dealt with similar challenges.

21 **IV. COMMUNITY SOLAR AND CHARGE IT ELECTRIC VEHICLE TARIFFS**

22 *Community Solar*

23 **Q. WHAT IS THE PURPOSE OF THE COMMUNITY SOLAR TARIFF?**

24 A. The Community Solar tariff is a program that offers qualifying customers the opportunity
25 to support renewable energy and the development of solar power in Georgia by subscribing
26 to a portion of the output from local solar facilities. Every month, participating customers

1 pay a fee for a subscription block of the energy produced by Community Solar facilities,
2 and in return receive energy credits on their monthly bill that are based on the production
3 from those facilities. Additionally, the equivalent renewable energy credits (“RECs”) are
4 retired on the customer’s behalf. As noted in this Commission’s 2017 Order approving the
5 program, the Community Solar tariff is not intended to create bill savings for participating
6 customers, but rather, is targeted toward customers who are interested in supporting solar
7 but either do not want or are unable to install solar panels at their premises. The Company
8 currently operates three Community Solar facilities located near Athens, Augusta, and
9 Savannah.

10 **Q. ARE GUARANTEED BILL SAVINGS PART OF THIS PROGRAM?**

11 A. No. The Company does not guarantee or advertise the Community Solar program as a bill
12 savings opportunity. In some months throughout the year, the credit that participating
13 customers receive on their bill based on the solar facility’s production may exceed the
14 charge to participate, resulting in bill savings. However, as noted above, the purpose of the
15 program is to support renewable energy and the development of solar power in Georgia
16 and not to achieve bill savings.

17 **Q. WHAT DID THE COMMISSION APPROVE IN THE 2022 INTEGRATED**
18 **RESOURCE PLAN REGARDING THE COMMUNITY SOLAR TARIFF?**

19 A. The Commission approved updates to the Community Solar program to make it more
20 accessible to customers. More specifically, the Commission approved certain changes as
21 proposed by the Company, including the Income Qualified Community Solar Pilot. The
22 Commission did not approve the Company’s requested pricing change “to increase the
23 residential block charge to \$27.99 and to set the commercial option at \$29.99/month,”
24 electing instead to reserve the pricing decision for consideration in this rate case.

1 **Q. WHAT ARE THE PROPOSED CHANGES TO THE COMMUNITY SOLAR**
2 **TARIFF THAT ARE TO BE ADDRESSED IN THIS CASE?**

3 A. The Company proposes to update the pricing for the existing residential Community Solar
4 Charge from \$24.99 to \$27.99 per one kilowatt block in order to ensure that participants
5 are not subsidized by non-participants. In addition, following the Commission's approval
6 to expand the opportunity to participate in Community Solar to customers on the General
7 Service ("GS") tariff, the Company has proposed that the pricing for GS Community Solar
8 participants be set at \$29.99 per one kilowatt block.

9 **Q. WHY SHOULD THE COMMISSION REJECT PIA STAFF'S AND THE**
10 **COALITION'S RECOMMENDATIONS TO DECREASE THE PER KILOWATT**
11 **("KW") BLOCK PRICE FOR A COMMUNITY SOLAR SUBSCRIPTION?**

12 A. The Community Solar subscription price is designed to ensure that participating customers
13 do not shift costs to other customers when kilowatt hours reduce the monthly bills of
14 participating customers. As such, the Company has requested an increase in its subscription
15 rates for residential and commercial customers participating in Community Solar. Based
16 on the approved structure of the Community Solar program, a reduction in the price per
17 kW block of energy would leave costs unrecovered and, therefore, shift cost recovery to
18 non-participants.

19 In addition, the Coalition bases their reduction on the misguided premise that Community
20 Solar participants pay for rate riders like NCCR, ECCR, and fuel more than once.
21 Customers participating on the Community Solar rate still receive and pay for service on
22 their normal retail electric service rate and are still served from all energy resources
23 generating into or otherwise supplying the Company's system. When a participating
24 customer pays the subscription rate to participate in the Community Solar program, this is
25 a voluntary premium the customer opts to pay to support the addition of solar resources in
26 Georgia. This subscription affords the participating customer the opportunity to offset their
27 purchase of energy from Georgia Power by the amount of energy produced at the
28 Community Solar facilities. In turn, this energy credit offsets the purchase of delivered

1 energy applied to the customer's bill, including with respect to the components for ECCR,
2 NCCR, and fuel. Therefore, savings on the riders are achieved when the participating
3 customers' kWh usage is reduced by the Community Solar production amount.

4 The Company includes the rate riders as part of the calculation in setting the Community
5 Solar monthly charge because (i) that is consistent with how the R rate works and (ii) the
6 Company must ensure that the riders are not under recovered simply because the
7 participating customer's bill reflects fewer kWhs as a result of the energy credit applied
8 under the Community Solar program.

9 Finally, because the Community Solar participant still takes service on their normal retail
10 rate, participation in the Community Solar tariff does not automatically excuse the
11 customer from paying their share of NCCR, ECCR, and fuel.

12 **Q. WHY IS IT INAPPROPRIATE TO LOCK IN A COMMUNITY SOLAR**
13 **PARTICIPANT'S RATE FOR THE DURATION OF PROGRAM**
14 **PARTICIPATION AS PROPOSED BY THE COALITION?**

15 A. The Company designed program pricing to prevent cost shifting to non-participating
16 customers. The Company's costs and revenues are constantly changing. To hold a
17 customer's cost of participation static for the duration of their participation would lead to
18 inappropriate cost shifting to other participating and non-participating customers.

19 *Charge Electric Vehicle ("CIEV") Rider*

20 **Q. PLEASE DESCRIBE THE CIEV RIDER.**

21 A. Georgia Power is supporting the rapidly expanding EV market with a rider that is tailored
22 to provide affordably priced electric service and to encourage the growth of EVs in our
23 state. The CIEV rider will modify how the Power & Light tariffs price commercial EV
24 charging loads. Specifically, the new CIEV rider will modify the monthly billing demands
25 by using Billing Demand Adjustment Factors as specified in the tariff. CIEV is a temporary
26 rider that will expire either at the end of 48 months or when the rolling 12-month load

factor for the account reaches 15% or greater – whichever comes first. Participation is available to new, separately metered charging loads that are served on Georgia Power’s system after January 1, 2023.

Q. WHY IS IT INAPPROPRIATE TO OPEN THE CIEV RIDER TO EXISTING LOCATIONS AS RECOMMENDED BY SEVERAL INTERVENORS?

A. First, the CIEV rider was designed to incentivize the installation of new EV charging stations and opening this rate to existing customers would defeat the purpose of incentivizing *new* installations. Second, by limiting this tariff to new, separately metered premises, the Company designed the CIEV rider to avoid a cost shift among existing customers. If existing customers were permitted to participate on the CIEV rider, the reduced billing demand allocation in each year would necessarily shift demand costs to other customers. The Company does not support this type of cost shift and supports keeping the CIEV rider limited to new, separately metered premises in order to appropriately incentivize new EV charging installations without doing harm to existing customers.

V. INTERCONNECTION APPLICATION FEE

Q. PLEASE EXPLAIN WHY THE COMPANY PROPOSED AN INTERCONNECTION APPLICATION FEE IN SECTION G OF THE COMPANY’S RULES AND REGULATIONS FOR ELECTRIC SERVICE.

A. The Company proposed to introduce a one-time \$200 interconnection application fee that will be required for all customers seeking to interconnect a customer generating facility to the Georgia Power system. This fee is designed to recover costs associated with supporting the safe and reliable interconnection of a customer generator to the system and will help ensure that such costs are not borne by all other customers.

1 **Q. WOULD THE COMPANY CONSIDER MAINTAINING THE EXISTING \$5/KW**
2 **WITNESS TESTING FEE AS PROPOSED BY GSEIA, SEIA, AND VOTE SOLAR?**

3 A. No. The current \$5/kW witness testing fee was agreed to by settlement in 2017 as part of
4 the application of the RCB Framework to behind the meter solar. As settled to, this fee was
5 not implemented to fully recover the Company's cost to witness test new customer
6 generators smaller than 250 kW let alone the administrative costs to review, process, and
7 update the customer's account for the installation of generation at its premises. In contrast,
8 the Company's proposed \$200 one-time fee is designed to cover the application,
9 administrative costs, impact study fees and witness testing fees (where required) for new
10 customer generation. The cost to provide these services does not vary significantly based
11 on the size of the facility and the Company believes a flat, one-time fee is more appropriate
12 than the outdated \$5/kW witness testing fee.

13 **VI. HOURLY INTERVAL DATA**

14 **Q. DID THE COMPANY COMPLY WITH THE COMMISSION'S DIRECTION TO**
15 **EVALUATE CUSTOMER ACCESS TO HOURLY INTERVAL DATA**
16 **FOLLOWING THE 2019 RATE CASE?**

17 A. Yes. Consistent with the Commission's direction following the 2019 rate case, Georgia
18 Power worked with Staff to develop options for customer access to usage data and then
19 submitted recommendations to the Commission for approval. In addition, the cost to
20 provide additional options for access to customer usage data was directed to be deferred as
21 a regulatory asset and recovered in a future base rate proceeding, which the Company has
22 requested for recovery in this case.

23 **Q. IS GEORGIA POWER REQUIRED TO PROVIDE HOURLY USAGE DATA TO**
24 **ALL CUSTOMERS FREE OF CHARGE AS ASSERTED BY THE COALITION?**

25 A. No.

1 **Q. DO THE VAST MAJORITY OF CUSTOMERS HAVE ACCESS TO THEIR**
2 **HOURLY USAGE DATA?**

3 A. Yes. The Company made hourly usage data available to customers via My Power Usage
4 (“MPU”) in January 2022. This was the result of the hourly usage project approved by the
5 Commission. A limited group of customers are unable to use MPU; these include
6 customers who opt-out of an AMI meter and certain unmetered accounts. Special Service
7 Account and RTP customers are also not eligible for daily or hourly usage via MPU
8 because they are on more complex rates and not on AMI meters, but these customers can
9 access hourly interval usage data, along with additional features and options, by
10 subscribing to the Company’s Energy Direct website.

11 **Q. ARE ADDITIONAL CHANGES NEEDED TO THE PROVISION OF HOURLY**
12 **INTERVAL USAGE DATA?**

13 A. No.

14 **VII. PROPOSED CHANGES TO THE COSS**

15 **Q. DO YOU BELIEVE THAT OTHER ALLOCATION METHODOLOGIES IN**
16 **ADDITION TO THE COMPANY’S FILED 12-CP METHODOLOGY SHOULD BE**
17 **CONSIDERED BY THIS COMMISSION FOR THE ALLOCATION OF THE**
18 **CAPACITY COMPONENT OF THE PRODUCTION FUNCTION?**

19 A. No. When preparing for a rate case filing, Georgia Power considers other allocation
20 methodologies in addition to its historical preference of 12-CP. For this rate case, the
21 Company determined that 12-CP remains the most accurate and appropriate methodology.
22 As stated in Mr. Evans’ direct testimony, the 12-CP methodology incorporates the fact that
23 Georgia Power’s system is planned and operated for the purpose of serving load requests
24 every month of the year. Additionally, PIA Staff’s proposed methodologies not only impact
25 the allocation of costs in base rate cases, but also may impact the allocation of fuel costs in
26 the Fuel Cost Recovery docket. The trade-off between the level of Production fixed
27 investment and the variable cost of producing a unit of output is one primarily made

1 between base capital costs and fuel costs. Altering the allocation of Production capital costs
2 with such a complex calculation would necessitate a similar alteration to the allocation in
3 the Fuel Cost Recovery docket. Recognizing the current, approved allocation of fuel costs
4 in the Fuel Cost Recovery docket, the Company continues to support the 12-CP
5 methodology as the most appropriate Production allocator. It has been employed by
6 Georgia Power for allocating production capacity-related costs since 1989, and as such,
7 has therefore influenced present rates.

8 **Q. ARE PIA STAFF'S RECOMMENDATIONS CONSISTENT WITH THEIR 2019**
9 **RECOMMENDATIONS TO CHANGE HOW THE COMPANY ALLOCATES**
10 **GENERATION PLANT PRODUCTION COSTS?**

11 A. No. Staff is recommending energy-based allocation methods in this case, which are
12 substantially different from the "up to" 8-CP method proposed by PIA Staff in the last case.
13 If PIA Staff's recommendation had been adopted in the last case, it would be wholly
14 inappropriate to pivot to the other end of the spectrum so drastically in this case. Adopting
15 PIA Staff's vacillating recommendations in the 2013 and 2019 cases, and now this current
16 rate case, would have resulted in great swings in parity results from case-to-case. To depart
17 from using 12-CP as an allocator for Production cost, especially without compelling
18 evidence to do so, could cause significant and unexpected disruptions to customer bills.

19 **Q. WOULD THE COMPANY CONSIDER MOVING TO A 4-CP OR SUMMER PEAK**
20 **PRODUCTION COST ALLOCATION METHOD AS RECOMMENDED BY**
21 **INTERVENORS?**

22 A. No. The generation planning for Georgia Power's system is driven and influenced by non-
23 summer periods in addition to summer peaks. Georgia Power utilizes Expected Unserved
24 Energy ("EUE") in its determination of the optimal reserve margin for both Summer and
25 Winter seasons. A pure summer peak or 4-CP allocator is an oversimplification of the
26 Company's generation planning process. If one were to use a pure summer peak allocator,
27 this could create unstable, unbalanced, and inequitable cost allocation in which some rate
28 groups receive little if any Production demand cost allocation whatsoever. An example of

1 this could be if the pure summer peak allocator for that year occurred in daytime hours
2 such that there was no subsequent cost allocation to outdoor lighting. The ongoing capacity
3 needs of Georgia Power are heavily driven by winter needs and to not recognize or allocate
4 costs based on winter loads would, therefore, be inappropriate.

5 **Q. WHY IS THE 12-CP METHOD THE MOST APPROPRIATE WAY TO**
6 **ALLOCATE THE COMPANY'S PRODUCTION COSTS?**

7 A. A 12-CP demand is defined as the sum of the highest kW load for the Company in each
8 month of the 12-month period divided by twelve. At the jurisdictional, class, or rate group
9 level, 12-CP is the respective coincident demands at the time of the monthly system peaks.
10 Using this allocator ensures that the coincident load burden placed on the system by a
11 jurisdiction, class, or rate group is allocated an appropriate share of the costs of the system.

12 The Company's adoption of seasonal planning further reinforces the appropriateness of the
13 12-CP approach. The Company must plan to have sufficient generation to serve its
14 customers in all twelve months of the year and the 12-CP method appropriately captures
15 the summer and winter peaks targeted through seasonal planning. The summer and winter
16 reliability planning of the Company further underscores that no one month or season is
17 adequate at representing the coincident impact of customers on system capacity. Georgia
18 Power forecasts to remain a summer peaking utility. While the IRP identified winter
19 reliability concerns, the Company's rate designs remain appropriate to address the
20 forecasted peak loads and higher marginal costs that occur in summer months.

21 In addition, as stated in Mr. Evans' Direct Testimony, the 12-CP allocation methodology
22 has been used in every COSS study filed by the Company with this Commission since
23 1989. Further, the 12-CP method has been one of FERC's preferred allocation techniques
24 for determining wholesale jurisdictional obligations, and it has been used by the Company
25 in its filings before FERC. It has proven to be a common and popular allocation technique
26 employed in numerous retail filings before many state commissions throughout the United
27 States. It is a straightforward methodology, has a strong cost causative relationship, and
28 has a history of providing stable and sound results.

1 **VIII. PARITY ADJUSTMENTS**

2 **Q. DOES THE COMPANY SUPPORT MOVEMENTS TOWARD PARITY AMONG**
3 **RATE GROUPS?**

4 A. Yes. The Company has made movements toward parity in previous rate cases based on
5 PIA Staff's recommendation. In fact, since 2010, all of Georgia Power's rate groups have
6 moved toward parity or maintained relative parity. While the Company supports movement
7 towards parity, the Company does not support the parity adjustments outlined in the
8 testimony of Mr. Pollock on behalf of GAM or the testimony of the Barber, Deitchman,
9 Watkins panel for PIA Staff. Any adjustments toward parity should be based upon the
10 COSS presented in Exhibit LPE-1 filed by the Company in the rate case filing. The
11 precision of a COSS and the accuracy of the results are greatly impacted by the number of
12 customers and the amount of load in each rate. The smaller the number of customers and
13 the smaller the amount of load in a particular rate, the lesser the potential accuracy of the
14 results associated with that rate. Some rates have very limited participation and may
15 produce volatile rates of return and parity results in cost-of-service studies for different
16 time periods. With this in mind, the Commission should consider the cost-of-service to the
17 eight rate groups instead of by individual rates.

18 **IX. CONCLUSION**

19 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

20 A. Yes.

1 MR. HEWITSON: And with your permission, I
2 would like to ask Mr. Legg to summarize the testimony
3 of the panel.

4 MADAM CHAIR PRIDEMORE: Go ahead. Thank you.

5 A (Witness Legg) Good afternoon, Madam Chair and
6 Commissioners. Mr. Evans and I thank you for the
7 opportunity to be here today.

8 We are here today to respond to recommendations
9 made by PIA staff and intervenors as they relate to rate
10 design and cost of service. There were a lot of
11 recommendations made, and we address the majority of them in
12 our testimony, but not all.

13 The fact that we may not specifically address
14 particular recommendations made by staff or an intervenor
15 should not be construed as support for such position.

16 As we testified in our direct case, Georgia
17 Power is committed to meeting our customers' energy needs by
18 offering an extensive portfolio of more than 40 individual
19 electric service base rate options from which to choose with
20 multiple options available for customers of differing sizes
21 and classes.

22 These rate offerings, including the changes
23 proposed by Georgia Power in this case, will enable the
24 company to recover costs in a fair and reasonable manner
25 that better aligns the prices customers pay with the costs

1 that drive them in order to continue providing customers
2 with clean, safe, and reliable electricity with prices that
3 remain below the national average.

4 Regarding the company's residential rate
5 offerings, the company continues to propose to make the
6 residential service or R rate unavailable to new residential
7 premises that established service after December 31st, 2022.

8 As we discussed in the 2019 rate case and again
9 in this case, our proposal regarding the R rate is a logical
10 step in the transition to more modern rate structures such
11 as TOU-RD with price signals that more accurately reflect
12 the cost of electric service for customers.

13 To be clear, if the R rate is closed to new
14 premises, all residential customers will still be able to
15 choose from among any of the company's residential rate
16 options for which they qualify.

17 Georgia Power opposes staff's recommendations
18 to modify the declining winter block rate structure in the
19 R rate. This would fundamentally alter the rate for the
20 more than 1.8 million customers currently taking service
21 under the R rate without due consideration of the impact of
22 this change on customers.

23 Contrary to the assertions of staff and certain
24 intervenors, the company's TOU-RD rate is designed to be
25 revenue neutral compared to the R rate.

1 Because the TOU-RD rate provides stronger and
2 more accurate price signals than the R rate, customers can
3 make more informed decisions about their energy use and can
4 save on their electric bills by shifting usage to a
5 different time of day or staggering the use of key
6 appliances.

7 The company provides a variety of
8 communications and tools for customers on TOU-RD to help
9 them get the most benefit out of the rate.

10 The company's commercial and industrial rates
11 continue to be appropriately structured, and the company
12 does not agree with the proposed changes to these rates.
13 The staff recommendation that customers on marginal rates
14 should be assessed the fully embedded costs of the ECCR
15 tariff is fundamentally inconsistent with how marginal rates
16 like RTP are designed to operate.

17 Fully embedded costs are recovered from the
18 customer baseline load or CBL portion of the marginally
19 priced rates, while marginal costs are recovered from the
20 marginal portion of the rates.

21 To include fully embedded costs such as ECCR in
22 the marginal portion of rates like RTP would undermine the
23 rate structure and significantly decrease the appeal of the
24 rate to current and future customers.

25 Altogether, staff recommendation to include

1 ECCR and marginal RTP rates or RTP prices as well as their
2 recommendation to recover ECCR costs on a per-kilowatt-hour
3 basis rather than as a percentage of base revenue results in
4 an overall increase to the RTP tariffs of approximately
5 \$150 million. The Commission should reject both
6 recommendations.

7 The Commission should also reject Department of
8 Defense Witness Blank's recommendation to modify the
9 company's criteria for reduction of CBLs for customers who
10 install behind-the-meter generation because customer
11 generation does not permanently remove the customer's load
12 and does not justify the reduction of the customer's CBL.

13 The Commission should approve the company's
14 requested increase to the community solar block prices,
15 which were designed to ensure that participating customers
16 do not shift costs to other customers.

17 The purpose of the community solar program is
18 to support the development of renewable energy, not to
19 guarantee bill savings, and the company has appropriately
20 designed program prices to ensure the participants are not
21 subsidized by nonparticipants.

22 With this in mind, the Georgia Coalition of
23 Local Governments' proposed price reduction is premised on a
24 fundamental misunderstanding of how the program operates and
25 should therefore be rejected.

1 The Commission should also approve the
2 charge-it electric vehicle rider as an appropriately
3 structured, time-limited offering to encourage the growth of
4 electric vehicles in Georgia by incentivizing the
5 installation of new EV charging stations.

6 Opening this rate to existing customers would
7 defeat the purpose of incentivizing new installations.
8 Moreover, if existing customers were permitted to
9 participate in the charge-it rider, the reduced billing
10 demand allocation in each year would necessarily shift
11 demand cost to other customers.

12 Keeping the charge-it rider limited to new
13 separately-metered premises as proposed by the company will
14 appropriately incentivize new EV charging installations
15 without harming existing customers.

16 Therefore, the Commission should reject
17 intervenor recommendations to expand charge-it to existing
18 EV installations.

19 The company's cost of service study continues
20 to appropriately allocate the company's revenue requirement
21 across retail rate groups based on principles of cost
22 causation.

23 Georgia Power's continued use of a
24 12 coincident peak or 12-CP methodology to allocate
25 production costs is reasonable and appropriately recognizes

1 the company's need to plan and operate its system in every
2 month of the year.

3 Staff and intervenor proposals to replace the
4 12-CP method with an energy-based allocation method or
5 summer-focused allocation method are neither compelling nor
6 justified and should, therefore, be rejected by this
7 Commission.

8 Finally, the company is supportive of general
9 movement towards parity but not the rate-specific
10 adjustments proposed by staff or Georgia Association of
11 Manufacturers' Witness Pollock.

12 Instead the company supports parity adjustments
13 rooted in the company's cost of service study that are made
14 at the rate group level rather than the individual rate
15 level.

16 In summary, Georgia Power's rate offerings,
17 including the changes we propose in this case, will enable
18 the company to meet the evolving energy needs of its
19 customers and to continue providing them with the clean,
20 safe, reliable and affordable electric service that they
21 deserve and expect.

22 We understand that customers consider many
23 factors when choosing their electric service rates such as
24 economics, price risk, and bill stability.

25 With this in mind, we -- the company's

1 recommended portfolio of rates in this case maintains
2 attractive rate options for customers, helps move toward
3 greater rate modernization for the benefit of the customers
4 and allows the company to appropriately collect the costs of
5 electric service.

6 The company must continue to modernize its rate
7 offerings to be cost reflective, take advantage of new
8 technology, and adjust to changing customer behaviors. Many
9 of the changes proposed by staff and intervenors do not
10 similarly share these goals.

11 Changes the company proposes to our rate
12 designs will allow us to continue offering a diverse
13 portfolio of rate options to reasonably meet the energy
14 needs of our customers.

15 Thank you for your time and attention.

16 MR. HEWITSON: Madam Chair, the witnesses are
17 available for questions from the Commission as well
18 as cross-examination.

19 MADAM CHAIR PRIDEMORE: Thank you.

20 VICE CHAIRMAN ECHOLS: Mr. Legg.

21 MR. LEGG: Yes, sir.

22 VICE CHAIRMAN ECHOLS: As we have done IRPs
23 through the years, we have created programs. Some
24 have worked. Some have not. And every three years
25 we get a chance to make the good ones better and

1 throw out the bad ones.

2 Is that kind of how it does?

3 MR. LEGG: Yes, that's right, Commissioner.

4 VICE CHAIRMAN ECHOLS: So the TOU-RD rate --
5 and I have been -- you know I have been a fan of the
6 electric vehicle time-of-use rate and their
7 traditional time-of-use rate; right? I have asked
8 you this every time you have been in the chair.

9 MR. LEGG: Right.

10 VICE CHAIRMAN ECHOLS: The TOU-RD rate, you
11 mentioned that the company was giving tools to the
12 customer. You just said that. Tools to the customer
13 to be able to be successful on the rate.

14 What do you mean by tools? What tools are you
15 referring to?

16 MR. LEGG: Specific to the TOU-RD rate or any
17 other residential rate offering, we actually -- as
18 you know, Commissioner, we have our online My Power
19 Usage.

20 Customers can sign up, sign into their account
21 online. They can see their hourly usage. It is
22 after the fact. It is obviously not in real time.
23 That would be very, very costly.

24 But it is, you know, 24 to 48 hours later,
25 customers can see their actual hourly usage for each

1 hour of the month. So that's one of the tools that
2 we refer to.

3 We would also -- I also refer to the
4 information that we send to customers. If they sign
5 up for a rate like time-of-use residential demand, we
6 will e-mail that customer. If we don't have an
7 e-mail address, we will send a letter explaining how
8 the tariff works, different ways they can save energy
9 on the bill.

10 In addition to our website, we have a video on
11 the website that explains each of the different
12 residential rate offerings, how customers can save
13 money.

14 Right before the summer season, for rates that
15 have a summer differentiation like TOU-RD, we will
16 send out a postcard or an e-mail to customers
17 reminding them that summer is coming. Things like
18 that. So those are the types of tools I was
19 referring to.

20 VICE CHAIRMAN ECHOLS: Would you agree that,
21 you know, if you look at the website, and you're
22 getting data after the fact, that it -- you may have
23 hit a threshold that could impact your bill?

24 MR. LEGG: Yes. Yes. Absolutely.

25 VICE CHAIRMAN ECHOLS: Are you familiar -- I

1 guess in the last -- in the last hearing, I talked
2 about price signals and the fact that the TOU-RD rate
3 doesn't provide a realtime price signal to the
4 customer, like the clock; right? Two o'clock, I know
5 that rates are going up.

6 And so I have been searching far and wide
7 around the world for some signal that could help us
8 with the TOU-RD rate.

9 And I have -- I am glad to report that I have
10 found a signal. And I am wondering if you have seen
11 it. It is a box that the French use. It is called
12 "Tempo." And this box has six lights on it.

13 And these lights start out at blue, and then
14 they go to white and then red and blinking red. And
15 this box is mounted beside your thermostat.

16 And when you are -- as those lights are going
17 off, you know -- this is for a TOU rate. You know
18 you are getting to a critical point when you hit red.
19 And if you are blinking red, you better take evasive
20 action or you are going to -- you are going to, you
21 know, basically get into this higher-demand charge.

22 Are you familiar with the Tempo unit that the
23 French have used before?

24 MR. LEGG: I am not familiar with the Tempo
25 unit. I have seen similar types of units in the past

1 that had color coding to indicate different levels of
2 usage.

3 I am familiar with a device here that is
4 available called "Sense." And it is actually a
5 device that you can put in your -- I guess, next to
6 your electric panel at home.

7 There is an app that you can look at. It shows
8 the realtime usage for customers, you know, so you
9 can see what you are instantaneously using in your
10 home based on what is going through your panels. So
11 I am familiar with that.

12 VICE CHAIRMAN ECHOLS: Would the customer be
13 able to get a notification on that as it -- can
14 you -- you know, can you set thresholds so that I am
15 getting an alert? Like the Tempo unit would have the
16 white light; now I am at the red light.

17 Would you have that ability with the Sense
18 program?

19 MR. LEGG: I haven't looked at that
20 specifically, but it is a pretty good interface. So
21 it would not surprise me if it had alerts. And in
22 fact, it might surprise me if it didn't have alerts
23 on that. But I haven't checked that specifically.

24 VICE CHAIRMAN ECHOLS: Sorry. Mr. Legg, all I
25 am asking in this particular rate case is that we

1 perfect this TOU-RD before we harden it, that we use
2 this Sense device that you have got or something like
3 the French Tempo device or something to give
4 customers the signal.

5 Let's make the rate optional and not default
6 people to it. But if they want to go on it, and I
7 hope they -- you know, I mean, it is my hope while I
8 am here at the Commission that we get more and more
9 people understanding the value of the energy that
10 they are using.

11 I love the prepay, that customers get the text
12 messages. I -- we are making smarter customers. But
13 the TOU-RD rate is too difficult to figure out
14 without a Sense device or a Tempo device.

15 And what I am hoping that my colleagues will
16 do, or in the stipulation, is that we will delay the
17 mandatory effect of this rate and that we will come
18 up with, you know, something like the Tempo device.
19 And I am understanding that it may be about a \$50
20 device. Something like that.

21 But your Sense device, it fits more into the
22 modern day; right? On the phone as opposed to a box
23 with lights on it.

24 I mean, do you feel like something like that
25 would allow the customers to take control of the

1 rate, to be successful with the rate, to avoid the
2 surprises that the blinking red light would give?

3 MR. LEGG: It's possible, Commissioner. And
4 like you, we always are concerned about how our
5 customers use electricity. And as you know, through
6 myriad of proceedings over here over the years, we've
7 worked hard to make sure our customers understand
8 their rates, understand what energy efficiency
9 options are available to them. We've rolled out a
10 lot of energy efficiency programs and things like
11 that.

12 So certainly, that's something that we will
13 continue to do is continue to try to improve on the
14 offerings to our customers. We can look into the
15 Tempo device. The Sense device that I looked up, I
16 believe was a little more expensive, it was about
17 \$300. That may be because of the interface
18 difference. But certainly we can look into that.

19 I do want to make sure that I'm clear, that I'm
20 communicating how the rate works. You're correct
21 that, once a customer sets a peak demand, that will
22 be their -- their demand charge will be based on that
23 for the month. That's very similar to the way our
24 commercial or industrial rates with demand charges
25 work. Customers don't necessarily -- may or may not

1 necessarily know what hour they're setting their
2 demand, but whatever the peak is, that's what they're
3 charged on.

4 But from a timing standpoint, there is still,
5 in the TOU-RD rate, the energy price is on peak/off
6 peak, so there is a signal, you know, to avoid the
7 2 to 7 p.m. window on summer afternoons. So that is
8 part of the TOU rate design for residential demand as
9 well.

10 And, again, the information that we've shared
11 with customers, we've worked hard to make sure they
12 understand. I know you are familiar, but the survey
13 that we did earlier this year, we actually surveyed
14 customers and asked them, on several different
15 residential rates, you know, how satisfied are you
16 with your rate? Do you understand your rate? Those
17 types of things.

18 The -- and when we're talking about TOU-RD
19 here, as you know, we're talking about making it the
20 default versus the R rate, which is the default now.

21 When we asked customers on the TOU-RD rate, do
22 you have enough information? Do you understand your
23 rate well enough to be able to understand how to save
24 energy on it? That actually scored -- those
25 customers on that rate answering questions about the

1 rate they were on scored significantly higher than
2 customers on the R rate asked the same question.

3 VICE CHAIRMAN ECHOLS: I don't mean to be
4 cynical and skeptical here. But I would suggest
5 those customers don't know what they don't know, that
6 they aren't able to -- if they don't have these
7 lights or they don't have -- if they don't have the
8 signal, then they probably aren't getting as much out
9 of it as they could, and maybe they -- maybe they
10 don't know that.

11 And so they may be satisfied. I mean, y'all
12 have a lot of satisfied customers. I mean, you're
13 getting awards for customer satisfaction. That's a
14 good thing.

15 But I just feel like that, you know, we tried
16 this. It didn't -- it didn't perform, at least to my
17 liking, and I think we need to go back to the drawing
18 board before we -- before we make it mandatory.

19 So thanks for considering that. I would
20 appreciate an update on the Sense device, get a
21 demonstration on the product, or I'm even willing to,
22 you know, to try it myself. But if you could get me
23 an update on that. Thank you.

24 MR. LEGG: Sure. Thank you, Commissioner.

25 VICE CHAIRMAN ECHOLS: Thank you, Madam Chair.

1 MADAM CHAIR PRIDEMORE: Any other questions
2 from Commissioners?

3 (No response.)

4 MADAM CHAIR PRIDEMORE: Georgia Public Service
5 Commission?

6 MR. THOMAS: Thank you, Madam Chair. I don't
7 have a lot. Commissioner Echols asked a lot of my
8 questions.

9 CROSS-EXAMINATION

10 BY MR. THOMAS:

11 Q If I can get you to turn to page 10 of your
12 testimony. You identify some demand-related costs, and I'm
13 just curious, at what time of the day and year is the
14 company concerned with customer -- with residential customer
15 peak load?

16 A (Witness Legg) You said page 10 of our
17 rebuttal testimony?

18 Q Yes.

19 A (Witness Legg) And which line specifically?

20 Q In the first paragraph, lines 1 through 4. It
21 may start on page 9. And I'm just curious at what time of
22 the day and year is the company concerned with residential
23 customer peak load?

24 A (Witness Legg) When you say "concerned with
25 residential customer peak load" --

1 Q Or ones to address residential customer peak
2 load. Is it system peak load? Class peak? What --

3 A (Witness Legg) Yeah. The company is --
4 certainly is concerned with making sure it can serve its
5 customers in all hours of the year. Different peaks occur
6 at different times. Generally, in the summertime, it's, you
7 know, weekday afternoons when there's hot weather. In the
8 wintertime, it could be on a cold winter morning, maybe in
9 January or February, December. But certainly, we're
10 concerned about serving our load during all hours.

11 Q Okay. And has the company conducted a study to
12 identify when residential customers typically have their
13 peak as defined by this rate, TOU-RD?

14 A (Witness Legg) I don't believe we have
15 specifically for TOU-RD. Certainly, our forecast process
16 identifies when the company peaks by class and as a whole.

17 Q And has -- can the company -- has it looked at
18 or studied if customers on this TOU-RD rate have lowered
19 their peak demand after receiving price signals on this
20 rate?

21 A (Witness Legg) Are you talking about the
22 time-of-use energy price signals?

23 Q Um-hum.

24 A (Witness Legg) We haven't studied that
25 recently. The TOU-RD rate has actually been around since, I

1 believe 2013, and early on, there were studies of that that
2 did show peak demand reduction, showed energy being shifted
3 outside the TOU rate, but it's been a number of years since
4 we've done that.

5 Q And so, I think, back to Commissioner Echols'
6 point, how do we know this rate is effective in achieving
7 the desired outcome from customers?

8 A (Witness Legg) Well, when you say, "the
9 desired outcome," the desired outcome for the company is,
10 you know, is several-fold. One is to obviously collect the
11 revenues for the costs that are being -- cost to serve our
12 customers. That's the purpose of, you know -- the first
13 purpose of all rates is to make sure the company can recover
14 its costs.

15 The next would be, in a case of a time-of-use
16 rate, to be able to send effective price signals.
17 Generally, from a rate design standpoint, we talked about
18 the time-of-use price signal on this rate. You would want
19 the time -- the on-peak, the differential between the
20 on-peak and off-peak to be at least two or three times
21 higher, so the on-peak price at least two or three times
22 higher than the off-peak price. On this rate, it is
23 actually about nine times higher, so we consider that a
24 significant price signal in the on-peak period.

25 The other -- and so from that standpoint, we

1 believe that the tariff itself sends effective price signals
2 and does a good job of collecting revenue.

3 Q So you don't have a specific study that shows
4 it lowers demand?

5 A (Witness Legg) Not one that we've done in this
6 rate case cycle, no.

7 Q Okay. Looking at Figure 2 on page 10 of your
8 rebuttal testimony.

9 A (Witness Legg) Yes.

10 Q It compares a sampling of customers that are on
11 various residential rates. Am I correct in my understanding
12 of that?

13 A (Witness Legg) Yes. It's comparing the
14 difference between the minimum and maximum bill for the year
15 on those different rates. So it's getting at bill
16 stability.

17 Q Okay. And am I correct that it doesn't show a
18 comparison of what a bill for a single customer on various
19 rates would look like?

20 A (Witness Legg) Actually, you could call this a
21 single customer. This is the average residential customer
22 compared on all three rates. So we just took the average
23 customer profile for the residential class, ran it through
24 all three rates, and these are the results from a stability
25 standpoint.

1 And what it is showing is, as you can see, the
2 difference between the highest bill and lowest bill for the
3 year for the R rate is about 115 percent. So 202 is about
4 115 percent higher than \$94. And then for TOU residential
5 energy only, it's about 134 percent. For the TOU-RD rate,
6 as we've said in the past, it has a more stable billing
7 profile. The difference between the highest and lowest
8 bills is about 61 percent. So you could technically say it
9 is for one customer, the average customer.

10 Q Okay. And regarding the current and proposed
11 declining block rate that exists on the R rate during
12 non-summer months, in your testimony on page 6, you state
13 that it recognizes that off-peak costs are generally lower,
14 and, therefore, provides price signals to reflect this
15 reality.

16 But if the declining block rate was replaced
17 with a flat rate, wouldn't this rate still be lower than the
18 summer inclining block rates, therefore, still reflecting
19 the same price signal?

20 A (Witness Legg) Yes. It would still be lower
21 in some hours. Now, the way that the rate is designed right
22 now, for the first 650-kilowatt hours in the summer or
23 non-summer months, the price is the same. In the summer,
24 the more you use, the higher it goes, the price goes. In
25 the winter, the lower it goes the more you use.

1 So if we were to actually turn the winter price
2 into one price, that would probably bump it up higher for
3 the first 650-kilowatt hours. So actually, customers who
4 use less energy could be adversely impacted by that. To
5 collect the same amount of revenue over those non-summer
6 months, you would have to bump the price up because you are
7 taking away the lower prices.

8 Q The justification for the declining block rate
9 follows from a statement just above on page 6, line 12,
10 stating that inclining price structure during summer months
11 provides incentives for energy efficiency and conservation.

12 So by extension, does the declining price
13 structure provide a disincentive for energy and efficiency
14 and conservation during summer months?

15 A (Witness Legg) And I am sorry. I was -- while
16 you were asking that, I was thinking about what I just said.
17 I may have had it backwards. Since it declines in the
18 wintertime, you may have to actually lower the price a
19 little bit in the wintertime. I would have to think through
20 that.

21 There wasn't an analysis presented, so I don't
22 have the exact numbers from staff's recommendation. But I
23 believe, actually, since it declines, you may have to
24 actually lower the price a little bit. But we would have to
25 analyze that. Anyway it would be different. The first 650

1 block would be different.

2 So, I'm sorry, what was your question again on
3 page 6?

4 Q Okay. So page 6, line 12, you say that the
5 inclining price structure during summer months provides
6 incentives for energy efficiency and conservation. So by
7 extension, does that mean that the declining price structure
8 provides a disincentive for those same things?

9 A (Witness Legg) No, I wouldn't say it provides
10 a disincentive. And I want to make sure this is all in
11 context. If you look up at lines 8 and 9, I start this
12 section out by saying: Although the price signal the R rate
13 sends is not as strong as more recent tariff designs.

14 So we are talking about price signals. I think
15 we talked about this a little bit in the -- in the direct
16 hearings, the magnitude in change from the summer inclining
17 is much, much larger than the decrease in the winter. The
18 summer prices go from -- I'm ballparking numbers here --
19 maybe five and-a-half cents for your first 650-kilowatt
20 hours up to like nine and-a-half or 10 cents for above that.
21 So it's a significant jump. Whereas the declining block in
22 the wintertime goes from the same five-and-a-half or so,
23 down to maybe five or four-and-a-half, so it's a much
24 smaller decline than the incline is in the summer.

25 So -- and I would say, again, the R -- the R

1 rate does send that price signal that, if you use a lot
2 more, it's going to get much more expensive in the
3 summertime. We don't feel that that's, you know -- that's
4 an outdated design. That's part of why we would like to get
5 away from this. It's not the best way to send a price
6 signal. As we were talking earlier, time-of-use periods are
7 better.

8 Certainly, in the signal sent in the declining
9 winter period, is that there is generally capacity available
10 during the wintertime, and that it's cheaper, and so -- so
11 there's, you know, cheaper energy to be used. For instance,
12 if you decided to put electric heating in or something like
13 that.

14 Q On page 6, line 17 of your rebuttal testimony,
15 you say that: This increase in customer usage in the
16 non-summer months reduces rates, but when a customer
17 increases their usage, they increase their bill. Even if
18 the rate they pay per kilowatt hour declines, the bill is
19 going to increase with usage; right?

20 A (Witness Legg) I'm sorry. I may have missed
21 that reference. Which line were you referring to?

22 Q I believe line 17.

23 A (Witness Legg) On page 6? Mine says the
24 prices are set to more than cover the company's marginal
25 costs. Resulting revenues place downward pressure on rates.

1 Q Right. And my question is, regardless of the
2 structure, when a customer increases their usage, they
3 increase their bill, so even if the rate they pay per
4 kilowatt hour declines, their bill is going to increase with
5 usage, sending a signal; right?

6 A (Witness Legg) I don't know if I would call
7 that sending a signal. I mean, certainly if they increase
8 their usage, the additional usage isn't free, so their bill
9 will go up. It's cheaper. You could look at it as a volume
10 discount, if you will, maybe is a good way to compare it on
11 the retail. You know, the more you use, the cheaper it is.

12 I wouldn't call that a signal just because
13 their bill is going up for using more. I think the signal
14 is -- the price is going down, so it's cheaper to use on a
15 per-unit basis.

16 Q That's all the questions I have. Thank you.

17 MADAM CHAIR PRIDEMORE: Americans for
18 Affordable Clean Energy?

19 MR. GALLOWAY: Madam Chair, as we did with the
20 panel this morning, I want to distribute all of our
21 documents that I'll be using --

22 MADAM CHAIR PRIDEMORE: That's what I have
23 asked everybody to do. That's fine.

24 MR. GALLOWAY: These are already admitted into
25 evidence, but it will help the witnesses to have.

1 MADAM CHAIR PRIDEMORE: Thank you. Maybe
2 Mr. Thomas can help you get them out there. Or not.

3 CROSS-EXAMINATION

4 BY MR. GALLOWAY:

5 Q Good afternoon, panel. Newton Galloway on
6 behalf of AACE.

7 Mr. Evans, as with the first round, I don't
8 have any questions for you.

9 Mr. Legg, I want to pick up, and I want to talk
10 about the CIEV rider and tariff that you discuss at page 17
11 of your rebuttal testimony.

12 And first of all, were y'all here for the
13 presentation and testimony from the Abramovitz panel this
14 morning into the afternoon?

15 A (Witness Legg) I was not here. I was able to
16 watch a little bit of it online.

17 Q Okay. I asked them a series of questions about
18 community chargers. I want to confirm, Mr. Legg, that
19 community chargers will not pay a tariffed rate for the
20 electricity that is used to charge EV's from a community
21 charger?

22 A (Witness Legg) Georgia Power's community
23 chargers? That's right. They -- they don't.

24 Q That's correct?

25 A (Witness Legg) Yes.

1 Q And that electricity will be accounted for on
2 the basis of however Georgia Power accounts for its own
3 internal electric use?

4 A (Witness Legg) That's right.

5 Q All right. Now, I've distributed to you three
6 documents. All of these are already in evidence. The first
7 is the proposed PLM-14 tariff. And that is important to EV
8 charging because that is the basis for the charges that
9 will -- the charge -- the tariff rates that will be charged
10 to the EV charging provider; correct?

11 A (Witness Legg) It's possible. Actually, the
12 charge-it rider as proposed would modify the -- either the
13 power and light small, power and light medium, or power and
14 light large, so...

15 Q I'm using PLM as an example.

16 A (Witness Legg) Yes.

17 Q And that would be adjusted by the CIEV rider;
18 correct?

19 A (Witness Legg) Yes.

20 Q All right. And that's identified as AACE
21 Exhibits 11 for PLM-14 and 10 for the CIEV rider. And like
22 I say, I want to use the PLM-14 as an example.

23 Now, let's walk through this for just a little
24 as we flesh out, in these final minutes of the rate case.
25 Let's flesh out a little bit on how the tariff --

1 MADAM CHAIR PRIDEMORE: We could only be so
2 lucky, Mr. Galloway. Perhaps if you were a little
3 quicker with your questions, you might get us to
4 that.

5 MR. GALLOWAY: I am moving. I am moving.

6 MADAM CHAIR PRIDEMORE: I would like you to
7 move a little quicker. Thank you.

8 BY MR. GALLOWAY:

9 Q The CIEV rider will apply only to a new metered
10 location; correct?

11 A (Witness Legg) That's right.

12 Q And under PLM, PLM has a basic tariff charge,
13 basic charge of \$136; correct?

14 A (Witness Legg) Yes.

15 Q It has an energy charge which includes a demand
16 charge that's based upon hours of consumption; correct?

17 A (Witness Legg) Right. It's an hours-use
18 demand rate, so you look at your hours-use demand, which is
19 effectively your energy use relative to your peak demand,
20 and that shows you which of the pricing buckets that your
21 energy falls into.

22 Q And this also includes -- under PLM, it
23 includes a billing demand charge, correct, of \$8.78 per
24 kilowatt of billing demand in excess of 30 kilowatts;
25 correct?

1 A (Witness Legg) Only if the minimum bill
2 component kicks in.

3 You're reading from the minimum monthly bill
4 section?

5 Q Correct.

6 A (Witness Legg) Yeah. That's only if, in
7 calculating your bill through the regular rate, the -- you
8 don't pass the minimum threshold to cover the costs that are
9 required in this tariff. So that's only if the -- if you
10 don't -- if your bill is not high enough, basically, to pay
11 the -- just the cost to -- for service there.

12 Q And to determine the calculation of the billing
13 demand, you have to look at page 2, correct, of the tariff,
14 of the PLM-14 tariff?

15 A (Witness Legg) That's right.

16 Q Okay. Can you define what the billing demand
17 is?

18 A (Witness Legg) The billing demand in this case
19 is the number that's used to determine, again, how your
20 energy flows through the prices that are on page 1. Again,
21 you're charged on this rate based on how much energy you use
22 relative to the peak demand that you set for the month.
23 It's a standard rate design for electric utilities for
24 commercial and industrial use called hours use demand. And
25 so the billing demand is part of that calculation to

1 determine your hours use demand that then is used to flow
2 you through those price buckets.

3 Q And the billing demand is based upon the
4 highest 30-minute kilowatt measurement during the current
5 month or the pre -- and the preceding 11 months; correct?

6 A (Witness Legg) There are different
7 requirements for summer months versus non-summer months in
8 the calculation of the billing demand, and that's all laid
9 out on page 2, yes.

10 Q But it's based upon that peak 30-minute
11 interval; correct?

12 A (Witness Legg) Yes. And there is a ratchet
13 effect that could affect the next 12 months, the next --

14 Q Okay.

15 A (Witness Legg) Yes, next 12 months.

16 Q If a charger has abnormally high charging use
17 for 30 minutes, that will become the billing demand, will it
18 not?

19 A (Witness Legg) It could become the billing
20 demand. It just depends. Again, in the non-summer months,
21 the billing demand can be the greatest of 95 percent of the
22 highest summer month or 60 percent of the highest winter
23 month. So -- as outlined here.

24 Q PLM does not take into account peak or off-peak
25 demand times; correct?

1 A (Witness Legg) Do you mean from an energy
2 standpoint?

3 Q Yes, sir.

4 A (Witness Legg) It is not a time-of-use rate,
5 if that's what you mean. We don't charge different energy
6 prices for different times of the day.

7 Q So as applied to an EV charger, this would be
8 different from the residential EV tariffs which do have
9 time-of-use differentials and rates based upon peak and
10 off-peak?

11 A (Witness Legg) That's right.

12 Q Okay. So there are, as I understand it, three
13 components of the charger bill under the tariff. The first
14 would be a basic service charge; correct?

15 A (Witness Legg) I am sorry. Three parts of?

16 Q The three components -- as I am reading the
17 tariff, there are three components of the tariff charge.
18 The first would be a basic service charge?

19 A (Witness Legg) Right.

20 Q The second -- and that's in the PLM tariff?

21 A (Witness Legg) Yes. Well, in all tariffs,
22 there's a basic service charge.

23 Q Well, I'm with you on that. But you -- and
24 let's, just a PLM, you would have the basic service charge.
25 There would be an energy charge; correct?

1 A (Witness Legg) Right.

2 Q And then there would a demand charge?

3 A (Witness Legg) No. Only if the minimum bill

4 component kicks in. Only if your bill is not high enough to

5 avoid the minimum bill calculation. The only reason the

6 billing demand is used or there is a demand charge is to

7 calculate your hours use of demand to see how your energy

8 falls within these pricing buckets.

9 Q But if it kicks in, then you've got a demand

10 charge --

11 A (Witness Legg) For the minimum bill instead of

12 the other energy charges.

13 Q All right.

14 A (Witness Legg) So to be clear, you never have

15 all three. It would either be the bill is calculated with

16 all the energy charges, or it would just be the minimum bill

17 calculation in lieu of that.

18 Q And all of those are found in the PLM-14 or, if

19 it's approved, the PLM tariff; correct?

20 A (Witness Legg) Yes.

21 Q And then the adjustment to the demand charge is

22 found in CIEV; correct?

23 A (Witness Legg) That's right. The tariff is

24 designed, the CIEV rider is designed to adjust those billing

25 demands down during the four-year period that the -- the

1 first four years that the customer is on the CIEV rider by
2 either 80 percent, 60 percent, 40 percent, or 20 percent.

3 So it's an adjustment to the billing demand
4 that then plays into -- into the calculation of the bill,
5 which effectively would have the -- would result in the
6 customer paying the lower bill, you know, gradually over
7 time that comes back to the normal tariff. And, again,
8 that's to incentivize new charger installations during the
9 ramp-in period while the market is maturing and there may
10 not be as much use in the early years.

11 Q Now, the CIEV rider expires after four years;
12 correct?

13 A (Witness Legg) For each individual customer,
14 yes. We're not proposing that the rider itself go away,
15 but, yes. Once a customer signs up, they would stay on the
16 rider for four years, unless their load factor reached a
17 point such that it wouldn't be effective anymore. Once they
18 reach a 15-percent load factor and they're in the lower
19 buckets of these energy charges, then really the point
20 becomes moot, because they have more -- more usage.

21 Q Now, these -- the CIEV applies to new service
22 with a new meter; correct?

23 A (Witness Legg) Right. Separately metered EV
24 charging, yes.

25 Q So how do we do a calculation -- so the

1 Commission will understand. How do we do a calculation of
2 the demand charge for a new metered service for which there
3 is no history to give and to state a peak demand?

4 A (Witness Legg) Well, the peak demand -- the
5 demand would be measured each month, the first month that
6 the customer had service there, then we would -- just like
7 we would measure their energy use, we would measure their
8 demand -- their peak demand as well, and that's what would
9 go into the billing calculation.

10 Q So if you did have a higher peak the first
11 month, that would carry forward?

12 A (Witness Legg) It could. Again, it depends on
13 which month it is, if it's a summer or non-summer month.
14 And that's true for all commercial and industrial rates on
15 the power and light -- I mean, customers on the power and
16 light rates. I mean, this is a standard rate design.

17 All we're proposing with charge-it is to,
18 again, give a reduction to that billing demand to allow them
19 to pay lower prices just during the first four-year period
20 while the market is maturing.

21 Q So let's follow up with what you just said.
22 The PLM, PL, whether it's small, medium, or large, PLM is
23 a -- one of the core business tariff rates that Georgia
24 Power uses to charge electricity to commercial customers?

25 A (Witness Legg) It's a standard rate design in

1 the industry. Hours use demand rate. It's effective at
2 recovering costs based on how they're caused, because it
3 takes into account both the customer's energy use and their
4 demand use and how much infrastructure the company has to
5 build to serve their energy needs.

6 Q So after the four-year period when CIEV would
7 be applicable, then the charger is effectively on a standard
8 commercial rate; correct?

9 A (Witness Legg) That's right. And the thought
10 there would be, over a four-year period, in theory, the
11 market will mature. We'll have another chance to look at
12 this three years from now in the next rate case and see what
13 has happened with EV charging, see how these customers are
14 performing, see how the market has matured or not matured,
15 and then make a decision at that point.

16 But certainly that's the idea is that, if the
17 market matures over the next few years, there really won't
18 be a need for this because there will be a lot more
19 charging, the people who own the EV chargers will have a lot
20 more customers, and so forth. So their bill will come down
21 just by virtue of the fact that they have a lot more usage.

22 Q Okay. This morning the Abramovitz panel
23 testified that the company maintains data on the usage of
24 virtually all of the electric chargers that are out in the
25 field, both the ones they own and the ones that have been

1 employed by others.

2 Are you familiar with that?

3 A (Witness Legg) Certainly, we have data for our
4 chargers, and then to the extent that anything in the field
5 is a customer of Georgia Power, we would have their meter
6 data, because we bill those customers, yes.

7 Q Did the company, in preparation for CIEV, look
8 at usage trends for EV's at existing chargers to determine
9 whether this tariff structure is appropriate for EV
10 charging?

11 A (Witness Legg) Yes, that is one of the things
12 that we took into account.

13 Q Okay. Did you review the testimony of
14 Mr. Nelson tendered on behalf of AACE back in the intervenor
15 portion?

16 A (Witness Legg) Yes.

17 Q Okay. Did you have a chance to look at
18 Exhibit 6, which is in your materials, and was tendered as
19 AACE Exhibit No. 20?

20 A (Witness Legg) I had a chance to look at it.
21 There were a lot of exhibits. I don't know that I could
22 immediately say exactly what the analysis is showing.

23 Q Well, this was an example assuming a monthly
24 usage of a charger of roughly 3,200 kilowatt hours. And it
25 was looking at the cost that would be incurred by the

1 charger under the CIEV and PLM tariffs at that level of
2 charging; correct?

3 A (Witness Legg) Yes, looks like it.

4 Q Okay. And the calculations assume some growth
5 over time, but in the first year, it would have resulted in
6 a -- if you look at the third column of the PLM-14 with CIEV
7 rider, it would have resulted in annual charges of
8 approximately \$6,300?

9 A (Witness Legg) That's what it says.

10 Q And with the other riders attached to it, it
11 would result in charges, annual charges of roughly \$7,900?

12 A (Witness Legg) That's what it says, yes.

13 Q Okay. Assuming the accuracy of those, based
14 upon that level of service, that would mean that the
15 charge -- excuse me -- the monthly charge under PLM-14
16 without the other riders would be approximately \$526 per
17 month?

18 A (Witness Legg) Are you just dividing the
19 6,317 --

20 Q Divided by 12. Yes, sir.

21 A (Witness Legg) I'll accept that subject to
22 check. I haven't done the math.

23 Q And doing the same math, understanding you
24 haven't done it yet, but the cost with the other riders
25 attached would come out to about \$658 per month?

1 A (Witness Legg) Subject to check, sure.

2 Q All right. Now, that would not obviously
3 include other equipment costs. And it is -- it is well
4 possible that the tariffed rate could exceed the revenue of
5 the charger, at least at this point in the state of
6 development of EV charging, is it not?

7 A (Witness Legg) Certainly, it's possible. It
8 shows in that first year a load factor of 2.43 percent,
9 which is, of course, very low. That means that you're
10 not -- not using much energy relative to the demand that's
11 being set. And really, when we're talking about the demand
12 that's being set, I think it's an important concept, the
13 company has to place transformation and equipment out there
14 to be able to serve the peak demand.

15 So if the -- if the demand is going to, let's
16 say, for a level three charger with a couple of locations,
17 might be several hundred kW, the company has to set
18 equipment out there to be able to meet that peak demand need
19 when those chargers are in use.

20 So that's, you know, if you -- if the company
21 invests a lot in equipment to serve a load, but then not
22 much energy is sold, that's -- that's why, again, the power
23 and light medium tariff and other tariffs that we talked
24 about are priced based on load factor, because the company
25 has to recover those costs to serve that location if not

1 much energy is used but a lot of investment has been made on
2 the company's behalf.

3 Q All right. And --

4 A (Witness Legg) And that's really what we're
5 talking is about just trying to recover the investment for
6 the company.

7 Q Well, let's talk about an independent company
8 that would be looking to recover investment. If the costs
9 in the tariff approach or exceed the revenues, then it's
10 going to have to decide, make critical decisions on where it
11 will deploy EV chargers if it chooses to be in that
12 business; correct?

13 A (Witness Legg) When you say, "the revenues,"
14 you mean the revenues that company would get from charging
15 services?

16 Q Yes, sir.

17 A (Witness Legg) Certainly, that's a standard
18 business decision looking at the costs and the revenues,
19 yes.

20 Q One decision it could make would be to deploy
21 chargers only in higher volume areas?

22 A (Witness Legg) Certainly.

23 Q And the other -- another choice that could be
24 made would be to increase costs of the charging provided at
25 the charger?

1 A (Witness Legg) The price that they charge
2 their customers?

3 Q Price, yes, correct.

4 A (Witness Legg) Yes.

5 Q All right. I said "costs," but you got me
6 right.

7 Are you familiar with the Alabama tariff which
8 is in the materials and identified as AACE Exhibit No. 12?

9 A (Witness Legg) I am generally familiar with
10 it, yes.

11 Q Okay. And that tariff provides for a
12 standard -- in my view, it is a very simple tariff which
13 includes a base charge and a simple charge per kilowatt hour
14 with seasonal adjustments; correct?

15 A (Witness Legg) Yes. A base charge, and it
16 looks like it has different energy charges for June through
17 September and then for October through May.

18 Q That's what I was saying, seasonal
19 adjustments --

20 A (Witness Legg) Yes.

21 Q -- it makes very -- it changes the rate to some
22 degree?

23 A (Witness Legg) And within that, it's got
24 on-peak, intermediate peak, and off-peak within it.
25 Seasonal.

1 Q It's one tariff. You don't have to go back and
2 forth between two tariffs; correct?

3 A (Witness Legg) I assume so. I don't know if
4 Alabama Power has anything that modifies this or not.

5 Q If they do -- if they do, we can't find it.

6 You don't have to calculate a demand charge
7 because it is calculated in the tariff, is it not? It's set
8 out in the tariff?

9 A (Witness Legg) I don't know. I'm not an
10 expert on Alabama Power's rates or rate structure. I would
11 note the effective date of this is January 2006.

12 Q It's been around a while.

13 A (Witness Legg) So I would not imagine that
14 this was specifically designed originally for, like, DC fast
15 chargers or anything like that, because they've only been
16 around for the last few years.

17 Q Well, let me --

18 A (Witness Legg) But it does say business
19 electric vehicle time of use.

20 Q Let me conclude by asking you a final question.
21 Would it not be better policy to do a simple tariff now,
22 until we can establish a track record of usage of EV
23 chargers to determine whether a demand charge based on that
24 data is appropriate?

25 A (Witness Legg) I'm sorry. Could you ask that

1 again?

2 Q Wouldn't it be better policy at this juncture
3 in the development of EV charging to do a simple tariff,
4 something along the lines of Alabama's, establish a track
5 record of usage for EV chargers, to determine whether a
6 demand charge is appropriate in this context?

7 A (Witness Legg) No, I don't necessarily agree
8 with that. I think what we're talking about is putting a
9 charging rate out there that makes sure that, over the life
10 of a charger, we're recovering the costs, while at the same
11 time making adjustments in the early years to try to help
12 those -- those chargers be cost effective until the market
13 matures. That's what we're aiming at with the charge-it
14 electric vehicle rider on top of the power and light rates.

15 I would be concerned -- and by the way, I
16 should say, this is -- you mentioned this is an Alabama
17 Power rate. It's time-of-use; it's seasonal. Georgia Power
18 has commercial time-of-use rates as well. Just like the
19 power and light medium rate is available for customers
20 between 30 and 500 kW, we also have time-of-use business
21 rates that are available for those customers, too.

22 So it's not that we don't have a simpler rate
23 that's time-of-use based. It's that we're trying to target
24 specifically these customers in the early years of EV
25 charging installations.

1 The concern I would have if we put a rate out
2 there that was simple that didn't account for the fact that
3 there could be high demands with low energy use is that, if
4 there's not a rate in place for the company to eventually
5 recover its cost to serve that type of location, someone
6 else has to pay for that equipment.

7 And so, eventually, that would be a cost that
8 is shifted over to other customers if the simpler rate
9 didn't do a good job of recovering the investment that was
10 put out there and then not many -- not many cars use the
11 charger. So that's -- that would be a great concern.

12 Q Would you -- I said that was the final
13 question. I was close.

14 If the tariff is set, and the tariff ultimately
15 results in costs of the tariff not being covered by the
16 revenues generated from charging, you would agree that that
17 results in the deterrence of the deployment of chargers?

18 A (Witness Legg) Are you talking about the
19 company's cost not being recovered?

20 Q No, no, no. I'm talking about an independent
21 company. Because y'all aren't paying the tariff. What I'm
22 saying is, if the tariff is set to where initially in the
23 beginning the revenues from charging can't cover the tariff
24 costs, then that deters the incentive to deploy the charger?

25 A (Witness Legg) That would be a question for

1 the EV charging companies. What I do know, and as I've said
2 here in testimony before, I drive an electric vehicle. I've
3 had a Leaf for about eight years, so I've used a lot of
4 public charging. What I do know is, we are obviously trying
5 to incentivize additional EV charging out there. As the
6 market grows, as more people adopt electric vehicles, that's
7 a choice customers have. If a lot more of them adopt those,
8 we want to make sure there's charging infrastructure in
9 place to be able to serve them.

10 But I would also say, at the same time, we have
11 to make sure that we recover those costs. And there are
12 several thousand chargers out there. We know we will need
13 more, but there are already a few thousand chargers out
14 there in the state of Georgia. So someone has made the
15 decision to make those investments to this point. You know,
16 it's their individual business plan, I guess, to determine
17 whether or not they're making money, the appropriate amount
18 of money. But that would have to be a choice for each of
19 those companies looking to make that investment.

20 Q But, Mr. Legg, the existing chargers are not on
21 a CIEV rider attached to a PLM tariff?

22 A (Witness Legg) That's right.

23 Q No further questions. Thank you.

24 MADAM CHAIR PRIDEMORE: ChargePoint?

25 MR. DUNBAR: No questions.

1 CHAIRWOMAN PRIDEMORE: Commercial Group?

2 MR. JENKINS: No questions.

3 CHAIRWOMAN PRIDEMORE: Georgia Association of
4 Manufacturers?

5 MR. CHARLES JONES: Yes, ma'am. Very briefly.
6 Thank you, Madam Chair.

7 CROSS-EXAMINATION

8 BY MR. CHARLES JONES:

9 Q Good afternoon, panel.

10 A (Witness Legg) Good afternoon.

11 A (Witness Evans) Good afternoon.

12 Q The company claims its generation planning is
13 driven by non-summer periods in addition to the summer
14 peaks.

15 Is that a part of your testimony?

16 A (Witness Evans) Yes.

17 Q Do you agree with that?

18 And capacity needs are driven heavily by winter
19 needs, and so production cost allocations should recognize
20 that. Is that the company's position?

21 A (Witness Evans) Yes, that our generation
22 planning requires service around -- year round for all 12
23 months and that generation allocation should reflect that.

24 Q Notwithstanding that, Georgia Power is still
25 projected to be a strongly summer peaking utility.

1 Would you agree with that?

2 A (Witness Evans) On a weather-normal basis,
3 yes.

4 Q Okay. I noticed in your testimony you did not
5 address the -- I'll call it the 6 CP proposal that
6 Mr. Pollock made to look at four summer peaks and two winter
7 peaks. Did you analyze that proposal by Mr. Pollock, in
8 terms of whether that would be an effective or useful
9 cost-of-service study to look at?

10 A (Witness Evans) Yes, we looked at it. Similar
11 to his previous testimony, I believe it -- the last case it
12 was 5 CP that we had looked at then, too. We continue to
13 believe that 12 CP is the most reflective cost allocation
14 for Georgia Power production assets.

15 In addition to it being long-filed and approved
16 by this Commission, it also is strongly preferred by FERC.
17 FERC actually issues a series of tests that they look at to
18 deem the reasonableness of a 12 CP allocation. We performed
19 those tests, and it indicates through those FERC tests that
20 12 CP is also the most strong allocation method of Georgia
21 Power loads.

22 Q Okay. Now, the company does not oppose parity
23 adjustments in general, but you do oppose parity adjustments
24 that were proposed by other parties in this case; is that
25 correct?

1 A (Witness Evans) I think it was -- in our
2 testimony, we talk about using the cost-of-service study
3 that we filed that shows the appropriate 12 CP allocation
4 and the resulting parity adjustments from that.

5 Q And you propose that, instead, that parity
6 should be measured according to eight rate groups rather
7 than individual rates; right?

8 A (Witness Evans) That is correct, yes.

9 Q And you made that point in response to, not
10 only the staff-proposed parity adjustments, but GAMs as
11 well. Would you agree?

12 A (Witness Evans) Yes. And that's been the
13 company's recommendation ever since the rate groups were
14 introduced. Going back to 2004 testimony, and then
15 reestablished in '7, in '10, in '13, and '19, we have always
16 been on the record suggesting and advocating that the
17 adjustments to parity by rate group were most appropriate.

18 Q But isn't it true that Mr. Pollock proposed
19 parity adjustments in his testimony that are actually
20 measured according to the eight rate groups as opposed to
21 individual tariffs? I have a copy of his testimony if you
22 would like to --

23 A (Witness Evans) Sure.

24 MR. CHARLES JONES: May I approach the witness?

25 MADAM CHAIR PRIDEMORE: You may approach.

1 BY MR. CHARLES JONES:

2 Q So I'm showing you, that's Mr. Pollock's
3 testimony on page 34. Do you see his table there? I
4 believe it's Table 7.

5 A (Witness Evans) That's correct. Yes.

6 Q Okay. So can we be in agreement that
7 Mr. Pollock shares your approach of measuring it by rate
8 groups instead of --

9 A (Witness Evans) Yes. And I believe in our
10 testimony, when we talked about Mr. Pollock's testimony, it
11 was not using his cost-of-service study results. Not
12 necessarily that we opposed the grouping by -- or the parity
13 adjustments by rate group at all.

14 Q Okay.

15 MR. CHARLES JONES: Madam Chair, that's all I
16 have. Thank you.

17 MADAM CHAIR PRIDEMORE: Georgia Coalition of
18 Local Governments?

19 CROSS-EXAMINATION

20 BY MS. BROWN:

21 Q Good afternoon, panel.

22 A (Witness Evans) Good afternoon.

23 A (Witness Legg) Good afternoon.

24 Q If I can direct you to the section of your
25 testimony on community solar in pages 14 through 18.

1 A (Witness Evans) Okay.

2 Q To start with, these questions are going to be
3 more general in nature. So the first question I have is, is
4 it accurate to say that the subscription price for the
5 community solar program is set to be roughly equal to what
6 customers would have paid if they weren't enrolled in the
7 program?

8 A (Witness Legg) Generally, it's set to be -- to
9 avoid, yeah, any shifting of cost to nonparticipants, so
10 it's -- so it is -- you know, it's not going to be on a
11 per-customer basis exactly, but it would be roughly, yes,
12 for the whole group of customers, to make sure there is no
13 cost shifting.

14 Q Okay. So in doing that analysis, that includes
15 base rates, fuel, ECCR, NCCR, franchise fee, all of those
16 components?

17 A (Witness Legg) That's right.

18 Q So to be clear, the subscription price includes
19 riders like -- like fuel. That's actually factored into the
20 price?

21 A (Witness Legg) It's factored into the charge
22 to make sure that the program is not shifting cost. And the
23 reason is, when a customer participates in community solar,
24 we actually subtract the output of the community solar
25 facilities from their energy use before we calculate their

1 bills. So even though they are using fuel, they're using --
2 you know, they have cost responsibilities for all those
3 different components, it's being backed out in their bill.
4 So it has to be added back in, or else someone else would
5 have to cover that cost.

6 Q And that calculation is based on a certain
7 amount of production for the three solar arrays that are
8 involved; is that correct?

9 A (Witness Legg) I think it's based on the
10 actual production in a given month, yes.

11 Q When setting the price, I mean, for this rate
12 case, is that looking at --

13 A (Witness Legg) Assumptions, yes.

14 Q Okay.

15 A (Witness Legg) Sure.

16 Q Okay. So if production is less than expected
17 for a month or a series of months, the customer still pays
18 the same subscription price?

19 A (Witness Legg) Yes. And if it's more than
20 expected, they would pay the same subscription price as
21 well.

22 Q All right. So if we've established that fuel,
23 the ECCR, NCCR, are in the subscription price or used to
24 calculate the subscription price, is it possible that, if
25 the solar arrays underperform based on the assumption that

1 went into the calculation, that a customer would pay in the
2 subscription price and then again at the meter?

3 A (Witness Legg) It's possible that they would.
4 I guess the converse is true as well. If it overperforms,
5 then they would be paying less than they had actually used
6 at the meter as well.

7 So certainly, with any price that's set based
8 on assumptions, the only thing we know about a forecast of
9 assumptions is it's wrong. We don't know if it's too high
10 or too low; we just know that it's going to be something
11 different than what, but it's based on the best available
12 information we have at the time.

13 Q But looking specifically at page 16 where the
14 coalition was referred to as "misguided," are you saying
15 that there are some situations in which a customer can pay
16 twice?

17 A (Witness Legg) Which line are you referring
18 to?

19 Q That was 19.

20 A (Witness Legg) Right. The -- the -- it says,
21 "In addition, the coalition bases their reduction on the
22 misguided premise that community solar participants pay for
23 rate riders like NCCR, ECCR, and fuel more than once."

24 Again, like we just said, it's -- the fee is
25 set to -- at a high level, at an average level across all of

1 the participants to make sure that there's no cost shifting.
2 Certainly, there could be a little over in some months, a
3 little under in some months, but generally, it's a match.
4 Is the forecast for that.

5 Q Okay.

6 A (Witness Legg) You're not going to hit every
7 customer exactly right on the nose.

8 Q All right. If we can move to hourly usage
9 data. Specifically, the first question on page 20.

10 A (Witness Legg) Yes.

11 Q So the company asserts that only a limited
12 number of customers are unable to view their hourly usage in
13 My Power Usage, which I believe is AMI opt-outs, unmetered
14 accounts, and then some of the more complicated rates like
15 RTP.

16 Are these the only situations in which a
17 customer cannot access their data through My Power Usage?

18 A (Witness Legg) There may be a few others.
19 When we say -- obviously, those who opt out of an AMI meter,
20 since the My Power Usage tool is fed from the AMI system, if
21 they don't have an AMI meter, then we don't have the data
22 available for the hourly usage there.

23 The customers -- we talk about special service
24 account and RTP customers. Special service accounts are a
25 separate set of groups that are very large commercial

1 industrial rate -- customers built on complex rates.

2 RTP customers, in particular, have hourly usage
3 that we have to have recording meters on because they
4 actually pay a different price every hour out of the year
5 for part of their use. So they have much more complex
6 metering. That system is separate, and it has been separate
7 for a number of years before we developed the AMI system, so
8 it doesn't feed into the AMI system.

9 So there's hourly data available for those
10 customers; it's just not through My Power Usage. And it's
11 actually part of a package in a website called Energy
12 Direct.com that has been around, again, probably 20 years or
13 more, providing hourly usage to those customers, but they
14 pay a subscription fee because it's not just providing those
15 hourly usage numbers, it's providing a number of other tools
16 that they can use to analyze usage, calculate bill
17 estimates, things like that.

18 Q So what would your response be if I told you
19 that each of the member governments in the coalition has
20 accounts that are not AMI opt-outs. They're not unmetered.
21 They're not RTP. And still can't access that data. What
22 would your response be?

23 A (Witness Legg) That's possible. I don't run
24 that AMI system, but my understanding is generally, again
25 out of 2.7 million customers, almost all of them are run

1 through AMI.

2 Q Okay.

3 A (Witness Legg) And we'd be glad to talk to you
4 about that if that's the case.

5 Q Yeah, that would be wonderful.

6 Looking at page 19, lines 23 to 25, there is a
7 dispute about the 2019 rate case stipulation and the
8 resulting order and what was required of the company in
9 terms of the hourly usage data.

10 The question is, specifically, is Georgia Power
11 required to provide hourly usage data to all customers free
12 of charge as asserted by the coalition? And you're saying
13 no.

14 So if we take out the phrase "free of charge,"
15 because that wasn't written in those particular words in the
16 stipulation, would you say that the company was required to
17 provide hourly access to all residential and commercial
18 customers?

19 A (Witness Legg) No, it's not my understanding
20 that that was the requirement at all. As I read it -- and
21 again, this is not a legal interpretation. I'm not an
22 attorney. But as I read the order and have read the order
23 and was actually part of the 2019 rate case proceeding, my
24 understanding is that the Commission -- that the Commission
25 ordered the company to look at options to provide hourly

1 usage data and then bring recommendations back to the
2 Commission.

3 And then if any of those recommendations were
4 approved by the Commission, then we would try to implement
5 it, I believe by January 1st of 2022. I don't know that the
6 language -- I don't believe the language -- I don't have it
7 in front of me here -- says that the company is required to
8 provide hourly usage data for all customers.

9 Q Thank you.

10 Are you familiar with the Commission's
11 March 18th, 2021, order in which one of the options that was
12 brought by the company was approved by the Commission?

13 MADAM CHAIR PRIDEMORE: Ms. Brown?

14 MS. BROWN: Yes, ma'am.

15 I am sorry. I forgot to ask for his permission
16 to approach.

17 MADAM CHAIR PRIDEMORE: You may approach.

18 BY MS. BROWN:

19 Q If I could direct you, I believe it's the last
20 page of that order where all the "wherefores" begin.

21 A (Witness Legg) Yes.

22 Q Could you please -- you can either read it out
23 loud or to yourself, the first "wherefore, it is ordered."

24 A (Witness Legg) "Wherefore, it is ordered that
25 option one as provided in the company's February 11th, 2021,

1 filing shall be implemented in order to provide all
2 residential and commercial customers with access to hourly
3 usage data."

4 Q So at the very least, is it possible that the
5 Commission's understanding of what they were approving was
6 that all customers, residential and commercial, have access
7 to that data?

8 A (Witness Legg) It's possible. I would have to
9 read back through option one. I don't know if there was
10 wording in there that stated that there would be some
11 customers, like AMI opt-out, that wouldn't have that
12 information.

13 Q Okay. And then just --

14 A (Witness Legg) I'm sorry, go ahead.

15 Q No, please.

16 A (Witness Legg) Yeah. I was just going to say,
17 I don't have the details of option one here in front of me
18 and I wasn't involved in filing that.

19 VICE CHAIRMAN ECHOLS: Mr. Legg, as the crafter
20 of the motion, it was my intent that that would
21 happen, just for what it's worth.

22 MR. LEGG: Certainly, yes. And that's what the
23 company desires, Commissioner, is to make that
24 information available to all customers. You know, to
25 the extent we can, we are striving for that. So we

1 will be happy to check and see if there are any
2 customers that can't. It may be difficult for AMI
3 opt-out customers just because we literally don't
4 have the data, but -- since they've opted out of that
5 system, but we are happy to look into that.

6 VICE CHAIRMAN ECHOLS: And we only have, what,
7 about 400 customers that have opted out of AMI?

8 MR. LEGG: It's in the hundreds, yes, sir.

9 VICE CHAIRMAN ECHOLS: Yeah, so it's tiny.

10 MR. LEGG: Right. That's right.

11 BY MS. BROWN:

12 Q In our conversations with the company as
13 customers, we have been told that part of the reason that
14 the meter itself may not be either programmed to collect the
15 data or may not be capable of collecting the data. Would
16 the company support, is part of this cost-recovery request,
17 the cost to reprogram or replace meters so that all
18 residential and commercial customers can access this data?

19 A (Witness Legg) Well, I don't run the metering
20 department, and I don't -- I'm not familiar with the
21 limitations that you've just described there, but certainly
22 we would be glad to look into anything we can do to make
23 data available to customers.

24 MS. BROWN: Okay. Thank you.

25 MADAM CHAIR PRIDEMORE: Georgia Interfaith

1 Power & Light.

2 MS. WHITFIELD: No questions.

3 MADAM CHAIR PRIDEMORE: GA Solar.

4 MR. MORELAND: No questions.

5 MADAM CHAIR PRIDEMORE: GASEIA.

6 MR. THOMASSON: Gentlemen, I have a few
7 questions about TOU-RD, picking up on questions that
8 Commissioner Echols and Mr. Thomas asked you at the
9 beginning and I will not repeat theirs.

10 CROSS-EXAMINATION

11 BY MR. THOMASSON:

12 Q But on page 8 of your testimony on lines 5
13 through 8, you say that the TOU-RD rate was not designed to
14 be inherently more costly than the R rate, but it's actually
15 designed to be revenue neutral. Is that a fair read?

16 A (Witness Legg) Yes. For an average customer,
17 as originally designed. It was designed to be revenue
18 neutral for an average customer.

19 Q And when you say originally designed, I think
20 you mentioned either to Commissioner Echols or to Mr. Thomas
21 that that rate dates back to 2013 roughly?

22 A (Witness Legg) Yeah. I believe it was approved
23 in the 2013 case. And I believe that would still be true
24 today or close to true. Certainly the domestic class, all
25 the tariffs within that class since 2013 have received the

1 same percentage increase. So it may be off a hair -- you
2 know, a percent or two here or there for the average
3 customer, but I believe it would be essentially --

4 Q Yeah. That essentially was going to be my
5 question. Does that design from 2013 get refreshed or
6 updated to sort of ensure revenue neutrality or is it set it
7 and forget it?

8 A (Witness Legg) I don't know that the design
9 gets updated. But, again, in the 2016 -- or I'm sorry. In
10 the 2019 rate case, I believe, all the domestic rates
11 received the same percentage increase, subject to check.
12 But I think that entire group did, so -- so I think that
13 relationship would still hold.

14 Q Okay. And in the 2019 rate case, do you recall
15 that order directing the company to report back to the
16 Commission on the use of TOU-RD as the default rate for new
17 premises --

18 A (Witness Legg) Yes.

19 Q -- as part of that order?

20 Has the company included an actual report in
21 this rate case or in any filing since then or is it just --

22 A (Witness Legg) I don't know that we have
23 included a report in the rate case or in a particular
24 filing. We have certainly had discussions with staff along
25 the way about time and use residential demand, about

1 marketing the rates. That's something else that came out of
2 that order marketing the TOU-RD rate.

3 So we've certainly done that along the way.

4 And I -- I would say that, you know, the report -- part of
5 the way that we're reporting back to the Commission in this
6 case is talking about our plans for TOU-RD moving forward,
7 how many customers have signed up for the rate. We talk
8 about -- we talked about and filed the satisfaction survey
9 for customers that we talked about earlier that included
10 satisfaction rates for customers on the TOU-RD rate like
11 that. We didn't produce a specific report, though, just for
12 the rate case.

13 Q We were just looking to see through exhibits if
14 there was one. I wanted to make sure I didn't miss it if
15 there was.

16 A (Witness Legg) No.

17 Q With regard to the revenue neutrality, have you
18 reviewed other testimony in this proceeding where parties,
19 intervenors and staff, concluded that the EERD rate would be
20 higher for folks compared -- for a majority of customers
21 compared to the R rate and do you have opinions on that
22 analysis?

23 A (Witness Legg) Yes, I have. And I disagree
24 with it. That's actually the basis for one of the figures
25 on page 9 in our testimony. And it appears that the

1 analysis certainly was done on a population of time and use
2 RD -- or TOU-RD customers. And if you think about it, it
3 became the default rate for some customers, but also began
4 to be selected by some customers after 2019 when the company
5 started discussing rate options with each customer that
6 calls in to connect service.

7 And so we've gone from having about 7,000
8 customers on the rate to about 70,000 customers on the rate
9 in the last three years. Many of those are new premises.
10 And so -- because it was determined to be the default rate
11 for new premises in the 2019 case.

12 So what this illustrates, Figure 1 on page 9, a
13 comparison of customers on the residential rate were -- many
14 or most of the customers have been on the rate for a number
15 of years and their usage has matured is not necessarily an
16 apples-to-apples comparison to customers who are at newly
17 constructed premises on another rate. Because what we found
18 in analyzing that is over the first 24 months of usage at a
19 newly constructed premises, the usage increases
20 significantly. You can see that in the bars on Figure 1.

21 And we show months 1 through 6, 7 through 12,
22 13 through 18, and 19 through 24 how the usage -- the
23 average usage -- this isn't just for time-of-use residential
24 demand. It's across all new premises looking at 2020 and
25 2021, two years of history, and a little bit into 2022.

1 So it's just showing that as a new premises
2 matures, the usage increases. But if you think about it
3 logically, that actually would make sense.

4 A new premises is one that's just been built,
5 whether it's a new home or whether it's an apartment
6 building, something like that, a townhouse, there's the
7 construction process where the builder has construction
8 service at the site. There's a pole out in the yard.
9 There's a meter there.

10 But then eventually, when you get to the point
11 where you close it in and you get ready to finish the house,
12 Georgia Power comes and sets the permanent meter that the
13 house starts using -- you know, it goes on a standard rate.
14 It starts using energy.

15 And over time, as the builder completes that,
16 as they may put it up for sale, or for an apartment
17 building, it may be for lease for a few months before the
18 building gets built in, something like that, there's no one
19 living there so the usage is lower than if someone were
20 living there.

21 So this is just to point out that through that
22 process, over those first couple of years, that the usage
23 increases over time. And so to compare a mature rate with
24 1.8 million customers, like R, that has mostly customers
25 that have been on there for a long time, to a rate where a

1 lot of the customers are from new premises is not an
2 apples-to-apples comparison.

3 VICE-CHAIRMAN ECHOLS: Mr. Legg, imagine how
4 much better it can be from a demand response, from an
5 energy efficiency standpoint, if you sweetened up
6 this TOU-RD with something like a Sense or the Tempo
7 where then the customers are -- are helping us with
8 our load. And they are seeing those lights or
9 getting those messages and they're -- they're making
10 those adjustments not just to save themselves money,
11 but then it has the benefit for the entire system.

12 I just think we can -- I love the idea. I just
13 want us to make it better.

14 MR. LEGG: Yes.

15 BY MR. THOMASSON:

16 Q And to that point, I'm going to skip ahead one
17 question. Because Commissioner Echols had asked you earlier
18 similar to that about the tools and the price signals. And
19 I just wanted to ask specifically: Are there price signals
20 in TOU-RD with respect to the demand component?

21 Do customers have price signals to manage that
22 demand component and -- well, I'll let you answer that
23 question.

24 A (Witness Legg) Well, it depends on what you
25 mean by a price signal. So certainly if a customer gets a

1 high demand charge one month, they can go back. It doesn't
2 carry forward.

3 We were talking about a commercial rate earlier
4 where your demand could carry forward for the next
5 11 months. That's not the case in TOU-RD.

6 So you start off each billing month with a
7 clean state. So if you had a high demand on a particular
8 time, you could go back to My Power Usage, look at your
9 demand, see when that happened. You may be able to know:
10 Oh, yeah. We were doing this or that on that particular
11 day.

12 So that's one way that they could look at that
13 and take that as a price signal. Again, the stronger price
14 signal for TOU-RD is in the energy charge, having on-peak
15 and off-peak energy charges.

16 I would contrast that with the R rate, which is
17 the other one that we're talking about here. Again, in the
18 summer months, the R rate, the more you use, the more
19 expensive it gets. So the only price signal is stop using
20 electricity once you get past the first block because it's
21 just getting more expensive.

22 So I do think the TOU-RD rate sends a more
23 effective price signal and more accurate price signal than
24 the residential.

25 Q Than the R rate. But on page 10 of your

1 testimony, in the middle around lines 8 to 10, you discuss
2 the TOU-RD rate compared to the volumetric TOU-RD rates.

3 Would you agree that the TOU-RD rate has less
4 of a price signal for the overall bill than those volumetric
5 energy rates without a demand component?

6 A (Witness Legg) No. It has the same -- the
7 same, in that they both have on-peak and off-peak energy
8 charges. I would say that it probably does not do as good a
9 job collecting costs. Because, again, there are
10 demand-related -- we've talked here about customer-related,
11 energy-related, demand-related costs.

12 It has a demand component that matches better
13 with the costs that are incurred. So I think, again, it's
14 more accurate in the way it collects revenues according to
15 how the company incurs costs to serve its customers. Those
16 other energy-only rates don't have that component in them.

17 Q So it's your testimony that they have the same
18 amount of pricing going in and management with and without
19 the demand component?

20 A (Witness Legg) Well, there are different
21 demand -- they are different designs of rates. But, again,
22 they all have on-peak and off-peak energy charges to serve
23 as a price signal.

24 Q And I know in your testimony that you have
25 rejected recommendations for changes to the TOU-RD rate, but

1 did you review recommendations and other testimony in this
2 proceeding for improvements to that, like a time-of-use
3 component to the demand rate portion of that to offer a
4 better price signal for customers to control that piece of
5 the rate? And do you have an opinion on it?

6 A (Witness Legg) I did -- I did review that.
7 This rate is not designed with a time and use signal on the
8 demand charge. That's something that you can do. Lots of
9 demand rates have a time piece -- a time -- a
10 differentiation associated with them. Lots of them don't.

11 We were talking about our power and light
12 rates. We have a lot of commercial industrial rates that
13 have a peak demand that don't have a time component to it
14 and others do.

15 When this was designed -- again, back in
16 2013 -- the decision was made to not include a time
17 component on the demand. And that's generally just to make
18 sure that we're recovering the fixed costs that are incurred
19 to serve customers.

20 VICE-CHAIRMAN ECHOLS: Mr. Legg, we've kind of
21 got a car theme, you know, going today. Before you
22 and I drove Leafs -- I don't know if you ever had a
23 five-speed car of any sort.

24 MR. LEGG: I did.

25 VICE-CHAIRMAN ECHOLS: But, you know, you

1 had -- you usually have RPMs there and it has a -- it
2 has a red area; right?

3 MR. LEGG: Right.

4 VICE-CHAIRMAN ECHOLS: And that red line tells
5 you if you're -- if you've got too many RPMs, you can
6 damage -- damage the engine. And I guess for real
7 gear heads, they even want gauges for everything;
8 right?

9 They didn't want what was called the idiot
10 lights. Remember the idiots lights?

11 MR. LEGG: Right.

12 VICE-CHAIRMAN ECHOLS: That it just came on
13 after your car was overheated; right?

14 And, to me, that's -- we need -- we need gauges
15 on this range, we don't need idiot lights. And the
16 idiot light is going after the fact to see that --
17 you know, that I burned my car up.

18 So, again, I'm repeating myself. I just want
19 to make this better. I want signals so that people
20 can be successful with this rate.

21 MR. LEGG: And that's what we want, too,
22 Commissioner. I appreciate that. We want our
23 customers to be successful on all of our rates.

24 BY MR. THOMASSON:

25 Q And I did have one question to go back to the

1 revenue neutrality. I wanted to follow that line of
2 question since Commissioner Echols opened it.

3 But you mentioned this effect of the new
4 premises needing 24 months or whatever the maturity period
5 is and not having an impact on the analysis.

6 Has the company done any recent analysis that
7 would control for that by looking only at customers that
8 aren't in new premises, but maybe switch from the R rate to
9 TOU-RD?

10 A (Witness Legg) We have not. Again, because the
11 population really has just increased in such a short period
12 of time, so we haven't looked at that. It may be some point
13 out in the future we can look at that when we have more
14 mature accounts to look at.

15 Q Okay. Quick question on the interconnection
16 fee, which is on page 19 of your testimony. On page-- on
17 lines 10 to 12, you repeat what was basically your testimony
18 in direct in this proceeding, which is that the company
19 believes the interconnection fees don't vary based on
20 project size for customer regeneration; is that correct?

21 A (Witness Legg) We say it does not vary
22 significantly based on the size of the facility.

23 Q Significantly.

24 A Actually, the cost in these fees, which are the
25 application, the administrative costs, you know, billing,

1 things like that, analysis, impact study fees, witness
2 testing fees, things like that.

3 Q Did you review the testimony from Mr. Lucas in
4 this case where he made the case that they do vary by system
5 size?

6 A (Witness Legg) I did, yes.

7 Q Do you have an opinion or a rebuttal to that
8 testimony?

9 A (Witness Legg) I don't. I mean, this -- this
10 is based on our experts in the renewables area that do
11 these. You know, that administer this, set up accounts,
12 look at these charges. And that's their -- that's their --
13 that's the company's view on this.

14 MR. THOMASSON: Okay. No more questions.

15 MADAM CHAIR PRIDEMORE: Georgia Watch.

16 If you want to go, you can go.

17 MS. COYLE: No questions.

18 MADAM CHAIR PRIDEMORE: Okay. The Kroger
19 Company.

20 (No response.)

21 MADAM CHAIR PRIDEMORE: Kroger.

22 (No response.)

23 MADAM CHAIR PRIDEMORE: All right. MARTA.

24 MS. STURM: No questions.

25 MADAM CHAIR PRIDEMORE: Resource Supply

1 Management.

2 MR. CLARKSON: No questions.

3 MADAM CHAIR PRIDEMORE: Sierra Club.

4 MS. ARIZA: No questions.

5 MADAM CHAIR PRIDEMORE: SACE and Southface.

6 MR. DOWDY: Madam Chairman, we have witnesses
7 that are going to address their testimony. So no
8 questions.

9 MADAM CHAIR PRIDEMORE: USDOD.

10 MR. HEWITSON: Hold on. Before that happens,
11 may I ask what that meant?

12 Mr. Dowdy, do you mean in the net metering
13 portion of surrebuttal?

14 MR. DOWDY: I've got --

15 MR. HEWITSON: This is the rebuttal of the main
16 rate case.

17 MR. DOWDY: I understand that. But we've
18 got -- the same issues presented here are also
19 incorporated in what we will be addressing when we
20 have witnesses on the stand.

21 MADAM CHAIR PRIDEMORE: Mr. Dowdy has his own
22 witnesses, Mr. Hewitson.

23 His answer is no, but we're making things hard
24 today, I mean, so...

25 Go ahead, Ms. Medlyn.

1 CROSS-EXAMINATION

2 BY MS. MEDLYN:

3 Q Good afternoon. Emily Medlyn on behalf of the
4 United States Department of Defense and All Other Federal
5 Executive Agencies.

6 A (Witness Legg) Good afternoon.

7 Q On page 12, lines 23 through 26 of your
8 rebuttal testimony, you state that Mr. Blank proposes to
9 reduce CBLs when customers install generation that runs at
10 least 6,000 hours, 68 percent of the year, even though no
11 load has been removed. For almost one-third of the year,
12 the customer's usage on the system would be the same as it
13 was before the installation of the generation.

14 But Dr. Blank does not actually state that in
15 his testimony, does he?

16 A (Witness Legg) I believe there is a reference
17 to the 6,000 hours. I don't have his testimony in front of
18 me here.

19 Q Okay. So you could not provide a reference to
20 it?

21 Okay. I do have -- I do have a copy of his
22 testimony. This has already been marked into the record,
23 but I do have copies for everyone.

24 MADAM CHAIR PRIDEMORE: You may approach.

25 MS. MEDLYN: Okay.

1 MADAM CHAIR PRIDEMORE: Or maybe Mr. Thomas can
2 help you.

3 Thank you, Mr. Thomas.

4 MS. MEDLYN: If anyone else would like a
5 copy --

6 MR. HEWITSON: I would.

7 MR. LEGG: And I would point out, this doesn't
8 say his testimony. I don't know if it may have been
9 from the stand or from his testimony.

10 BY MS. MEDLYN:

11 Q Okay. If you would just look at page 8 of his
12 direct testimony, that first line of questions.

13 A (Witness Legg) Yes.

14 Q Does that refresh your memory as to what he's
15 actually testified to?

16 A (Witness Legg) This describes the backup
17 service schedule, which actually has a requirement of 6,000
18 hours a year of generation.

19 Q Right. He does quote the backup schedule --

20 A (Witness Legg) Right.

21 Q -- regarding at lines 18. But what -- my
22 question is on the first Q and A as to what would happen if
23 a customer's generation fails to produce a hundred percent
24 of the time.

25 A (Witness Legg) Okay. Which line are you

1 specifically asking me about?

2 Q Okay. If you look at line 5, that failure of
3 an RTP customer with on-site generation to produce power
4 then automatically billed under the CBL standard bill
5 pursuant to the RTP rate schedule.

6 A (Witness Legg) Yes.

7 Q So he doesn't say that it has to -- it's only
8 6,000 hours; correct?

9 A (Witness Legg) Not here, he doesn't.

10 Q And if -- if the customer's generation fails to
11 produce a hundred percent of the time, then it would go to
12 the CBL rates; correct?

13 A (Witness Legg) Are you --

14 Q If you go onto the backup?

15 A (Witness Legg) So the backup -- so the way that
16 it's set up now, the backup rider is not available to RTP
17 customers.

18 So I don't know if this is -- are you saying
19 this is a hypothetical of what would happen if an RTP
20 customer were also on the backup service schedule?

21 Q If a customer has a generation that intended to
22 produce power a hundred percent of the time. That -- I
23 mean, that is Dr. Blank's -- his testimony is then if it
24 doesn't -- if it has a failure, for instance, then it would
25 be billed under that CBL rate.

1 A (Witness Legg) I -- I hear what you're saying,
2 but it also says: RTP customers who invest in on-site
3 generation capacity should be considered for a CBL reduction
4 as long as the customer subscribes to and pays for Georgia
5 Power backup service schedule.

6 He seems to be implying that the backup service
7 schedule would somehow apply to their CBL, which it does
8 not. You can't have backup service and RTP the way the
9 tariffs are written now. And it wouldn't be appropriate for
10 you to.

11 For a customer on RTP who signs up for -- just
12 on regular RTP without backup, who produces their own
13 electricity, any time they are generating electricity -- and
14 I guess it would depend on how much of their load they're
15 actually supplying.

16 It would drop their load through their RTP
17 kilowatt-hours and then eventually -- if they produced more,
18 it would -- or supplied more of their own electricity down
19 into their CBL, so they would get credits back at the CBL --
20 at RTP rate for that portion that dipped below their CBL,
21 just like any RTP customer.

22 But then if the generator fails, then they
23 would just be backup, instead of paying for their CBL and
24 paying for RTP. But, again, backup doesn't apply here
25 because it only applies to non-RTP customers on the PL or

1 governmental rate.

2 Q Okay. And is there a rationale as to why it
3 wouldn't apply to RTP customers?

4 A (Witness Legg) Yes. I think actually it would
5 probably end up being considerably more expensive. On RTP,
6 you have -- you have a customer set up on RTP, their CBL is
7 set based on when they originally take service to recover
8 the costs to serve that location.

9 And then when they're above their CBL, they buy
10 at RTP prices. When they're below, they get credits back at
11 RTP prices. The backup tariff actually is assuming that,
12 again, the generation will run 6,000 hours a year. The
13 customer contracts for the portion that Georgia Power has to
14 provide for them, you know, whether they're producing all of
15 their own electricity or just a part of it. We contract for
16 that difference.

17 And then any time they went above that, outside
18 of a couple of maintenance months that they contract for,
19 they would be penalized severely for that. Because, again,
20 they only contracted for Georgia Power to produce some of
21 that -- to supply some of their electricity and their
22 generator failed and we had to produce all of their
23 electricity.

24 So there are penalties that come in and
25 actually has a ratchet effect over the next 12 months. So I

1 would think an RTP customer with backup would be much more
2 expensive than just an RTP customer with generator.

3 Q Okay. Is the lack of the demand ratchet for
4 RTP customers -- is that the primary concern with allowing
5 RTP customers on to backup service?

6 A (Witness Legg) No. They are just two separate
7 ways to handle the same thing. They are two different
8 solutions to the same thing.

9 Q Okay.

10 A (Witness Legg) I don't know -- I don't know
11 that we've ever had an RTP customer add generation and
12 desire to be on the backup rider. Because I think
13 eventually -- I mean, we can evaluate it, but I think
14 eventually it would be more expensive for them.

15 Q Okay. Let's turn to page 13 of your rebuttal
16 testimony, lines 3 through 8.

17 A (Witness Legg) Yes.

18 Q Okay. And here you have concerns with
19 Dr. Blank's other recommendation to use two years of
20 historical load data without forcing RTP customers to come
21 off RTP for two years; correct?

22 A (Witness Legg) That's right.

23 Q And as the reason, you state that is because
24 of, quote, short-term changes to a customer's usage should
25 not result in the permanent conversion of embedded load into

1 marginal load on the RTP rate.

2 A (Witness Legg) Right.

3 Q Are you saying here that two years is
4 short-term?

5 A (Witness Legg) No. Well, what I'm saying is
6 two years helps avoid short-term situations like that. If
7 we were just to allow -- well, I should start by saying the
8 way -- the reason you can adjust your CBL or lower your CBL
9 is if you permanently remove load that was originally in the
10 CBL.

11 Again, when a customer goes on RTP, we set the
12 CBL level based on the cost to serve that customer. Any
13 changes to that, if they remove load that was originally in
14 that CBL, then we'll reduce the CBL.

15 We have seen situations in the past, whether it
16 is, let's say, demolition and construction of a building,
17 rebuilding like a school or something like that, it might
18 take 12 to 18 months. There were situations in the past
19 where an economic downturn lasted more than 12 months.

20 The Great Recession comes to mind. We had
21 customers that were down -- where their usage was low for
22 more than a year because they were idling in capacity. That
23 load didn't go away. The mechanical equipment to use
24 electricity was still there.

25 And when the recession went away, their

1 business picked up. When the recession ended and their
2 business picked up, their usage came right back.

3 So to permanently lower a CBL for a temporary
4 situation is what we're trying to avoid here. Because then
5 if the load comes back and we have lowered the CBL, now
6 they're buying a lot more at RTP. And that's costs that
7 were being recovered through the CBL, but now we can't
8 recover because we lowered it and somebody else has to pick
9 up the difference on that.

10 Q Okay. Just trying to understand your answer.
11 If an RTP customer who doesn't have a permanent load
12 reduction wants a reevaluation --

13 A (Witness Legg) Right.

14 Q -- of RTP, right now they have to come off of
15 RTP for two years?

16 A (Witness Legg) If they want to reset their CBL,
17 yes.

18 Q Right. And Dr. Blank's recommendation was you
19 could use, instead, two years of historical data. And I
20 think your rebuttal testimony said that that would
21 constitute a short-term change?

22 A (Witness Legg) Right. So, for instance, in the
23 example of the Great Recession, just because two years of my
24 historical usage is lower than my CBL, that doesn't mean
25 that that's a permanent change to my load. It may have just

1 been lower during the recession and I'm going to bring it
2 right back up when the recession is over.

3 Q Is there a point in time where you would not
4 consider that short-term, like four years or ten years?

5 A (Witness Legg) Well, two years is what it's
6 actually set at in the rules and regulations. It says
7 that -- I'm sorry. In the RTP tariff, it says: If the
8 customer comes off for two years, then it would be able to
9 reset its CBL at its actual load.

10 MS. MEDLYN: Okay. Thank you. That's all I
11 have.

12 MADAM CHAIR PRIDEMORE: Redirect.

13 MR. HEWITSON: Madam Chair, no redirect. I
14 can't excuse -- I can't ask that they be excused
15 since they will be appearing later in the hearing,
16 but I will ask that they be allowed to step down.

17 MADAM CHAIR PRIDEMORE: You are allowed to step
18 down. Thank you.

19 (Witness stepped down.)

20 MADAM CHAIR PRIDEMORE: Jamie Barber, Timothy
21 Cook, Glen Watkins.

22 Thereupon,

23 JAMIE BARBER,
24 TIMOTHY COOK,
 GLENN WATKINS,

25 having been duly sworn, testified as follows:

1 DIRECT EXAMINATION

2 BY MR. THOMAS:

3 Q Ms. Barber, I'll start with you. Can you
4 please state your full name, by whom you're employed, and
5 your responsibilities for the record.

6 A (Witness Barber) Jamie Barber. I'm employed by
7 the Georgia Public Service Commission. And I'm the director
8 of energy efficiency and renewable energy unit.

9 Q Thank you.

10 Mr. Cook, same question.

11 A (Witness Cook) My name is Timothy Cook. I work
12 for the Public Service Commission for the energy -- the
13 renewable energy division as a utilities engineer.

14 Q Mr. Watkins.

15 A (Witness Watkins) My name is Glenn Watkins.
16 I'm president and senior economist at Technical Associates,
17 an economic consulting firm. Obviously represent the
18 Commission staff in this case.

19 Q Thank you.

20 Ms. Barber, on November 18th of this year, did
21 you cause -- did you file or cause to be prefiled 36 pages
22 of rebuttal testimony in question-and-answer format, along
23 with 12 exhibits, including one trade secret Exhibit BC --
24 BCW-1 through BCW-12, with the trade secret being BCW-11.

25 A (Witness Barber) Yes. That's correct.

1 Q Do you have any corrections you need to make to
2 your prefiled testimony at this time?

3 A (Witness Watkins) Well, actually we may have
4 revisions. And I'll ask the Commissioners what they prefer.

5 As you may know, the company -- Mr. Legg and
6 Evans discovered an error in some of their calculations.
7 And so my testimony, as filed, reflects the original filed.

8 I'm happy to -- there's about eight or ten
9 numbers that would change. Would it help you or do you --
10 are you aware of the numbers as they are? Whatever you
11 prefer.

12 MADAM CHAIR PRIDEMORE: We're aware of the
13 errata as filed. So speak to the testimony as the
14 errata filed, sir.

15 MR. WATKINS: As the errata?

16 MADAM CHAIR PRIDEMORE: As the correct -- the
17 corrected.

18 MR. WATKINS: Okay. So with that, yes, I will
19 have a few revisions.

20 MADAM CHAIR PRIDEMORE: That's fine.

21 MR. WATKINS: Yes, ma'am.

22 On page 15 of our supplemental, in Table 1,
23 where you see the 1,093, that should be 560.

24 And the number below it, the 284, should be
25 287. And the total, the 1,356, should be \$826.

1 And then on line 6 in the question where it
2 says 1,093, it should say 560.

3 On line 8, where it says 1,093, it should say
4 560.

5 And then on line 18, where it says 1,093, it
6 should say 560.

7 I'm getting there. Page 16, line 1, where it
8 says 1,093, it should say 560.

9 Line 6, where it says 1,093, it should say 560.

10 Line 13, where it says 1,093, it should be
11 revised to 560.

12 Line 15, where it says 284, it should be 287.

13 Line 17, where it says 284, it should be 287.

14 A couple more. Page 18, please, line 16, where
15 it says 284, it should be 287.

16 Line 18, where it says 284, it should be 287.

17 And line 19, where it says 1,418,434, it should
18 be 1,435,000.

19 So that would reflect the corrections that the
20 company made after we filed our testimony.

21 BY MR. THOMAS:

22 Q Thank you, Mr. Watkins.

23 And with the corrections that you just made, if
24 I were to ask you the same questions today under oath, would
25 your answers be the same as set forth in your prefiled

1 direct testimony?

2 A (Witness Watkins) They would. But they're not
3 corrections. They were simply revisions through an update
4 the company made.

5 MR. THOMAS: Thank you.

6 Madam Chair, the court reporter has been
7 provided a copy of the testimony and I would ask that
8 the testimony be copied into the record as if given
9 here today.

10 (Whereupon, the prefiled direct testimonies
11 of Jamie Barber, Timothy Cook, and Glenn Watkins
12 follows:)

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BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

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

JOINT SUPPLEMENTAL
DIRECT TESTIMONY

AND EXHIBITS

OF

JAMIE BARBER,
TIMOTHY COOK,
AND
GLENN A. WATKINS

ON BEHALF OF THE
GEORGIA PUBLIC SERVICE COMMISSION
PUBLIC INTEREST ADVOCACY STAFF

NOVEMBER 18, 2022

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III.	STAFF’S ANALYSIS OF RNR MONTHLY-NETTING	14
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LIST OF EXHIBITS

<u>Staff Exhibit #</u>		<u>Description</u>
Staff Exhibit __ BCW-1	–	Resume of Jamie Barber
Staff Exhibit __ BCW-2	–	Resume of Timothy Cook
Staff Exhibit __ BCW-3	–	Resume of Glenn A. Watkins
Staff Exhibit __ BCW-4	–	Company’s Response to STF-DEA-1-3
Staff Exhibit __ BCW-5	–	Company’s Response to STF-TAI-8-9
Staff Exhibit __ BCW-6	–	Company’s Response to STF-DEA-1-2
Staff Exhibit __ BCW-7	–	Company’s Response to STF-DEA-1-4
Staff Exhibit __ BCW-8	–	Company’s Response to STF-TAI-8-19
Staff Exhibit __ BCW-9	–	Average R Rate Monthly Bills
Staff Exhibit __ BCW-10	–	Georgia’s Behind the Meter Solar Ranking
Staff Exhibit __ BCW-11	–	TRADE SECRET– GPC’s Solar Revenue Requirement
Staff Exhibit __ BCW-12	–	Unbundled Generation plus Transmission Revenues

I. INTRODUCTION

Q. PLEASE STATE YOUR NAMES AND BUSINESS ADDRESSES.

A. Our names are Jamie Barber and Timothy Cook, 244 Washington, Street, SW, Atlanta, Georgia 30334 and Glenn A. Watkins, 6377 Mattawan Trail, Mechanicsville, Virginia 23116.

Q. MS. BARBER PLEASE STATE YOUR TITLE, EMPLOYER, EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I am the Director of the Energy Efficiency and Renewable Energy Unit for the Georgia Public Service Commission ("Commission"). My educational background and work experience are provided in my resume, which is attached as Staff Exhibit __ BCW-1.

Q. MR. COOK PLEASE STATE YOUR TITLE, EMPLOYER, EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I am a Utilities Engineer for the Energy Efficiency and Renewable Energy Unit of the Commission. My educational background and work experience are provided in my resume, which is attached as Staff Exhibit __ BCW-2.

Q. MR. WATKINS WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A. Except for a six month period during 1987 in which I was employed by Old Dominion Electric Cooperative, as its forecasting and rate economist, I have been employed by

1 Technical Associates continuously since 1980. During my 42-year career at Technical
2 Associates, I have conducted hundreds of marginal and embedded cost of service, rate
3 design, cost of capital, revenue requirement, and load forecasting studies involving
4 numerous electric, gas, water/wastewater, and telephone utilities, and have provided expert
5 testimony in Alabama, Arizona, Delaware, Georgia, Illinois, Indiana, Kansas, Kentucky,
6 Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Jersey, North
7 Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West
8 Virginia. A more complete description of my education and experience is provided in Staff
9 Exhibit __ BCW-3.

10 **Q. MS. BARBER, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS**
11 **COMMISSION?**

12 A. Yes. I testified in each of the 1998 through 2009 United Cities Gas Company (now known
13 as Atmos Energy Corporation) Gas Supply Plan Proceedings. I also testified in Docket No.
14 10270, GPSC Determination of Lack of Market Constraints on Atlanta Gas Light
15 Company's Commodity Sales; Docket No. 11114, Rule Nisi Against United Gas
16 Management of Georgia, Inc.; Docket No. 14311, Earnings Review to Establish Just and
17 Reasonable Rates for Atlanta Gas Light Company; Docket No. 15296 Service Quality
18 Standards for Certified Marketers and Regulated Provider; Docket No. 18638-Atlanta Gas
19 Light Company's 2004/2005 Rate Case; Docket No. 20298 Atmos Energy Corporation's
20 2005 Rate Case; Docket No. 27163 Atmos Energy Corporation's 2008 Rate Case; Docket
21 No. 30442 Atmos Energy's 2010 Rate Case; Docket No. 36498 Georgia Power Company's
22 2013 IRP Filing; Docket No. 36499 Georgia Power Company's 2013 Demand Side
23 Program Certification; Docket No. 37854, Georgia Power Company's Application for the

1 Certification of the Power Purchase Agreements for Wind Resources from the Blue
2 Canyon II and Blue Canyon VI Wind Farms; Docket No. 38877, Georgia Power
3 Company's Application for the Certification of the 2015 and 2016 Advanced Solar
4 Initiative Prime Power Purchase Agreements and Request for Approval of the 2015
5 Advanced Solar Initiative Power Purchase Agreements, Docket No. 36989 Georgia Power
6 Company's 2013 Rate Case, Docket No. 40161 Georgia Power Company's 2016 IRP
7 Filing, 40162 Georgia Power Company's 2016 Demand Side Program Certification,
8 Docket No. 41596, Georgia Power Company's Application for the Certification of the
9 2018/2019 Renewable Energy Development Initiative Utility Scale Power Purchase
10 Agreements, Docket No. 41734, Georgia Power Company's Application for the
11 Certification of the 2018/2019 Renewable Energy Development Initiative Utility Scale
12 Power Purchase Agreements for the Commercial and Industrial Program, Docket No.
13 43210 Georgia Power Company's 2019 IRP Filing, Docket No. 43211 Georgia Power
14 Company's 2019 Application for the Certification, Decertification, and Amended
15 Demand-Side Management Plan, Docket No. 42516 Georgia Power Company's 2019 Rate
16 Case, Docket No. 44160 Georgia Power Company's 2022 Integrated Resource Plan and
17 Docket No. 44161 Georgia Power Company's Application for the Certification,
18 Decertification and Amended Demand Side Plan.

19 **Q. MR. COOK, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS**
20 **COMMISSION?**

21 **A.** Yes. I testified in Docket No. 43814 Georgia Power Company's Application for the
22 Certification of the 2022/2023 Utility Scale Renewable Power Purchase Agreements.,
23 Docket Nos. 4822, 16573 and 19279 Georgia Power Company's PURPA Avoided Cost

1 Dockets, and Docket No. 44160 Georgia Power Company's 2022 Integrated Resource
2 Plan.

3 **Q. MR. WATKINS, HAVE YOU APPEARED BEFORE THIS COMMISSION ON**
4 **PREVIOUS OCCASIONS?**

5 A. Yes. I appeared as a witness on behalf of the Commission Public Interest Advocacy
6 ("PIA") Staff ("Staff") in Georgia Power Company's ("Georgia Power" or "Company")
7 general rate cases during 2007, 2010, and 2013. Furthermore, I provided testimony on
8 behalf of the Staff many years ago in a Savannah Gas and Electric case.

II. BACKGROUND

9 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

10 A. In the July 29, 2022 Georgia Power Integrated Resource Plan ("IRP") Order, the
11 Commission ordered Staff and Georgia Power to address the structure and pricing of the
12 Renewable and Non-Renewable ("RNR") tariff in the Company's 2022 Rate Case.
13 Specifically, the Commission approved the following motion from Commissioner Shaw:

14 Rather than continuing to try to address rooftop solar with a series
15 of temporary and partial measures where some customers receive
16 net metering while others receive only avoided cost or, in some
17 cases, nothing at all, I move that the Commission direct Staff and
18 the Company to each address the appropriate structure and pricing
19 of the RNR-10 tariff in the current rate case so that the Commission
20 can move towards a fair and long term way of addressing the issue.

21
22 In this IRP, we simply do not have the cost information necessary to
23 set just and reasonable rates, terms, and conditions for rooftop solar.

1 In addition, we do not have the information to determine whether or
2 how such rates, terms, and conditions would impact other
3 customers. Under my motion, the parties in the rate case would have
4 the opportunity to provide, test, and challenge cost-based data and
5 the Commission would have more options than simply deciding
6 whether or not to continue temporarily doling out net metering to a
7 subset of customers.

8 Based on the Commission's decision in the 2022 IRP, a modification to the Procedural and
9 Scheduling Order ("PSO") for the 2022 Georgia Power Rate Case was approved. The
10 modifications to the 2022 Rate Case PSO included the following dates for the filing of
11 testimony to address the RNR monthly netting issues: October 20, 2022 for the Company
12 to file Supplemental Direct Testimony; November 18, 2022 for other parties to file
13 Supplemental Direct Testimony; and November 23, 2022 for the Company to file
14 Supplemental Rebuttal Testimony. Our testimony responds to the recommendations
15 provided in the Supplemental Direct Testimony of Company Witnesses Larry Legg and
16 Lee Evans and Dr. David Gattie.

17 **Q. PLEASE SUMMARIZE THE COMPANY'S RECOMMENDATIONS**
18 **REGARDING THE RNR MONTHLY NETTING ISSUES THAT ARE TO BE**
19 **ADDRESSED IN THIS RATE CASE.**

20 **A.** In the Supplemental Direct Testimony of Lee Evans and Larry Legg, the Company
21 included three recommendations. First, the Company proposed that the RNR monthly
22 netting cap of 5,000 installations not be expanded. Second, the Company proposed that all
23 customers who enroll in RNR on or after January 1, 2023 be required to take service under
24 a three-part rate that includes a demand charge, such as Time of Use-Residential Demand
25 ("TOU-RD"). Third, the Company proposed the development of a formal framework for

1 the Commission referral of consumer complaints to the Consumer Protection Division of
2 the Georgia Attorney General's Office (Page 2, lines 12-23). In the Supplemental Direct
3 Testimony of Dr. Gattie, he recommended that the Commission reject expanding Georgia
4 Power's monthly netting program for compensating customers with behind the meter
5 ("BTM") generation in Georgia.

6 **Q. IS GEORGIA POWER REQUIRED TO PURCHASE EXCESS GENERATION**
7 **FROM CUSTOMER RENEWABLE GENERATOR FACILITIES?**

8 A. Yes. The Georgia Cogeneration and Distributed Generation Act of 2001 ("Cogen Act")
9 requires Georgia Power to purchase excess renewable energy from its customers. The
10 Georgia General Assembly established the Cogen Act to encourage private investment in
11 renewable energy resources, stimulate in-state economic growth, enhance the continued
12 diversification of the state's energy resource mix, and reduce interconnection and
13 administrative costs. The Cogen Act was a result of the Federal Energy Regulatory
14 Commission's ("FERC") Public Utility Regulatory Policies Act of 1978 ("PURPA") which
15 was implemented to encourage the development of cogeneration and renewable energy
16 facilities in the United States. The Cogen Act requires electric service providers to
17 purchase renewable power from facilities with a peak generating capacity of not more than
18 10 kilowatts ("kW") for residential systems and 100 kW for commercial systems.

19 **Q. PLEASE DESCRIBE GEORGIA POWER'S RNR TARIFF AND THE ACTIONS**
20 **TAKEN BY THE COMMISSION IN GEORGIA POWER'S 2019 RATE CASE.**

21 A. Georgia Power developed the RNR tariff to comply with the Cogen Act. The first RNR
22 tariff was approved by this Commission in August 2002. Customers on the RNR tariff

1 with either a Renewable Energy Resource or Nonrenewable Energy Resource as defined
2 in the tariff can use such facilities to offset their usage and sell any excess energy back to
3 the Company.

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

10 Under RNR-Instantaneous Netting, all excess energy from a customer's system is credited
11 to the customer's bill at the solar avoided energy cost rate based on the Company's filing
12 in Docket No. 16573. Also, all of the energy delivered by Georgia Power to the customer's
13 premises is purchased from the Company at the retail rate.

14 In Docket No. 42516, in a February 6, 2020 Order Adopting Settlement as Modified, the
15 Commission concluded, after approval of a motion by Commissioner Echols, that the BTM
16 netting period for customers receiving service on the RNR tariff shall be changed from
17 instantaneous to monthly netting for the first 5,000 rooftop solar ratepayers or until new
18 installed capacity reaches 32 megawatts ("MW"), whichever occurs first. Under monthly
19 netting, a customer's usage is netted against generation that is supplied into the grid. In
20 this regard, and due to the R Rate inverted-block rate structure in the summer months and
21 a declining-block rate structure in the non-summer months, the effective value for the
22 netting per kilowatt hour ("kWh") that an individual customer receives varies depending

1 on the customer's total net usage and varies across the four summer months and eight non-
2 summer months.

3 **Q. WHEN DID THE COMPANY FILE AN UPDATED RNR TARIFF TO REFLECT**
4 **THE MONTHLY NETTING OPTION?**

5 A. On May 13, 2020, the Company filed the RNR-10 tariff to be in compliance with the Order
6 Adopting Settlement as Modified. There was a delay in filing the tariff due to the
7 Company's system not being able to implement monthly netting billing. For customers
8 receiving service on a TOU tariff, monthly netting was delayed until end of year 2020.
9 However, once a customer became active on the RNR tariff, the customer received the
10 appropriate netting dating back to January 1, 2020.

11 At the end of 2019, there were approximately 1,071 customers on the RNR Tariff with
12 approximately 11 MW of capacity according to the Company's response to STF-DEA-1-3
13 in the 2022 IRP proceeding and is being provided as Staff Exhibit __ BCW-4. These
14 customers were first to be offered monthly netting once the Company's billing system was
15 ready. Therefore, the new RNR-Monthly Netting option was available to nearly 4,000 new
16 RNR customers, up to the 32 MW capacity limit. The RNR-10 tariff was approved by the
17 Commission on June 2, 2020.

18 **Q. WHAT IMPACT HAS RNR MONTHLY NETTING HAD ON SOLAR ROOFTOP**
19 **APPLICATIONS?**

20 A. The Company provided RNR application information to Staff during a meeting on August
21 15, 2022. For the first half of 2020, new RNR interconnection requests averaged about 50

1 per month. Since that time, through August 2022, nearly 10,000 additional customers have
2 submitted an application for interconnection, although some of the applications may have
3 been duplicates.

4 **Q. WHEN DID RNR-MONTHLY NETTING REACH THE COMMISSION**
5 **APPROVED CAP?**

6 A. The 5,000 RNR Monthly-Netting cap was reached in mid-2021, although installations for
7 these customers were not completed until the latter half of 2022.

8 **Q. HOW MANY SOLAR ROOFTOP SYSTEMS HAVE BEEN INSTALLED TO**
9 **DATE?**

10 A. According to the Company's Response to STF-TAI-8-9 and provided as Staff Exhibit __
11 BCW-5, there are 7,297 customers on the RNR tariff with a combined capacity of
12 approximately 64.5 MW. More than 90% of these installations are residential rooftop solar
13 systems with an average size of approximately 7 kW. There are nearly 350 Commercial
14 RNR participants with an average system size of 44 kW and over 25 Industrial RNR
15 participants with an average system size of 89 kW. Summary data through 2021 can be
16 found in the Company's Response to STF-DEA-1-2 and is provided as Staff Exhibit __
17 BCW-6.

18 **Q. WHERE DO WE CURRENTLY STAND REGARDING THE CUMULATIVE**
19 **GENERATING CAPACITY REACHING 0.2% OF THE COMPANY'S PREVIOUS**
20 **YEAR ANNUAL PEAK DEMAND?**

1 A. This cumulative generating capacity is an aggregate of all customers on the RNR
2 instantaneous netting methodology, and does not include customers on RNR Monthly
3 Netting. The Company reported that, at the beginning of the year, the cumulative
4 generating capacity of RNR Instantaneous customers was approximately 2.2 MW, or only
5 0.014% of the Company's 2021 peak demand of 16,213 MW (Company's Response to
6 STF-DEA-1-4 and provided as Staff Exhibit __ BCW-7). However, since the cap for RNR
7 Monthly Netting was reached in mid-2021, more than 40 MW of additional capacity have
8 applied for RNR Instantaneous Netting according to Company's Response to STF-TAI-8-
9 19 and provided as Staff Exhibit __ BCW-8.

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

15 **Q. WHY DOES STAFF SUPPORT THE CONTINUED GROWTH OF CUSTOMER**
16 **OWNED GENERATION?**

17 A. Staff supports the continued growth of customer-owned generation, located behind the
18 customer's meter, because of its various benefits. First, customer owned generation,
19 primarily rooftop solar, provides customers with the option for reducing their energy bills,
20 supplying their own energy and potentially securing backup power. Secondly, customer
21 owned generation is primarily renewable energy, which contributes to Georgia's continued
22 transition to clean energy. Finally, customer owned generation reduces the Company's net

1 loads on the grid, requiring fewer Company-owned assets to be built and paid for by
2 customers.

3 **Q. ARE OTHER INCENTIVES AVAILABLE FOR SOLAR CUSTOMERS THAT**
4 **WOULD ENCOURAGE ROOFTOP SOLAR INSTALLATION IN ADDITION TO**
5 **MONTHLY NETTING?**

6 A. Yes. As the Company states in the Supplemental Direct Testimony of Lee Evans and Larry
7 Legg on pg. 16, line 6, the recent passage of the Inflation Reduction Act (“IRA”) extends
8 federal tax credits for solar installations which were due to phase out in the next few years.
9 The state of Georgia does not offer state incentives for solar installations.

10 **Q. DOES STAFF AGREE WITH THE COMPANY’S POSITION THAT THE IRA**
11 **WILL INCENTIVIZE SOLAR INSTALLATIONS SUCH THAT MONTHLY**
12 **NETTING WILL NOT BE NECESSARY TO ENCOURAGE SOLAR**
13 **INSTALLATIONS?**

14 A. No. Prior to the passage of the IRA, customers were already allowed certain tax incentives
15 toward the cost of installing solar facilities at their home or business. The solar tax
16 incentives of 30% in the IRA are not significantly different than those in effect in prior
17 years. Prior to the IRA, the incentive was 30% from 2007-2017 and 26% for 2020-2022.

18 **Q. HAVE OTHER STATE COMMISSIONS ADDRESSED CUSTOMER OWNED**
19 **GENERATION COMPENSATION POLICY IN RECENT PROCEEDINGS?**

20 A. Yes. Many states across the country have recently begun to address the question of what is
21 the appropriate compensation for customer generators. These states include North

1 Carolina, South Carolina, Florida, Arkansas, Mississippi, and Michigan, each of which
2 opened a dedicated docket for litigating their state's net energy metering ("NEM") policy.
3 It is also important to understand that each of these states, aside from Mississippi, have a
4 higher penetration of rooftop solar adoption than what currently exists in Georgia Power's
5 service area.

6 **Q. WHERE DOES GEORGIA CURRENTLY RANK IN REGARDS TO ROOFTOP**
7 **SOLAR ADOPTION?**

8 A. As shown in Staff Exhibit __ BCW-10, when only considering Georgia Power Company
9 service area due to limitations of EIA data, as of August 2022, Georgia ranks 37st for the
10 capacity of BTM solar installed. For comparison, Arkansas has twice the amount of solar
11 installed and is ranked 34th and 13th ranked Nevada has about ten times the amount
12 installed. Georgia is the eighth most populous state and has over three times the population
13 of both Arkansas and Nevada.

14 **Q. WHAT POLICIES HAVE THESE OTHER STATE COMMISSIONS ADOPTED**
15 **TO ADDRESS COMPENSATION FOR ENERGY EXPORTED BY ROOFTOP**
16 **SOLAR SYSTEMS?**

17 A. While each state has enacted its own unique policy, there are two distinct policy categories
18 that have been adopted by other state commissions. The first category consists of the
19 continuation of NEM with the addition of billing mechanisms such as minimum bills, TOU,
20 or demand rates. South Carolina is one example which requires future net metering
21 customers to be on a TOU rate and imposes a small minimum bill (similar in value to the
22 customer base charge). Duke Energy in North Carolina has filed a stipulation with other

1 stakeholders which would impose a minimum bill and non-bypassable charges for certain
2 riders (North Carolina Utilities Commission, Docket No. E-100, Sub 180). Arkansas also
3 chose this structure, allowing customers on demand-based rates to maintain net metering,
4 although non-demand-based customers will also receive net metering through 2022, at
5 which point, utilities may propose an alternate compensation rate, similar to the second
6 category below (Arkansas Public Service Commission, Docket No. 16-027-R).

7 The other category of NEM policy is what is often referred to as an export rate. An export
8 rate is the same mechanism as Georgia Power's instantaneous netting policy; however,
9 other states have set different values for their export rate other than the avoided cost.
10 Michigan's export (or "outflow" as they refer to it) rate is based on the retail rate, with the
11 portion of costs related to the distribution system removed (Michigan Public Service
12 Commission, Case No. U-20836). This mechanism compensates the customer generator
13 for the energy and capacity value of their energy, but does not compensate them for
14 distribution system costs. Utah also provides an export credit rate for solar equal to the
15 avoided energy cost plus total avoided generation, transmission, and distribution capacity
16 costs of 3.53 cents/kWh (Utah PSC October 30, 2020 Order in Docket No. 17-035-61).
17 Mississippi also uses this type of compensation for solar export rates as its rate is based on
18 avoided cost plus a substantial credit for Non-Quantifiable Expected Benefits of 2.5 cents
19 per kWh, and an additional credit for low-income customers of 2 cents per kWh
20 (Mississippi Public Service Commission, Docket No. 2021-AD-19).

III. STAFF'S ANALYSIS OF RNR MONTHLY NETTING

1 Q. IN ITS SUPPLEMENTAL FILING, DID GEORGIA POWER PROVIDE
2 RELEVANT "COST INFORMATION NECESSARY TO SET JUST AND
3 REASONABLE RATES, TERMS, AND CONDITIONS FOR ROOFTOP SOLAR?"

4 A. No. The Company simply conducted an analysis of the revenue erosion it confronts as a
5 result of: (a) customers reducing their energy requirements simply due to supplemental
6 self-generation; and (b) the netting value associated with RNR Monthly Netting.

7 Q. IN ITS SUPPLEMENTAL DIRECT TESTIMONY, DID GEORGIA POWER
8 PROVIDE "INFORMATION TO DETERMINE WHETHER OR HOW SUCH
9 RATES, TERMS, AND CONDITIONS WOULD IMPACT OTHER
10 CUSTOMERS?"

11 A. To some extent, yes. That is, and as mentioned above, the analyses conducted by Company
12 Witnesses Legg and Evans provides an estimate of the residential revenue erosion
13 attributable to rooftop solar. As a result, the Company asserts that this reduced revenue
14 must be made up by all other residential customers in order for the Company to achieve its
15 authorized residential revenue requirement. In other words, the Company's total cost of
16 service remains fixed (for all intents and purposes), but with rooftop solar there is less
17 kilowatt hours of consumption, which translates into less revenue. Therefore, the reduction
18 in revenue must be made up by all non-solar customers in order for the Company to recover
19 its total costs.

1 **Q. PLEASE EXPLAIN THE COMPONENTS OF COMPANY WITNESS LEGG'S**
2 **REVENUE EROSION ANALYSIS.**

3 A. On page 12 of the Company's Supplemental Direct Testimony, Mr. Legg provides Figure
4 3 showing the components of his calculated average revenue erosion of \$1,356 per
5 customer per year. This amount is comprised of three components as shown below:

TABLE 1	
Average Annual Revenue Erosion Due to Rooftop Solar	
Cost Shift Resulting from R Tariff	\$1,093
Additional Monthly Netting Cost Shift	\$284
Avoided Energy Savings/Benefits	(\$21)
Total Cost Shift	\$1,356

6 **Q. PLEASE EXPLAIN THE \$1,093 COMPONENT WITHIN COMPANY WITNESS**
7 **LEGG'S ANALYSIS.**

8 A. The \$1,093 revenue erosion is simply the reduction in revenue as a result of a customer
9 self-generating some of their energy requirements. To more fully explain, the Company
10 first approximated the net kWh consumed and delivered for average rooftop solar
11 customers based on 12 months of billing data. The Company then estimated the kWh
12 produced by the typical customer's rooftop solar, which then allowed them to estimate the
13 average energy requirements of a rooftop solar customer if they did not have rooftop solar
14 installed. The Company then priced these estimated monthly usages to determine what a
15 customer's bill would have been (net of fuel and MFF) if they did not have a solar system
16 installed. The difference between what a customer's bill would be without rooftop solar
17 and an estimate of that customer's bill due to reduced kWh purchased from Georgia Power
18 is \$1,093 per customer per year.

1 In short, the \$1,093 average annual revenue erosion per customer is simply the reduced
2 revenue due to a customer using less energy provided by Georgia Power due to that
3 customer's supplemental self-generation. To be clear, this amount has nothing to do with
4 monthly netting. It is simply reduced revenue attributable to a customer purchasing fewer
5 kWh from Georgia Power. As an analogy, if a customer replaced its heat pump with a
6 highly efficient unit, this \$1,093 component relates to the reduced revenue due to a
7 customer purchasing less energy than before.

8 **Q. IS IT APPROPRIATE TO CONSIDER THE REDUCED REVENUE SIMPLY DUE**
9 **TO A CUSTOMER USING LESS ENERGY BECAUSE THEY SELF-GENERATE**
10 **SOME OF THEIR ENERGY NEEDS?**

11 A. No. A customer is, and should be, able to use any legal means available to reduce their
12 energy purchased from Georgia Power. This would include energy conservation measures
13 as well as supplemental self-generation. Therefore, Mr. Legg's \$1,093 revenue erosion
14 component should not be considered.

15 **Q. PLEASE EXPLAIN THE \$284 REVENUE EROSION COMPONENT WITHIN**
16 **COMPANY WITNESS LEGG'S ANALYSIS.**

17 A. The \$284 revenue erosion reflects the difference between the customer's annual monthly
18 netting bill and the customer's annual bill under instantaneous netting.

19 **Q. PLEASE EXPLAIN THE NEGATIVE \$21 COMPONENT WITHIN COMPANY**
20 **WITNESS LEGG'S ANALYSIS.**

1 A. This amount reflects what Mr. Legg refers to as the avoided “production energy-related
2 costs per kWh” of 0.207¢. Because the revenue erosion components discussed above are
3 net of fuel, this 0.207¢ per kWh reflects the avoided non-fuel production cost.

4 **Q. DOES STAFF AGREE WITH THE ASSUMPTIONS AND MODELING**
5 **COMPANY WITNESS LEGG USED WITHIN HIS ANALYSIS?**

6 A. No. Mr. Legg’s analysis is based on a sample of 1,110 residential monthly netting
7 customers. While Staff has no objection to the use of a sample, Staff believes the
8 assumptions used by the Company to estimate the lost revenue from RNR customers
9 overinflate the bill savings that RNR customers receive primarily by overestimating the
10 production by customer facilities. However, more concerning is the lack of validation of
11 the Company’s methodology using historical data for estimating RNR customer solar
12 production and the customer’s consumption before the installation of their solar system.

13 Primarily, Staff has concerns about the Company’s use of the National Renewable Energy
14 Laboratory’s PVWatts Calculator for solar production estimations. According to the
15 Company’s response to STF-TAI-8-6, the Company used all the default inputs for the
16 PVWatts Calculator tool, except for a geographic location, which was set at one of four
17 locations in Georgia. The default options for the PVWatts Calculator assume a ground
18 mounted solar array with ideal south-facing orientation, no shading as a result of nearby
19 trees or structures, and no future system degradation. All of these factors provide a best-
20 case scenario for the first year of solar production and will lead to a significant overestimate
21 of the average rooftop solar system production, which will only increase the overestimate
22 as these systems degrade over time.

1 The Company has not provided or utilized any historical data from existing RNR customers
2 in order to validate the method it used to estimate RNR lost revenue. Without a benchmark
3 to historical data, we cannot ensure the accuracy of the Company's estimates of customer
4 usage prior to solar installation, or the appropriateness of the chosen customer load profiles
5 for representing solar customers. The Company should have extensive hourly data
6 provided by its Advanced Metering Infrastructure ("AMI") system as well as historical
7 hourly consumption for most, if not all, of the RNR customers. While the Company has
8 indicated that its historical data was inadequate to conduct its analysis (Response to STF-
9 TAI-8-7 part a), there appears that there was no attempt by the Company to use even a
10 subset of historical data to validate the accuracy of the methodologies used by the Company
11 for its analysis.

12 **Q. EARLIER YOU INDICATED THAT, TO SOME EXTENT, THE COMPANY**
13 **PROVIDED INFORMATION TO DETERMINE WHETHER OR HOW SUCH**
14 **RATES, TERMS, AND CONDITIONS WOULD IMPACT OTHER CUSTOMERS.**
15 **PLEASE ELABORATE ON THIS OBSERVATION.**

16 A. Company Witness Legg estimates that an average RNR customer receives \$284 per year
17 more under RNR-Monthly Netting than that customer would receive under RNR
18 Instantaneous Netting. He then multiplied this \$284 by an assumed level of 5,000 RNR
19 customers to arrive at a total revenue erosion of \$1,418,434 per year.¹ The current
20 residential revenue excluding fuel is \$2,935,169,922.² Therefore, the residential revenue
21 erosion attributable to monthly netting is 0.00048 (0.048%). To be clear, the monthly

¹ Per Georgia Power, Solar Cost Shift Analysis workpaper.xlsx.

² Per Georgia Power's revenue proof provided in response to Corrected STF-TAI-1-16.

1 netting impact on residential customers is less than five one-hundredths of one percent. By
2 any measure, this is *de minimis*.

3 **Q. DURING CROSS-EXAMINATION, COMPANY WITNESS LEGG**
4 **ACKNOWLEDGED THAT THE REVENUE EROSION DUE TO MONTHLY**
5 **NETTING CURRENTLY REPRESENTS A VERY SMALL PERCENTAGE OF**
6 **RESIDENTIAL REVENUE AND THAT THIS PERCENTAGE IS BASED ON 5,000**
7 **CUSTOMERS. HOWEVER, MR. LEGG IS CONCERNED THAT ROOFTOP**
8 **SOLAR WILL CONTINUE TO GROW SUCH THAT THE PERCENTAGE WILL**
9 **INCREASE IN THE FUTURE. IF RNR MONTHLY NETTING WERE TO**
10 **INCREASE BY A FACTOR OF TEN, WOULD THIS HAVE A MATERIAL**
11 **IMPACT ON THE REVENUE COLLECTED FROM THE RESIDENTIAL**
12 **CLASS?**

13 **A.** No. Even if RNR Monthly Netting were to expand by a factor of ten in the foreseeable
14 future, the revenue erosion associated with the program would represent approximately one
15 half of one percent (0.5%) of the Company's total residential revenue. At the same time,
16 it must be remembered that RNR customers receive monthly netting due to excess
17 generation that provides value to the Company and other ratepayers.

18 **Q. DOES STAFF FIND IT INCONSISTENT THAT THE COMPANY IS**
19 **CONCERNED ABOUT A REVENUE EROSION OF LESS THAN FIVE ONE-**
20 **HUNDREDTHS OF ONE PERCENT, WHICH IT REFERS TO AS A "COST**
21 **SHIFT"?**

1 A. Yes. While the Company is concerned with the residential revenue erosion of less than
2 five one-hundredths of one percent due to monthly netting, it is not at all concerned that
3 some classes and rate schedules are significantly over-contributing to costs while other
4 classes and rate schedules are significantly under-contributing to costs. The Company's
5 proposal in this case is to simply increase all rates by an equal percentage such that there
6 is no movement towards parity of cost of service across classes and rate schedules. This
7 decision, of course, results in significant cost shifting across classes and individual rate
8 schedules.

9 **Q. HAS STAFF CONDUCTED ANALYSES UTILIZING ACTUAL DATA**
10 **ASSOCIATED WITH GEORGIA POWER'S RNR MONTHLY NETTING**
11 **CUSTOMERS?**

12 A. Yes. In response to STF-TAI-4-1, the Company provided actual monthly usage data for
13 every RNR customer during Calendar Year 2021.³ This data included (on an individual
14 account and monthly basis) delivered kWh, excess generation kWh, and net kWh
15 (delivered minus excess generation). In this regard, delivered kWh represents the amount
16 of energy into the customer's meter; i.e., the customer's billed kWh before monthly netting.
17 Excess generation represents the amount of energy the customer provided to the grid and
18 is compensated for under the RNR Tariff. Then, in response to an informal request, the
19 Company provided a matching of each customer provided in response to STF-TAI-4-1 to
20 the 1,110 customers Company Witness Legg used in his sample analysis. The Company
21 could not identify eight customers that were included in its sample that were also provided

³ This data included 3,720 customers that included residential, commercial, and industrial net metering customers as well as those under net metering and instantaneous metering.

1 in response to STF-TAI-4-1. As such, Staff's sample is based on 1,102 customers (1,110
2 minus 8).

3 **Q. PLEASE IDENTIFY THE ANALYSES STAFF HAS CONDUCTED UTILIZING**
4 **ACTUAL MONTHLY NETTING USAGE DATA BY INDIVIDUAL ACCOUNT.**

5 A. Utilizing the sample of 1,102 net metering customers, Staff has evaluated the delivered
6 kWh, excess generation kWh, and net kWh for every customer's bill during 2021. In
7 addition, Staff calculated each customer's total monthly bill and level of monthly netting
8 during this period. In this regard, Staff's analysis is based on monthly netting consistent
9 with the approach utilized by Company Witnesses Legg and Evans. Finally, Staff
10 calculated the average R Rate customers' monthly bill separately for the summer and non-
11 summer periods. This was required due to the differential in the block rates between the
12 summer and non-summer periods.

13 **Q. PLEASE PROVIDE A SUMMARY OF STAFF'S ANALYSIS.**

14 A. The following table provides a summary of Staff's analysis wherein we compared average
15 monthly usages and revenues of monthly netting customers to all R Rate customers:
16

TABLE 2
Comparison of RNR Monthly Netting to
Typical R Rate Customer Characteristics

	Average Monthly		
	KWH		Total Bill
	Delivered	Net	
<u>Summer (4 mths.)</u>			
Monthly Netting Customers ⁴	1,268	1,028	\$152.35
		1,199 ⁵	
All R Rate Customers			\$169.68
<u>Non-Summer (8 mths.)</u>			
Monthly Netting Customers ⁴	1,016	748	\$93.06
All R Rate Customers		886 ⁵	\$106.48
<u>Annual</u>⁷			
Monthly Netting Customers	1,418	841	\$112.82
All R Rate Customers		991	\$127.55

- 1 On a delivered kWh basis, we see that the average monthly netting customer tends to be
2 somewhat larger than the average R Rate customer. On a net kWh basis, we then see that
3 the average monthly netting customer is billed for somewhat less energy than the average

⁴ Per detailed analysis of individual monthly bills using 1,102 sample RNR customers.

⁵ Average R Rate (no solar) kwh/mth. per Rate Design (STF-TAI-1-16).

R Rate Customers	1,748,229
R Rate Summer kWh	8,386,432,332
Avg. Summer kWh/mth.	1,199
R Rate Non-Summer kWh	12,397,323,306
Avg. Non-Summer kWh/mth.	886
Weighted Annual kWh/mth.	991

⁶ Per Staff Exhibit BCW-9.

⁷ Weighted average: [(Non-Summer x 8 mths.) + (Summer x 4 mths.)] ÷ 12.

1 R Rate customer. Although the average monthly bills for RNR Monthly Netting customers
2 are somewhat lower than those for the average R Rate customers, monthly netting
3 customers provide a substantial level of revenue to the Company, and at the same time,
4 provide value to the Company and all other customers by supplying electric energy onto
5 the grid.

6 **Q. WHY IS STAFF'S ANALYSIS AND FINDING THAT RNR MONTHLY NETTING**
7 **CUSTOMERS CONTRIBUTE A SIGNIFICANT LEVEL OF REVENUE TO THE**
8 **COMPANY PARTICULARLY RELEVANT?**

9 A. The ratemaking process is the result of averaging. From a theoretical standpoint, the cost
10 to provide service varies for every single customer. As examples, due to the amount of
11 distribution equipment required to serve sparsely populated areas, it may cost more on a
12 per kW or kWh basis to serve rural customers relative to suburban or urban customers.
13 Similarly, because there are fewer kWh to recover revenue from residential customers that
14 use natural gas for heating, it may cost more on a per kW or kWh basis to serve these
15 customers relative to customers that use electricity for both heating and cooling. However,
16 within the ratemaking calculus, we do not distinguish between these two examples or any
17 other criteria that affects individual costs. As such, the average monthly revenue
18 contributed by a monthly netting customer of \$112.82 (\$1,354 per year) is significant.

19 **Q. DURING CROSS-EXAMINATION, COMPANY WITNESS LEGG TESTIFIED**
20 **THAT APPROXIMATELY 20% OF THE RNR MONTHLY NETTING BILLS**
21 **HAD ZERO NET KWH. HAS STAFF INVESTIGATED WITNESS LEGG'S**
22 **STATEMENT IN THIS REGARD?**

A. Yes. As indicated earlier, the Company provided every RNR customer's billing data for each month of 2021. The following table provides the sample number of monthly netting bills in which net kWh is less than or equal to zero and those that are greater than zero:

TABLE 3
Monthly Netting RNR Bills With
Net kWh Less Than or Equal to Zero
(2021)

Month	Net kWh ≤ 0	Net kWh > 0	Total	Percent ≤ 0
Jan.	26	1,075	1,101	2.4%
Feb.	53	1,049	1,102	4.8%
Mar.	210	892	1,102	19.1%
Apr.	411	691	1,102	37.3%
May	292	810	1,102	26.5%
Jun.	96	1,006	1,102	8.7%
Jul.	42	1,060	1,102	3.8%
Aug.	27	1,075	1,102	2.5%
Sep.	80	1,022	1,102	7.3%
Oct.	129	973	1,102	11.7%
Nov.	85	1,017	1,102	7.7%
Dec.	22	1,080	1,102	2.0%
Total	1,473	11,750	13,223	11.1%

While about 11% of the annual monthly netting bills had net kWh less than or equal to zero, it is important to observe that the majority of these bills occurred during low cost shoulder months and that during the peak high cost months, the percentage of bills with net kWh less than or equal to zero is very small.

Q. HAS STAFF EVALUATED THE LEVEL OF MONTHLY NETTING CUSTOMERS THAT HAD ZERO OR NEGATIVE NET KWH?

A. Yes. The following table shows the distribution of the sample monthly netting bills with zero or negative net kWh during 2021:

TABLE 4
RNR Bills with Months of Negative Net KWH

No. of Months	No. of Cust.	% of Total	Accum. Percent
0	653	59.26%	59.26%
1	116	10.53%	69.78%
2	106	9.62%	79.40%
3	86	7.80%	87.21%
4	33	2.99%	90.20%
5	31	2.81%	93.01%
6	23	2.09%	95.10%
7	19	1.72%	96.82%
8	15	1.36%	98.19%
9	10	0.91%	99.09%
10	4	0.36%	99.46%
11	2	0.18%	99.64%
12	4	0.36%	100.00%
	1,102	100.00%	

As can be seen above, almost 80% (79.40%) of the monthly netting customers had two or fewer months of zero or negative net kWh during 2021 and about 90% (90.20%) of these customers had four or fewer months of zero or negative net kWh.

In addition, Staff evaluated the distribution of monthly netting customers that had bill credits as shown in the table below:

No. of Months	No. of Cust.	% of Total	Accum. Percent
0	1,078	97.82%	97.82%
1	11	1.00%	98.82%
2	9	0.82%	99.64%
3	4	0.36%	100.00%
4	0	0.00%	100.00%
5	0	0.00%	100.00%
6	0	0.00%	100.00%
7	0	0.00%	100.00%
8	0	0.00%	100.00%
9	0	0.00%	100.00%
10	0	0.00%	100.00%
11	0	0.00%	100.00%
12	0	0.00%	100.00%
	1,102	100.00%	

As indicated above, almost 98% (97.82%) of the monthly netting customers had no bill credits during 2021 and no customer had more than four months of bill credits during 2021.

Q. HAS STAFF CONDUCTED ANALYSES OF POSSIBLE ALTERNATIVE TO VALUE THE EXCESS GENERATION EXPORTED TO THE GRID?

A. Yes. The valuation of excess generation supplied to the grid is a policy decision for the Commission. As such, Staff is providing a range of possible values for the excess solar energy that is supplied to the grid.

As mentioned earlier, under the current monthly netting mechanism, the value of solar energy supplied to the grid varies by not only season but also varies depending on a customer's total delivered kWh. Due to the inverted-block rate structure in the four summer months, a larger usage customer receives a higher monthly netting value per kWh

1 of solar energy supplied to the grid than a smaller usage customer that supplies solar energy
2 to the grid. For example, under current rates, a large usage customer that has a monthly
3 delivered kWh of 1,200 kWh will receive monthly netting value of 15.68¢ per kWh while
4 a customer with monthly delivered kWh of 650 kWh will only receive a monthly netting
5 value of 10.36¢ per kWh.

6 Similarly, due to the declining-block rate structure in the eight non-summer months, a
7 larger usage customer receives a lower monthly netting value per kWh of energy supplied
8 to the grid than a smaller usage customer. For example, a large usage customer that has
9 monthly delivered kWh of 1,200 kWh will receive a monthly netting value of 9.12¢ per
10 kWh while a customer with monthly delivered kWh of 650 kWh will receive a higher
11 monthly netting value of 10.29¢ per kWh. Staff is of the opinion that the value of excess
12 solar generation supplied to the grid is the same per kWh for both a large usage customer
13 and for a small usage customer.

14 Based on the 2021 usage characteristics of the sample, Staff has calculated that the annual
15 weighted average solar netting for monthly netting customers is about 10.22¢ per kWh
16 (9.01¢ in the eight non-summer months and 12.94¢ in the four summer months).

17 In evaluating alternative ways to value solar energy exported to the grid, Staff first
18 considered the capital costs and attendant implicit revenue requirement per kWh associated
19 with Georgia Power's owned solar facilities that are included in rate base. Georgia Power's
20 customers are paying for the value of Company-owned solar facilities such that a surrogate
21 for the value of rooftop solar pumped into the grid can be thought of as the same as the
22 value of Company-owned solar.

1 **Q. PLEASE EXPLAIN STAFF'S ANALYSIS OF THE REVENUE REQUIREMENT**
2 **PER KWH ASSOCIATED WITH GEORGIA POWER'S SOLAR FACILITIES.**

3 A. In response to STF-TAI-1-5, the Company provided an itemization of each solar facility's
4 net plant, depreciation, and kWh output during the forecasted test year of 2023. As a result,
5 Staff was able to calculate the fixed (capital) cost revenue requirement per kWh of the
6 Company's solar facilities. This analysis is provided in Trade Secret Staff Exhibit ____
7 BCW-11. As indicated in this Exhibit, ratepayers will pay 8.336¢ per kWh for Georgia
8 Power solar energy utilizing the Company's proposed ROE of 11.00% and 7.353¢ per kWh
9 utilizing Staff's proposed ROE of 9.45%. In developing these estimates, Staff has reflected
10 a 2.6¢ Production Tax Credit per kWh consistent with the recently enacted IRA.
11 Furthermore, Staff's estimate does not incorporate or reflect any maintenance costs
12 associated with the Company's solar facilities.

13 **Q. PLEASE EXPLAIN THE SECOND STUDY STAFF CONDUCTED REGARDING**
14 **A POSSIBLE ALTERNATIVE VALUATION FOR SOLAR ENERGY EXPORTED**
15 **TO THE GRID.**

16 A. The second study Staff conducted is based on the recent net metering compensation method
17 approved by the Michigan Public Service Commission for DTE Energy (formerly Detroit
18 Edison).⁸ The theory behind this analysis is that excess generation supplied to the grid by
19 rooftop solar customers relies on the Company's distribution system to supply its energy
20 to the grid. Therefore, the value (compensation for excess generation) of solar energy
21 supplied to the grid is equal to the cost of generation related and transmission related costs.

⁸ Michigan Public Service Commission, Case No. U-20836.

Staff conducted a study based on the Company's class cost of service study in which the residential direct and indirect distribution costs (rate base and expenses) were subtracted from the total bundled revenues such that the allocated amounts for only generation and transmission were considered. This study resulted in a possible monthly netting compensation rate of 6.99¢ per kWh at current rates. For illustrative purposes, if the Commission authorized half of the Company requested base rate increase this amount would increase to 7.63¢. The details of this study are provided in Staff Exhibit __ BCW-12.

Q. WHY IS IT CORRECT TO INCLUDE THE COST OF TRANSMISSION RELATED COSTS IN THE ABOVE ANALYSIS?

A. Because electricity takes the path of least resistance, any excess generation supplied to the grid will remain within Georgia Power's distribution system. As a result, this supplied energy does not rely upon the Company's transmission system, and can therefore, be thought of as avoiding additional transmission capacity and costs in a long-run concept.

Q. PLEASE PROVIDE A SUMMARY OF THE POSSIBLE RANGES OF RNR CREDITS OR VALUE OF MONTHLY NETTING FOR EXCESS ENERGY SUPPLIED TO THE GRID BY RNR CUSTOMERS.

A. The following provides a range of potential credits or value of monthly netting (on a kWh basis) for excess generation due to residential monthly netting *at current rates*:

Unbundled Generation plus Transmission	6.99¢
GPC Owned Solar Revenue Requirement	7.35¢ to 8.34¢
Full Retail Volumetric Rate	

Non-Summer	9.01¢
Summer	12.94¢
Annual	10.22¢

Q. DOES STAFF RECOMMEND THAT RNR CUSTOMERS AFTER JANUARY 1, 2023 BE REQUIRED TO TAKE SERVICE ON THE TOU-RD RATE?

A. No. Due to its structure, with a high demand charge, and extremely low off-peak energy price, TOU-RD is not well-suited for RNR customers. Under the current TOU-RD rate structure, there are only about 511 on-peak hours in the year and about 8,249 off-peak hours during the year.⁹ First, consider the scenario of the continuation of monthly netting. The customer would only receive a netting value of about 1.0¢ per kWh, less than half of the current solar avoided cost rate of 2.68¢ per kWh during all off-peak daylight hours. Second, consider the scenario of continuing instantaneous netting. During off-peak hours, the customer would pay about 1.0¢ per kWh for delivered energy but receive a netting value of about 2.68¢ per kWh for excess energy supplied to the grid.

Q. IS IT TRUE THAT A CUSTOMER ON RNR WILL PLACE HIGHER DEMANDS ON THE SYSTEM DURING NON-DAYLIGHT HOURS? IF SO, DOES THIS JUSTIFY PUTTING RNR CUSTOMERS ON TOU-RD?

A. While this is true that RNR customers are likely to have a higher demand in non-daylight hours than daylight hours, it is important to understand when this customer's peak demand is likely to occur relative to the system load. As shown in PIA Staff's Direct Testimony of Jamie Barber, Benjamin Deitchman, and Glenn A. Watkins Staff Exhibit __ BDW-12, the

⁹ The on-peak period is the four months of June-September, weekdays excluding holidays for the hours of 2:00 pm-7:00 pm

1 residential class tends to peak between 6:00 p.m. and 7:00 p.m. The system tends to peak
2 between 4:00 p.m. and 5:00 p.m. wherein the system load declines from there. During the
3 summer, there is still significant daylight such that a solar net metering customer will likely
4 peak between 8:00 p.m. and 9:00 p.m. By this time, the system load has declined
5 significantly from its peak that occurred earlier in the evening.

6 **Q. IN ITS SUPPLEMENTAL DIRECT TESTIMONY, DOES THE COMPANY**
7 **OUTLINE OTHER POLICY ISSUES THAT REMAIN UNRESOLVED**
8 **REGARDING CURRENT RNR CUSTOMERS?**

9 A. Yes. The Company poses two questions for the Commission to address. First, the
10 Company asked whether and for how long existing RNR customers should be allowed to
11 remain receiving service and not be on a three-part rate. The second issue is whether and
12 for how long customers on monthly netting should be allowed to receive monthly netting.
13 In its testimony, the Company suggests that the Commission could consider allowing the
14 5,000 monthly netting pilot customers to continue monthly netting for a time period
15 sufficient to recover their investment in their BTM generation system (Supplemental Direct
16 Testimony of Lee Evans and Larry Legg, pg. 15, line 15-18).

17 **Q. REGARDING HOW LONG CURRENT RNR MONTHLY NETTING**
18 **CUSTOMERS SHOULD BE ALLOWED TO REMAIN ON THE SYSTEM**
19 **WITHOUT RECEIVING SERVICE ON A THREE PART RATE, DOES STAFF**
20 **HAVE A RECOMMENDATION?**

21 A. Yes. Staff recommends that neither current or future RNR customers be required to move
22 to a three part or demand based rate.

1 **Q. REGARDING HOW LONG CURRENT RNR MONTHLY NETTING**
2 **CUSTOMERS SHOULD BE ALLOWED TO CONTINUE RECEIVING**
3 **MONTHLY NETTING, DOES STAFF HAVE A POSITION ON THAT ISSUE?**

4 A. Yes. Staff recommends that if the Commission, in this case, does not continue with RNR
5 Monthly Netting, that customers currently receiving monthly netting should be
6 grandfathered and allowed to receive monthly netting for at least 15 years.

7 As stated on Page 63 of NARUC's Distributed Energy Resources RATE DESIGN AND
8 COMPENSATION Manual:

9 The primary argument supporting shielding current DER customers from a
10 change in rates/policy (possibly due to meeting a regulatory or statutory
11 threshold) is that customers desire and expect some level of certainty when
12 making decisions about their individual investments in DER. While
13 individual investment decisions are personal, a regulator should consider
14 whether the policies of the jurisdiction require or desire using rate making
15 as a policy and technology support tool.

16 By grandfathering current RNR Monthly Netting customers for at least 15 years, the
17 extension will allow customers to receive a payback for their solar investment as these
18 customers installed their rooftop solar system with the expectation to be able to continue
19 to receive monthly netting. Without the continuation of monthly netting, these customers
20 would be harmed financially as it will take longer to recover a return on their rooftop solar
21 investment.

22 **Q. DID THE NARUC DER RATE DESIGN AND COMPENSATION MANUAL**
23 **PROVIDE EXAMPLES OF OTHER STATES THAT ALLOWED**
24 **GRANDFATHERING FOR EXISTING ROOFTOP SOLAR CUSTOMERS?**

1 A. Yes. On page 64 of the NARUC DER Rate Design and Compensation Manual, the
2 following examples were provided:

- 3 • California implemented grandfathering for a 20-year period for both NEM 1.0
4 customers and new customers taking service under the NEM 2.0 tariff.
- 5 • Kansas grandfathered customers that began operating a renewable energy resource
6 before July 1, 2014, for 15 years until December 31, 2029.
- 7 • Nevada agreed to a 20-year grandfathering period for customers that had installed or
8 had active applications before December 31, 2015.

9 **Q. YOU PREVIOUSLY MENTIONED THAT THE 0.2% THRESHOLD WOULD BE**
10 **REACHED VERY SOON, WHAT IMPLICATIONS COULD THAT HAVE IF THE**
11 **COMMISSION SETS A CREDIT FOR EXCESS GENERATION AS OPPOSED TO**
12 **CONTINUING MONTHLY NETTING?**

13 A. Unlike monthly netting where the Company is not purchasing the customer's excess
14 generation, the Company's obligation to purchase excess generation may end when the
15 0.2% of the Company's prior year annual peak demand is reached. This could mean that
16 customers who install a rooftop system after the limit is reached would receive no value
17 for their excess energy.

IV. CONSUMER PROTECTIONS

18 **Q. IS STAFF AWARE OF ANY CONSUMER RELATED ISSUES REGARDING THE**
19 **INCREASED INSTALLATION OF ROOFTOP SOLAR IN GEORGIA?**

20 A. Yes. As noted in the Company's Supplemental Direct Testimony of Legg and Evans, p.
21 16 lines 13-15, Staff is aware of a growing segment of dissatisfied solar customers. The
22 Commission has received complaints from customers who are in dispute with their rooftop

1 solar installer as a result of delays, improper installation, or unmet expectations. Staff
2 believes that these issues arise from both unknowledgeable and disreputable installers.

3 Staff is particularly concerned about the increase in inaccurate information that is being
4 provided to customers which gives these customers unrealistic expectations regarding
5 savings associated with the installation of a system or in some cases that the customer will
6 no longer have an electric bill. Specific items of concern that Staff has discussed with
7 customers include: the oversizing of the solar system when compared to the customer's
8 load, overly optimistic payback periods, promises of monthly netting although the program
9 cap had been reached, and the apparent lack of understanding by the solar installer of the
10 Company's rates and how customer bills are calculated.

11 **Q. DID THE COMPANY PROVIDE A PROPOSAL TO ADDRESS THE CONSUMER**
12 **ISSUES RELATING TO ROOFTOP SOLAR?**

13 A. Yes. In its Supplemental Direct Testimony of Witnesses Legg and Evans, the Company
14 proposed the development of a formal framework for Commission referral of consumer
15 complaints to the Consumer Protection Division of the Attorney General's Office.

16 **Q. DO YOU KNOW HOW THIS FORMAL PROCESS WOULD WORK?**

17 A. No. During the recent hearing on the Company's Supplemental Direct Testimony, Witness
18 Legg stated that "we don't have any particular idea of what exactly that would look like.
19 We would be open to meeting with the Commission and Commission Staff to discuss any
20 formalization of that... We want to make sure a robust process is in place for those

1 complaints to be followed up on”. However, Witness Legg did offer that this could include
2 “keeping a tracked list and following up to see what happens with those [complaints]”.

3 **Q. CURRENTLY WHAT HAPPENS WHEN THE COMMISSION RECEIVES A**
4 **COMPLAINT FROM A CONSUMER REGARDING THEIR ROOFTOP SOLAR**
5 **INSTALLATION?**

6 A. Currently, if a complaint is received from a consumer regarding a solar rooftop system and
7 the issue is not directly related to Georgia Power, the customer’s bill or the RNR tariff, the
8 Commission’s Consumer Affairs Staff sends the complaint to the Consumer Protection
9 Division of the Attorney General’s Office.

10 **Q. HOW MANY COMPLAINTS HAS THE COMMISSION RECEIVED FROM**
11 **CONSUMERS WITH ROOFTOP SOLAR SYSTEMS?**

12 A. Complaints from customers that are not directly related to Georgia Power are not entered
13 into the Commission’s database; however, Staff was told by the Consumer Affairs Manager
14 that 24 complaints in total have been referred to the Georgia Attorney General’s Office.

15 **Q. DOES STAFF SUPPORT THE COMPANY’S RECOMMENDATION FOR A**
16 **MORE FORMAL FRAMEWORK OF REFERRING COMPLAINTS TO THE**
17 **ATTORNEY GENERAL’S OFFICE?**

18 A. Staff agrees that a meeting between the Commission, Georgia Power and the Consumer
19 Affairs Division of the Georgia Attorney General’s Office could be beneficial. While the
20 Commission has not been tasked with regulating the rooftop solar industry, it can assist
21 with consumer complaints received by the Commission by ensuring that consumers are

1 provided the appropriate information necessary to file a complaint with the Attorney
2 General's Consumer Affairs Division office. That said, the Commission already refers
3 consumers who contact the Commission to the Consumer Affairs Division of the Georgia
4 Attorney General's Office. So, it may be fruitful for the Staff and the Company to continue
5 to explore additional ways to protect consumers.

6 **Q. DOES THIS COMPLETE YOUR TESTIMONY?**

7 **A. Yes.**

1 MR. THOMAS: And I would ask that Exhibits
2 BCW-1 through BCW-12 be marked for identification
3 purposes as Staff Exhibits 119 through 130.

4 MADAM CHAIR PRIDEMORE: So marked.

5 (The documents referred to were marked for
6 identification as Staff's Exhibits 119 through 130.)

7 MR. THOMAS: Madam Chair, with your permission,
8 the panelists would like to divide their summary into
9 three 5-minute summaries.

10 VICE-CHAIRMAN ECHOLS: You may proceed.

11 MS. BARBER: In the July 29th, 2022, Georgia
12 Power Integrated Resource Plan order, the Commission
13 ordered staff and Georgia Power to address the
14 structure and processing of the renewable and
15 nonrenewable RNR tariff in the company's 2022 rate
16 case.

17 Specifically, the Commission-approved motion
18 directed staff to address the appropriate structure
19 and processing of the RNR-10 tariff in this case so
20 that the Commission can move towards a fair and
21 long-term way of addressing this issue.

22 Our supplemental direct testimony responds to
23 the recommendations provided in the supplemental
24 direct testimony of company witnesses Larry Legg and
25 Lee Evans and Dr. David Gattie.

1 The Georgia Cogeneration and Distributed Act of
2 2001, known as the Cogen Act, requires Georgia Power
3 to purchase excess renewable energy from its
4 customers. The Georgia General Assembly established
5 the Cogen Act to encourage private investment in
6 renewable energy resources, stimulate in-state
7 economic growth, enhance the continued
8 diversification of the state's energy resource mix,
9 and reduce interconnection and administrative costs.

10 The Cogen Act requires service providers to
11 purchase renewable power from facilities with a peak
12 generating capacity of not more than 10-kilowatts for
13 residential and 100 kW for commercial systems.

14 The first RNR tariff was approved by this
15 Commission in August 2002. Customers on the RNR
16 tariff work with either a renewable energy resource
17 or nonrenewable energy resource as defined in the
18 tariff, can use such facilities to offset their usage
19 and sell any excess energy back to the company.

20 The RNR tariff was originally offered with only
21 an instantaneous netting compensation option to
22 satisfy the requirements of the Cogen Act. This
23 option, which is now referred to as RNR instantaneous
24 netting, is available to all eligible customers on a
25 first-come, first-serve basis until the cumulative

1 generating capacity of all renewable resources equal
2 0.2 percent of the company's annual peak demand in
3 the previous year as outlined in the Cogen Act.

4 In the 2019 Georgia Power rate case, the
5 Commission concluded, after approval of a motion by
6 Commissioner Echols, that behind-the-meter netting
7 period for customers receiving service on the RNR
8 tariff should be changed from instantaneous to
9 monthly netting for the first 5,000 rooftop solar
10 ratepayers or until new install capacity reaches 32
11 megawatts, whichever occurs first.

12 Under monthly netting, a customer's usage is
13 netted against generation that is supplied into the
14 grid. Applications for RNR monthly netting reached
15 the 5,000 count in mid 2021. Although, installations
16 for these customers were not completed into the
17 latter half of 2022.

18 At the beginning of 2022, the cumulative
19 generating capacity of RNR instantaneous customers
20 was approximately 2.2 megawatts or 0.014 percent of
21 the company's 2021 peak demand of 16,213 megawatts.

22 However, since the cap for RNR monthly netting
23 was reached in mid 2021, more than 40 megawatts of
24 additional projects have applied for RNR
25 instantaneous netting.

1 If all of these systems proceed to installation
2 and completion, the total capacity of the projects
3 might exceed the 0.2 cumulative generating capacity,
4 as stated in the Cogen Act.

5 Based on this information and the rate of new
6 application, staff suspects that the cumulative
7 generating capacity of RNR instantaneous customers
8 may exceed the 0.2 percent of the company's prior
9 year peak demand very soon.

10 Staff is aware of a segment of dissatisfied
11 solar customers. The Commission has received
12 complaints from customers who are in dispute with a
13 rooftop solar installer as a result to delay improper
14 installations or unmet expectation. Staff believes
15 that these issues arise from both unknowledgeable and
16 disreputable installers.

17 Staff agrees with the company's recommendation
18 that a meeting between the Commission, Georgia Power,
19 and the Consumer Affairs Division of the Georgia
20 Attorney General's Office could be beneficial.

21 While the Commission has not been tasked with
22 regulating the rooftop solar industry, it can assist
23 with consumer complaints received by the Commission
24 by ensuring that consumers are provided the
25 appropriate information necessary to file a complaint

1 with the Attorney General's Consumer Affairs
2 Division's office.

3 With that said, the Commission already refers
4 consumers to contact the Commission to the Consumer
5 Affair's Division of the Georgia Attorney General's
6 office. So it may be fruitful for the staff and the
7 company to continue to explore additional ways to
8 protect customers.

9 MR. WATKINS: Based on the revised analysis,
10 the company's witnesses Evans and Legg claim that
11 there is an average annual cost shifting of \$826 per
12 RNR customer that receives service under the R Rate.

13 However, \$560 of this amount is simply the
14 revenue erosion associated with the customer using
15 less energy due to that customer supplementing its
16 energy needs with rooftop solar. As such, this \$560
17 revenue -- revenue erosion adjustment should not be
18 considered.

19 Within -- with this, Evans and Legg then
20 estimated that the average RNR customer has an
21 additional cost shift of \$287, which reflects the
22 revenue erosion associated with the difference
23 between the customer's annual monthly net -- monthly
24 netting bill and what the customer's annual bill
25 would be under instantaneous netting.

1 When this average so-called cost shift of \$287
2 is multiplied by a population of 5,000 RNR customers,
3 staff has calculated that the reduced revenue is less
4 than 5/100th of one percent of the total residential
5 revenue, excluding fuel, and is, therefore, de
6 minimus.

7 Staff conducted a sample analysis of the 1,102
8 RNR customers using each customer's actual monthly
9 usage during 2021 that included monthly delivered
10 kWh, excessive kWh, and net kWh. With this data,
11 staff determined the average monthly netting
12 customers delivered kilowatt-hours is somewhat larger
13 than the average Rate R customers and that its net
14 kilowatt-hours is somewhat smaller than the average R
15 Rate customer.

16 As a result, the average monthly netting
17 customer's bill is somewhat lower than the average R
18 Rate customer; i.e., \$112.82 cents versus \$127.55.

19 While these customers contribute somewhat less
20 revenue per customer than R Rate customers, it must
21 be remembered that monthly netting customers provide
22 value to the company and all other customers by
23 supplying electric energy to the grid.

24 In order to provide information to the
25 Commission on possible alternatives to value excess

1 energy exported to the grid by RNR customers, staff
2 has conducted various analyses.

3 First, staff determined that under the current
4 monthly netting mechanism, the value per
5 kilowatt-hour that monthly netting customers receive
6 varies depending on whether they are a large customer
7 or a small customer. To illustrate, during the four
8 summer months, a large customer with usage greater
9 than 1,000 kilowatt-hours received a monthly netting
10 value of 15.68 cents per kilowatt-hour, while the
11 smaller customer that uses 650 kilowatt-hours only
12 receives a monthly netting value of 10.36 cents.

13 Similarly, during the eight non-summer months,
14 a large customer using more than 1,000 kilowatt-hours
15 receives a monthly netting value of 9.12 cents, while
16 the smaller customer that uses only 650
17 kilowatt-hours will receive a monthly netting value
18 of 10.29 cents per kilowatt-hour.

19 It is staff's opinion that the value of the
20 kilowatt-hour of excess solar generation supplied to
21 the grid should be the same for both large usage
22 residential customers and small usage residential
23 customers.

24 Based on 2021 usage characteristics, staff has
25 calculated that the current annual weighted average

1 solar value is about 10.22 cents per kilowatt-hour
2 and can be bifurcated between summer and non-summer;
3 wherein, the summer value is about 12.94 cents and
4 the non-summer value is about 9.01 cents.

5 Next, staff calculated the fixed capital cost
6 revenue requirement associated with the company's own
7 solar facilities and determined that ratepayers are
8 paying approximately 8.34 cents per kilowatt-hours,
9 using the company's proposed cost of capital, or
10 about 7.35 cents per kilowatt-hour, using staff's
11 proposed cost of capital.

12 Staff conducted another analysis using a
13 methodology approved by the Michigan Public Service
14 Commission for DTE Energy, formally Detroit Edison.

15 This methodology unbundles revenues such that
16 the residential distribution costs are subtracted
17 from residential revenues. The theory behind this
18 approach is that rooftop solar customers supplying
19 energy into the grid should not be compensated for
20 costs associated with distribution service because
21 these customers rely on the distribution system to
22 supply energy back into the grid.

23 Under current rates, staff has calculated this
24 value is about 6.99 cents per kilowatt-hour. A
25 summary of staff's alternative analyses are provided

1 on pages 29 and 30 of our supplemental testimony.

2 MR. COOK: Staff's recommendations for the
3 rooftop solar compensation rate are based on a
4 consideration of actions that other state commissions
5 have taken. Many states across the country recently
6 began to assess the question of: What is the
7 appropriate compensation for customer generators?

8 These include North Carolina, South Carolina,
9 Florida, Arkansas, Mississippi and Michigan, each of
10 which opened a dedicated docket for litigating their
11 state's net metering policy.

12 It is also important to understand that each of
13 these states, aside from Mississippi, have
14 significantly higher penetration of rooftop solar
15 adoption than what currently exists in Georgia
16 Power's service territory.

17 Georgia Power ranks -- or Georgia ranks 37th
18 for the capacity of behind-the-meter solar installed
19 when you consider only Georgia Power's service
20 territory. For comparison, Arkansas has twice the
21 amount of solar installed and is ranked 34th. And
22 13th ranked Nevada has about ten times as much solar
23 installed.

24 While each state has enacted its own unique
25 policy, there are two distinct policy categories that

1 have been adopted by other state commissions.

2 The first category consists of the continuation
3 of net metering, with the addition of bill
4 mechanisms, such as meeting minimum bills or time of
5 use rates or demand rates mandated.

6 For -- South Carolina is one example that
7 requires future net metering customers to be on a TOU
8 rate and imposes a small minimum bill.

9 Arkansas also uses the structure and there are
10 similar -- there are similar examples from North
11 Carolina, as well.

12 The other category of net metering policy is
13 what is often referred to as an export rate. An
14 export rate is the same mechanism as Georgia Power's
15 instantaneous netting policy; however, other states
16 have set different values for their export rate,
17 other than the avoided costs.

18 Michigan's export rate or outflow, as they
19 refer to it, is based on the retail rate with a
20 portion of costs related to the distribution system
21 removed, as explained by Witness Watkins.

22 Staff identified similar rate structures in
23 several other states, as outlined in our testimony,
24 such as Utah and Mississippi, who employ a
25 cents-per-kilowatt adder. Staff also (inaudible) the

1 Michigan model from DT Energy for one of our
2 compensation rate recommendations.

3 Finally, if the Commission in this case does
4 not continue with RNR monthly netting, the company
5 posed the question of whether and for how long
6 existing RNR customers should be allowed to receive
7 monthly netting to remain receiving service without
8 being on a three-part rate.

9 Staff recommends that neither current nor
10 future RNR consumers be required to move to a
11 three-part or demand-based rate, and that if the
12 Commission in this case does not continue RNR monthly
13 netting, that customers currently receiving monthly
14 netting should be grandfathered and allowed to
15 receive monthly netting for at least 15 years. By
16 grandfathering current customers for at least 15
17 years, the extension will allow customers to receive
18 a payback for their solar investment.

19 This concludes our summary.

20 MR. THOMAS: Thank you.

21 Mr. Chairman, the panel is available for
22 questions from Commissioners and cross-examination.

23 VICE-CHAIRMAN ECHOLS: Commissioners,
24 questions?

25 (No response.)

1 VICE-CHAIRMAN ECHOLS: All right. You going
2 last?
3 MR. HEWITSON: Please.
4 VICE-CHAIRMAN ECHOLS: Okay. Anybody A through
5 E have questions?
6 (No response.)
7 VICE-CHAIRMAN ECHOLS: A through E. We're
8 expediting here. Sorry.
9 Let's start with the Gs then. Anybody in the
10 Gs?
11 Georgia Association of Manufacturers.
12 MR. JONES: No. I was going to say I didn't
13 have any questions.
14 VICE-CHAIRMAN ECHOLS: Anybody else that starts
15 with G?
16 MS. BROWN: The Coalition.
17 VICE-CHAIRMAN ECHOLS: Okay. Let's go with the
18 Coalition.
19 MR. HEWITSON: That starts with C.
20 MS. BROWN: We are Georgia Coalition.
21 VICE-CHAIRMAN ECHOLS: We are having an
22 alphabet problem here. It was math last time; right?
23 MR. HEWITSON: Exactly. Working through the
24 subjects.
25 //

1 CROSS-EXAMINATION

2 BY MS. BROWN:

3 Q Good afternoon, everybody. Alicia Brown on
4 behalf of Georgia Coalition of Local Governments.

5 If I can direct you to page 27 of your
6 testimony, lines 11 through 13. Your testimony states:
7 Staff is of the opinion that the value of excess generation
8 supplied to the grid is the same per kilowatt-hour for both
9 a large customer and for a small usage customer.

10 And then a couple pages later, you provide
11 those three recommended values for the Commission. Just to
12 make sure I'm understanding, is this recommendation to
13 maintain instantaneous netting and change the outport --
14 excuse me -- the export rate above the RCB or is this to
15 maintain monthly netting and this be for net excess
16 generation?

17 A (Witness Cook) It would be a change to the
18 instantaneous rate.

19 Q Okay. Thanks for clarifying.

20 So if we can go to page 28, beginning at the
21 top of the page. This will also include your Exhibit
22 BCW-11. So staff is looking at a new proposal for the
23 outflow rate that's based on the revenue requirement for
24 company-owned solar facilities, which comes to 7.35 to 8.34
25 cents per kilowatt-hour.

1 I first note it because it's higher than the
2 prevailing rate for competitive PPAs. So I was wondering:
3 Is it high because this includes older resources before
4 solar got cheaper or is there like a structural reason?

5 A (Witness Watkins) No idea.

6 A (Witness Cook) I --

7 A (Witness Watkins) It is what it is. It's based
8 on the -- the investment data of the company of what the
9 company's numbers are. That's all I can say.

10 Q Okay.

11 A (Witness Cook) I would add that it does include
12 older generation. A lot of those were built three, five
13 plus years ago.

14 Q Okay. And then on line 19 on page 29, you
15 stress that this is based on current rates. If this
16 framework were carried forward, would you expect that price
17 to go up or down or stay about the same over time?

18 A (Witness Watkins) I think -- no. I think it
19 would depend frankly on, you know, what kind of overall rate
20 increase we have. But because of the way traditional
21 ratemaking is, as time goes on, it would probably go down
22 for the existing solar.

23 But, now, to the extent the company continues
24 to build solar, of course, that will be new investment
25 that's going to cost more. So I really don't have a very

1 good crystal ball, as far as that goes.

2 The plant that's in service today over time,
3 the revenue requirement goes down. But as they build -- if
4 they do build more solar, that's going to have a higher
5 price per kilowatt-hour than embedded or existing plant.

6 Q Okay. That's really helpful.

7 So on page 28, lines 11 and 12, you say that
8 this price does not include operations and maintenance; is
9 that correct?

10 A (Witness Watkins) Correct.

11 Q But don't customers pay for operation and
12 maintenance for company-owned solar utilities?

13 A (Witness Watkins) They do. I just did not want
14 to bias my results with any inaccuracy. Sure, there's some
15 maintenance required for solar. I just don't know what it
16 is. So I didn't want to put in a fictitious number.

17 Q Yeah. I understand. But, just to clarify, if
18 there's customer-owned solar, the broader base of customers
19 would not be required to pay O&M for customer-sided solar;
20 would that be correct?

21 A (Witness Watkins) Would you repeat the
22 question?

23 Q I could rephrase it. It may be a little
24 confusing.

25 If I had solar on my rooftop, would all Georgia

1 Power customers pay for O&M or would I be responsible for
2 O&M?

3 A (Witness Watkins) Obviously, just you.

4 Q Okay. Thank you.

5 So going to page 28 for your second calculation
6 for Michigan.

7 A (Witness Watkins) Did you say 28?

8 Q Yeah. 28.

9 So I just want to make sure I understand that
10 calculation, as well. You're looking at the retail rate and
11 you're subtracting out distribution expenses from the retail
12 rate; is that correct?

13 A (Witness Watkins) Not entirely, but you're
14 getting there.

15 Q Okay. So is it --

16 A (Witness Watkins) May I explain? Maybe this
17 will help you.

18 So we start out with the total bundled rate
19 revenue for the residential class. You know, everything.
20 And then, like in Michigan, we said: I want to take out the
21 costs associated with distribution.

22 So that includes O&M expenses and then
23 depreciation and then, importantly, the return on and of
24 that investment. You know, the rate of return, the profit
25 component, and then the income taxes associated with that.

1 So we're like taking out the revenue
2 requirement associated with distribution, if you will. And
3 in doing so, just so everybody is clear, in our analysis we
4 included both the direct and indirect distribution costs so,
5 you know, we wouldn't be accused of ignoring general plant
6 that is there to serve the distribution function.

7 VICE-CHAIRMAN ECHOLS: Don't feel like you have
8 to add to the testimony. Just answer it.

9 She'll ask if she needs more. This is the
10 lightning round.

11 MS. BROWN: Well, I was actually going to ask
12 about that.

13 BY MS. BROWN:

14 Q Your Exhibit BCW-12 on page 1, is the term
15 indirect distribution in the company's cost of service study
16 or is that something you determined?

17 A (Witness Watkins) It came straight out of the
18 company's cost of service study as shown in the succeeding
19 pages. It shows the detail of that.

20 Q Okay. I didn't find the term, but I may have
21 been looking in the wrong spot.

22 So looking at what's included in that, it
23 includes things like uncollectibles, prepay expenses,
24 informational and instructional expenses. Understanding
25 that billing and customer service is important even for

1 export solar, is it fair to include all administrative and
2 collection-related costs in this calculations?

3 A (Witness Watkins) Let's see what we did here.

4 Q I believe it was page 10 where those expenses
5 were listed on.

6 A (Witness Watkins) Thank you so much.

7 Q Of that exhibit.

8 A (Witness Watkins) Yes, we did. We did subtract
9 those out. You are correct.

10 Q So let me make sure I'm understanding that. Is
11 that included in the 6.99 cents or --

12 A (Witness Watkins) That's what we took out. So
13 that's --

14 A (Witness Barber) Excluded.

15 A (Witness Watkins) Excluded. In other words, we
16 take the total revenue, subtract out the revenue requirement
17 associated with distribution, which includes these line
18 items that we're discussing.

19 Q So let me make absolutely sure I'm
20 understanding. The rate that exported solar would receive
21 would be higher without prepay expenses and uncollectibles
22 and advertising because all of that was considered
23 distribution?

24 A (Witness Watkins) As a matter of arithmetic,
25 you're absolutely right.

1 Q Okay. I just wanted to make sure I was
2 understanding that.

3 And just to get a question: Do you think that
4 that's appropriate to influence the cost or value of
5 exported solar?

6 A (Witness Watkins) Yeah. I mean, it's -- I
7 don't want to bicker over it. It's not that much money.

8 Yeah, one could argue, yeah, maybe some of the
9 uncollectibles. It's not going to change it a mill. So I
10 didn't want to get into arguments with people: Oh, this
11 should be included.

12 It's not that important. You know, if it makes
13 you feel better, take it out. It's not going to change the
14 answer.

15 Q Okay. And looking at direction distribution
16 costs, specifically page 4 of your exhibit --

17 A (Witness Watkins) I'm there.

18 Q I'm curious about the inclusion of what you're
19 calling transmission substations or step-down substations.
20 Am I correct that this was focused on residential rates?

21 A (Witness Watkins) That's correct.

22 Q So in the case of residential solar, how likely
23 is it that I'm going to back feed all the way to a
24 transmission level substation?

25 A (Witness Watkins) Well, it's the load -- it's

1 the load voltage substations. So perhaps it wouldn't. And,
2 you know, if -- if you took that out, the rate might be a
3 little bit higher.

4 And, again, remember that the 6.99 is based on
5 current rates. You know, if we have a rate increase,
6 this -- these allocated costs are going to go up a little
7 bit, so...

8 MS. BROWN: Okay. Thank you.

9 VICE-CHAIRMAN ECHOLS: Thank you, ma'am.

10 Anyone else start with the letter G?

11 GA Solar.

12 (No response.)

13 VICE-CHAIRMAN ECHOLS: GASEIA and Solar Energy
14 Industries.

15 Thank you, Commissioner.

16 CROSS-EXAMINATION

17 BY MR. THOMASSON:

18 Q I'll pick up where she left off. She was
19 asking sort of about some of the -- what you were backing
20 out from that total revenue.

21 My question is actually about the total revenue
22 starting point. In your exhibits, which I don't think you
23 need to turn to for this question, your starting point is --
24 you describe as base rate revenue; is that correct?

25 A (Witness Watkins) Correct.

1 Q Does that include other revenue sources that
2 are on the customer's bill, like ECCR and NCCR?

3 A (Witness Watkins) I believe it does include the
4 EECR. It does not include the NCCR.

5 I apologize. I've done three cases since I sat
6 on the witness stand on my cost of service study. So it's
7 whatever was in the company's cost of service study.

8 Q I mean, I guess I could just ask -- you don't
9 have to remember whether it's in there. But would it be
10 appropriate -- is there a reason to exclude any of those
11 other revenue components that aren't necessarily base rate?

12 I mean, if they feed into the generation rate
13 -- I mean, I'm being granular like she was on the backout,
14 but --

15 A (Witness Watkins) No. I think I understand
16 your question. And that's a very good question. And
17 perhaps we should have discussed this a little bit in our
18 testimony.

19 The public witness today that discussed, you
20 know, being exempt from ECCR because of rooftop solar, he
21 makes a very good point. But, in my opinion, the way that
22 the monthly netting works now is the customers that -- when
23 they net meter they get the benefit of reducing the
24 responsibility for NCCR, ECCR and DSM.

25 And I don't want to say there's a right or

1 wrong way to do it, but it would seem to me that the
2 intention of recovery of ECCR costs is based on what the
3 company provides for delivered service.

4 Because when you're selling power back into the
5 grid, that's a different service. You're becoming a seller,
6 if you will. That's my opinion.

7 So perhaps we should have mentioned that a
8 little bit. But I think that would help things a little
9 bit. That would tend to lower the compensation rate for
10 net -- monthly netting a little bit.

11 But in my understanding -- and Mr. Cook and
12 Ms. Barber may disagree with that. I think the intention of
13 these riders are to recover costs that are as a result of
14 delivering power to the company -- to the customers.

15 Q Okay. Just to clarify, when we're talking
16 about the numbers you've calculated, especially the Michigan
17 model, which I'm mostly referring to here, that's not a
18 monthly netting model. That's more of what we refer to as
19 an export model and they refer to as outflow; right?

20 A (Witness Watkins) Absolutely. Yes.

21 Q So it doesn't really work the same anyway.
22 Could you do the same calculation for a monthly netting
23 credit that sort of starts with the overall revenue or is
24 that exclusive?

25 A (Witness Watkins) Yeah. No. You're correct.

1 It -- you don't have that problem if you use an export rate
2 concept, if that makes sense.

3 Q Yeah. Just sort of confirming that that's --

4 A (Witness Watkins) Yes.

5 Q All right. Well, let's go back to the other
6 states' policies that you've looked at. I mean, you
7 mentioned on page 12 that other states have -- you know,
8 reformed net metering by adding minimum bills, mandatory TOU
9 and demand rates in some cases.

10 Is it the case from the states you reviewed --
11 the states that had those specific components are also
12 retaining that netting -- that full retail netting component
13 and, you know, putting a different lever on it with these
14 other bill components?

15 A (Witness Cook) Yeah. And I think to the point
16 of the testimony, the option of adding those minimum bills
17 and those other components was typically done in concert
18 with retaining net metering. And, also, I would note that
19 that analysis is looking at states that diverged from just
20 keeping net metering. There were also states that
21 maintained net meeting without even integrating those time
22 of use or minimum bills.

23 Q That's an important point. And that goes back
24 to the two categories that you've testified to in your
25 summary. So it's kind of either/or. You either add these

1 other demand rates and other bill components and keep net
2 metering or you monkey with the rate a little bit and maybe
3 lower the rate or use a Michigan-style export rate, but you
4 don't double up and do both typically?

5 A (Witness Cook) That seems to be the case.

6 Q Okay. In your view of other states, has there
7 also typically been an inclusion of some sort of
8 grandfathering provision for existing net metering
9 customers?

10 I know you talk about sort of the NARUC
11 recommendations on grandfathering, but did you see that play
12 out in the recent state policy changes?

13 A (Witness Cook) I didn't specifically look at
14 that, but I would say that fairly universally there is
15 grandfathering of existing customers.

16 A (Witness Barber) Yeah. I will add to that.
17 Yes, generally you do see grandfathering of existing net
18 metering customers, if the Commission does change their
19 policy.

20 We did list three states. I know there's
21 others. Most of them are generally 20 years of
22 grandfathering.

23 Q Okay. That was actually going to be my
24 question. Because you mentioned the 15 year NARUC --

25 A (Witness Barber) Well, there was two. I think

1 there was two that were 20 and one was 15. But generally,
2 at least 15, but most are 20.

3 Q But we've seen 20 pretty commonly?

4 A (Witness Barber) Yeah.

5 Q Okay. You got there faster than I would have.
6 Thank you.

7 Well, let's talk about TOU-RD, which we've
8 covered a lot already. On page 30 of your testimony, you
9 recommend that the Commission not approve mandatory TOU-RD
10 for RNR customers; is that correct?

11 A (Witness Cook) Correct.

12 Q Among those reasons -- the reasons for that,
13 you say that the structure for the on-peak and off-peak
14 pricing is not a good fit for solar customers.

15 Is that a fair summary?

16 A (Witness Watkins) Yes.

17 Q Can you explain a little bit why it's a bad
18 fit, in terms of that particular time of use structure?

19 A (Witness Watkins) Yes. Well, on page 30 that
20 we're referring to, on the lines 1 through 11, you can see
21 that under the current structure of the TOU-RD rate, you get
22 sort of conflicting benefits, if you will.

23 But as important is the actual makeup of the R
24 TOU-RD rate. With respect to TOU-RD rate, only
25 18.37 percent of the customer's base bill is based on

1 energy. The remaining -- whatever that is, 72 percent -- is
2 based on the demand charge.

3 So this -- the demand charge that they
4 currently have of -- what is it -- \$8 and change -- I will
5 find it here. Whatever it is. \$8.21, it's the highest
6 residential demand charge I've seen anywhere.

7 I mean, it's -- it's by far the largest I've
8 seen anywhere and I've practiced all over the country. I
9 don't know how they came up with it, but it is what it is.

10 But just look at common sense. The off-peak
11 kWh charge is only a penny. That's less than your fuel
12 cost. And the on-peak charge is 9 cents. It just does not
13 fit well at all for -- for solar.

14 Q Would it be fair to say that an average RNR
15 customer that's on instantaneous netting now would probably
16 see lower compensation if they were switched to a mandatory
17 TOU-RD?

18 A (Witness Watkins) Oh, beyond a doubt.

19 Q Okay. Let's talk about revenue erosion. On
20 page 15 and 16 you talk about the company's analysis in this
21 proceeding. And you ultimately recommend that the
22 Commission not consider the company's analysis because it's
23 based on revenue erosion. And that's not appropriate for
24 this case; is that an accurate summary?

25 A (Witness Watkins) Not exactly. The

1 Commission's order asked us to look at two things. That is,
2 you know, a cost analysis -- what is the cost analysis and
3 what is the impact on customers?

4 As we indicate in our testimony, the company
5 did not conduct a cost analysis of serving solar customers,
6 but -- to some degree, they did conduct an analysis of the
7 impact of existing -- of other nonsolar customers.

8 However, we disagree with portions of what the
9 company's analysis is on the impact of existing nonsolar
10 customers in that the \$560 is simply revenue erosion from
11 anybody putting a solar panel up or not, whether they decide
12 to engage in net metering or not. I think there's validity
13 in the -- what it -- \$287.

14 Is that what it is?

15 Q I think that's right.

16 A (Witness Barber) Yes.

17 A (Witness Watkins) 287.

18 Q 284?

19 A (Witness Watkins) Yeah. So I don't know if
20 that helps you or not.

21 Q Well, let me ask you this. Do you agree with
22 the company's testimony that a cost of service study
23 specifically for RNR customers is not appropriate because
24 cost of service lacks surgical precision to analyze those
25 customers?

1 A (Witness Watkins) Yeah. I disagree with their
2 assertions. You know, an analysis -- with the great data
3 that Georgia Power has or should have -- and when I say
4 that, right now they're not really monitoring the demands of
5 non-demand residential customers. Or at least they're not
6 keeping all of those records.

7 But with the technology we have, it certainly
8 could be done on both an embedded or a marginal basis. In
9 fact, I'm aware of a very, very good study -- not that I
10 agreed with everything in it, but a very detailed study
11 conducted in South Carolina for Duke.

12 I think there was differences of opinion on
13 what you should do and how should do it, just like in any
14 cost allocation or cost of service study. But in South
15 Carolina, they did it both on a marginal and an embedded
16 basis.

17 And if you have 5,000 customers, you're getting
18 a pretty good idea of what's going on. Remember, in their
19 analysis they collapse everything down to 1,110 customers
20 and said that's a reasonable sample size.

21 If you have data for 5,000 customers, of course
22 you're going to have to throw out some outliers. But that's
23 the art of knowing what you're doing.

24 Q So would you say then that -- you think it's
25 possible the company could have provided a cost of service

1 analysis for RNR customers in this proceeding?

2 A (Witness Watkins) Some form of cost of service,
3 yes.

4 Q Okay. And then one question that may be for
5 all of you that's related to revenue erosion. In looking at
6 other states, have you seen examples of other states that
7 recognize revenue erosion as a justification for cost shift
8 and for cost recovery and --

9 A (Witness Watkins) I do know that Arizona --
10 Arizona Public Service was concerned about that. But,
11 remember, that's Arizona. This is Georgia.

12 Q That's Arizona. But -- Mr. Cook, do you
13 have --

14 A (Witness Cook) I wouldn't say that I have seen
15 that specific line of thought and reasoning going from the
16 revenue erosion to implying that's a cost shift to
17 justifying policy based on that.

18 Q Is it fair to say that's not typically what the
19 cost shift debate looks like in other states?

20 A (Witness Cook) I guess I would say that that
21 isn't what I had seen.

22 Q Okay. Quick question on the IRA. On page 11,
23 you mentioned Georgia Power's witnesses testified that the
24 IRA is a reason not to expand monthly netting because it's a
25 stimulus to the solar market in Georgia. And you disagreed

1 with that.

2 Is that a correct summary of your testimony?

3 A (Witness Barber) Yes.

4 Q Is it fair to conclude from that disagreement
5 that the ITC and the other -- and the incentives in the IRA
6 that aren't entirely new to the Georgia market aren't going
7 to -- even though they've been extended, they're not going
8 to create, like, a huge new wave of demand for residential
9 customers in Georgia that would justify that?

10 A (Witness Barber) Yes. We agree with that.

11 MR. THOMASSON: Okay. I think that's all I
12 have.

13 MADAM CHAIR PRIDEMORE: Interstate Gas Supply.
14 They are done for the day, I believe.

15 Kroger. Did he return?

16 (No response.)

17 MADAM CHAIR PRIDEMORE: Okay. That's two. I'd
18 say he's done.

19 MARTA.

20 MS. STURM: No questions.

21 MADAM CHAIR PRIDEMORE: Resource Supply
22 Management.

23 (No response.)

24 MADAM CHAIR PRIDEMORE: Resource Supply
25 Management, Mr. Clarkson.

1 (No response.)

2 MADAM CHAIR PRIDEMORE: We'll mark him done, as

3 well.

4 Sierra Club.

5 MS. ARIZA: No questions.

6 MADAM CHAIR PRIDEMORE: SACE and Southface.

7 MR. DOWDY: No questions.

8 MADAM CHAIR PRIDEMORE: U.S. DOE. I saw

9 Ms. Medlyn pick up her things. Maybe she's done.

10 Ms. Medlyn?

11 (No response.)

12 MADAM CHAIR PRIDEMORE: I'll mark her done for

13 the day.

14 Georgia Watch is done for the day.

15 Redirect.

16 MR. HEWITSON: Is it okay if I cross him?

17 MADAM CHAIR PRIDEMORE: Yes.

18 CROSS-EXAMINATION

19 BY MR. HEWITSON:

20 Q I guess it's now good evening, panel.

21 A (Witness Watkins) Good evening.

22 A (Witness Cook) Evening.

23 A (Witness Barber) Good evening.

24 Q All right. On page 11, line 18 to page 12,

25 line 5, you discuss other states that have recently

1 addressed compensation issues for behind-the-meter solar and
2 you've gotten a couple of questions on this. I won't replot
3 that territory.

4 But since you reference them in the testimony,
5 I assume you're generally familiar with these proceedings.
6 And, I think, Mr. Cook, you've already answered a few
7 questions on it; right?

8 A (Witness Cook) Yes.

9 Q Okay. Would you agree, then, that the
10 Commission proceedings in several of those states were --
11 was initiated based on state legislation or directives that
12 directed the commission to eliminate net metering all
13 together or address the cost shift that occurs with net
14 metering?

15 A (Witness Cook) Agreed in that we don't have a
16 state legislation doing so.

17 Q Well, and that -- that's a fine clarification.
18 But, for instance, in South Carolina and in North Carolina
19 there was legislation that specifically directed the
20 commission to institute a -- to institute a net metering
21 policy and/or rate that addressed the cost shift to
22 nonparticipants; right?

23 A (Witness Cook) Uh-huh.

24 Q Okay. And based on your review of the policies
25 in these other states, do you agree that those legislatures

1 and commissions determined that net metering created a cost
2 shifting problem that needed to be fixed?

3 A (Witness Cook) Yes. Each of them found
4 slightly different things. But, yes, the -- that -- the
5 cost shift was certainly an element in each of those
6 discussions, yes.

7 Q Okay. And as you point out on page 12, lines 3
8 to 5, all but one of these states that you looked at, or at
9 least that you reference in your testimony, I should say,
10 have higher penetration of rooftop solar than Georgia Power
11 currently has; right?

12 A (Witness Cook) Yes.

13 Q Okay. And so maybe we could take the lessons
14 learned from those states and prevent a similar problem from
15 occurring here in Georgia; right?

16 A (Witness Cook) Certainly.

17 Q Okay. And the Commission has a history of
18 taking a measured approach to renewable development so that
19 all customers continue to benefit from it; right?

20 A (Witness Cook) Yes, that's been our approach.

21 Q Okay. And I imagine you would agree with me
22 that if this Commission has an opportunity to prevent a
23 problem from occurring, it would be advisable to do so as
24 soon as possible. Would you agree with that?

25 A (Witness Cook) Yes. I think where our

1 disagreement -- our testimony is -- is identifying that
2 problem and disagreeing with the source and solutions to it.

3 Q On page 14, lines 1 through 6, you begin your
4 discussion of monthly netting by noting that, in your
5 opinion, Georgia Power's supplemental filing did not provide
6 relevant cost information necessary to set just and
7 reasonable rates, terms, and conditions for rooftop solar.

8 Do you see that in the testimony?

9 A (Witness Cook) Uh-huh, yes.

10 Q Okay. And you're quoting Commissioner Shaw's
11 motion in the IRP right there; right?

12 A (Witness Watkins) Correct.

13 Q Okay. And the full sentence of Commissioner
14 Shaw's motion was that in this IRP we simply do not have the
15 cost information necessary to set just and reasonable rates,
16 terms, and conditions for rooftop solar; right?

17 A (Witness Watkins) Okay.

18 Q And Commissioner Shaw can correct me if I'm
19 wrong, of course, but his point was that we shouldn't try to
20 make a decision on net metering in the IRP because the
21 necessary information is not included in that proceeding;
22 right?

23 A (Witness Watkins) That's my understanding.

24 Q Okay. And Commissioner Shaw -- Commissioner
25 Shaw's motion was that staff and the company should each

1 address the appropriate structure and pricing of the RNR
2 tariff in this proceeding, which I think, Mr. Watkins, you
3 said earlier in response to a question?

4 A (Witness Watkins) Correct.

5 Q Okay. And his -- well, would you agree that
6 Georgia Power has provided a lot of cost information in the
7 rate case, including its full cost of service study, which
8 was about 800 pages?

9 A (Witness Watkins) Yeah. But they had nothing
10 to do with net metering.

11 Q Okay. Well --

12 A (Witness Watkins) Not a thing.

13 Q PIA staff put -- Public Interest Advocacy Staff
14 also asked several data requests related to not only the
15 cost of service study, but you also asked a number of data
16 requests specifically related to net metering; right?

17 A (Witness Watkins) Correct. Well into the case,
18 that's correct.

19 Q All right. And PIA staff did not at any time
20 inform the company that it believed the company had failed
21 in any way to respond to those data requests in a complete
22 manner, did it?

23 A (Witness Watkins) That I don't know.

24 Q Ms. Barber? Mr. Cook?

25 A (Witness Cook) No. But I would -- I would note

1 that quite a lot of those data request responses were the
2 company did not do that analysis, or the company cannot --
3 just doesn't have that data.

4 Q Okay. Fair enough.

5 But the point being, staff didn't ever look at
6 the company's responses and say: You have not provided a
7 response to this that we think you should be able to
8 provide?

9 A (Witness Watkins) Wait, wait, wait. Wait a
10 minute. Wait a minute.

11 This thing is so abbreviated. By the time we
12 got responses, I'm down here testifying. We don't get
13 responses until after that.

14 What do we have; two days to evaluate it?

15 Q I understand it's a compressed time schedule,
16 but that's not really the company's fault, is it?

17 A (Witness Watkins) Wait a minute. What are we
18 doing? Pointing fingers here?

19 I'm not your babysitter. I'm not the company's
20 babysitter. You were directed to do a cost study and you
21 didn't do one. It's that simple.

22 Pointing fingers at staff is ridiculous.

23 Q Where was the company directed to perform a
24 cost study?

25 A (Witness Watkins) Well, we certainly did one.

1 I don't know why you couldn't.

2 Q That's not my question. Where were we directed
3 to do one?

4 A (Witness Watkins) I'm not going to argue with a
5 lawyer. I think it was pretty clear. We had the message
6 from the Commission what they wanted. I'm sorry that you
7 didn't. And you guys are pretty intelligent people.

8 Q Thank you.

9 All right. Your testimony does not recommend
10 that the monthly netting pilot be expanded; right?

11 A (Witness Barber) We're not opposed to it. We
12 state it's a policy decision, that that is an option.

13 Q Okay. Your testimony does not recommend; it
14 does not provide a recommendation?

15 A (Witness Barber) It does not specifically
16 recommend it, but it also does not say that we are not
17 supportive of it.

18 Q Okay.

19 A (Witness Watkins) What we're trying to do,
20 Counselor, is to provide alternative options. The status
21 quo can be maintained, whether it be monthly netting or
22 instantaneous. But what we're trying to do is provide
23 information to the Commission on all the possible
24 alternatives.

25 Q Right. And that's the compensation for the

1 export energy that you talk about in your testimony?

2 A (Witness Watkins) That's correct.

3 Q Okay. And before I want to get into that
4 analysis, I want to discuss the heat pump example that you
5 have on page 16, lines 5 to 7 of your testimony.

6 And here you analogize the impact of rooftop
7 solar to a customer installing a more efficient heat pump;
8 right?

9 A (Witness Watkins) I believe that's correct,
10 yes.

11 Q Okay. Do you agree that there is a difference
12 between a permanent reduction in load from energy efficiency
13 measures and intermittent self-generation that simply masks
14 underlying load?

15 A (Witness Watkins) Could you repeat the
16 question, please?

17 Q Sure.

18 Do you agree that there is a difference between
19 a permanent reduction in load from energy efficiency
20 measures and intermittent self-generation that simply masks
21 the underlying load?

22 A (Witness Watkins) Well, I don't know if it
23 necessarily masks the underlying load, but -- I'll put it
24 this way. I had four kids. All four of them were in
25 college at one time. My electric bill went down for four

1 years.

2 When they got out of college, it went right
3 back up because they moved back in the house. So I don't
4 know if it's permanent or not. So you can -- you can take
5 it both ways.

6 Q Let me ask it this way: When a customer
7 installs solar panels on their house, they are not reducing
8 how much electricity they use; they are simply
9 self-producing some of what they need?

10 A (Witness Watkins) Generally speaking, all
11 that's constant, I would agree with that.

12 Q Okay. When a heat pump stops working, the
13 customer's need for electricity from the grid is reduced
14 because that energy-consuming piece of equipment is no
15 longer working; right?

16 A (Witness Watkins) Correct. Presumably they're
17 going to fix it or they're going to be rather chilly.

18 Q On the other hand, when a customer's inverter
19 on their solar panels go out, that doesn't mean that they
20 are using less electricity in their house; right?

21 A (Witness Watkins) No. That's true.

22 Q Okay. It just means that they are no longer
23 self-generating?

24 A (Witness Watkins) Correct.

25 A (Witness Cook) I would counter the point on the

1 heat pump that if it breaks, they can break in such a way
2 that the -- say, most of those heat pumps use a resistive
3 heating element. So it's possible that it would actually
4 break and use more energy using the resistive heating
5 element because the heat pump is broke. So it is possible
6 that that example does go both ways.

7 Q Okay. But in the situation with the solar
8 panels, they still need to get all of their elec- -- if
9 their solar panels break, they need to get all of their
10 electricity from the grid because they're no longer
11 self-producing; right?

12 A (Witness Watkins) Yes.

13 Q And the company must be prepared to reliably
14 serve those needs; right?

15 A (Witness Watkins) Correct.

16 Q And to be prepared to serve the needs, the
17 company must have its transmission, its distribution and
18 generation facilities available and operating; right?

19 Do we agree with that?

20 A (Witness Watkins) Yeah. To serve all customers
21 collectively, not just that one solar customer, correct.

22 Q Do you agree that the residential R Rate is
23 designed to recover more than just the marginal cost of
24 energy delivered to the customer?

25 A (Witness Watkins) Yes.

1 Q By design, the R Rate includes recovery of
2 transmission, distribution, generation and customer-related
3 costs; right?

4 A (Witness Watkins) Correct.

5 Q And the basic service charge, which is
6 currently about \$14 under the R Rate, it does not cover all
7 of the transmission, distribution, or generation costs for
8 each customer, does it?

9 A (Witness Watkins) Nor should it.

10 Q Okay. In fact, it doesn't cover all of the
11 customer-related costs according to the cost of service
12 study?

13 A (Witness Watkins) That -- I disagree with that.
14 You obviously don't remember my testimony on that. It does.
15 It more than recovers it. We have a conceptual
16 disagreement, as far as that goes.

17 Q Okay. So maybe I should word it: It does not
18 cover all the customer-related costs according to the
19 company's cost of service study; right?

20 A (Witness Watkins) I refuse to acknowledge that
21 aspect because I disagree with it wholeheartedly. They've
22 dumped all kinds of stuff. I mean, that's what Professor
23 Bob Bryce says. You know, the utilities like to use
24 customer costs as a dumping ground for all these other
25 costs. And that's exactly what your study is.

1 But I thought we were talking about net
2 metering here.

3 Q We are.

4 The way monthly netting works is that customer
5 generators can net out electricity purchases from the
6 company as if they self-consumed their own generation;
7 right?

8 A (Witness Watkins) Read that back. I apologize.

9 Q The way monthly netting works is that customer
10 generators can net out electricity purchases from the
11 company as if they self-consumed their own generation?

12 A (Witness Watkins) As if they self-consume --

13 A (Witness Barber) Yes.

14 A (Witness Watkins) Yes.

15 A (Witness Cook) Yes.

16 A (Witness Barber) They net, yes.

17 A (Witness Watkins) Yeah, they net it.

18 Q All right. So when customers on the R Rate net
19 out purchases, they are not paying the transmission or the
20 distribution or the generation costs that are designed to be
21 recovered through the volumetric rate; right?

22 A (Witness Watkins) No. That's where you're
23 entirely wrong. And that's where the company's rebuttal
24 testimony mischaracterizes exactly what happens.

25 What's happening is the customer is paying for

1 all of the delivered energy that he has and then he's being
2 compensated for the energy that he pumps back into the grid.

3 Let me give you an analogy.

4 Q Before you do, let's make sure you understand
5 the question. I'm talking a monthly netting customer.

6 A (Witness Watkins) Yes.

7 Q Okay.

8 A (Witness Watkins) Correct.

9 Q And you're telling me that the monthly netting
10 customer pays for all of the delivered energy?

11 A (Witness Watkins) Correct.

12 Q Okay.

13 A (Witness Watkins) Let me -- may I finish?

14 Q Yeah. Absolutely.

15 A (Witness Watkins) Okay. So there's two
16 components. And there's two services. The customer is a
17 customer and then effectively he's a seller.

18 So the analogy is suppose I own a produce stand
19 and I buy my eggs from a -- from the chicken man and then he
20 buys his produce from me. According to your analogy, I'm
21 getting my eggs for free. They're two different products.

22 And, in fact, when you record your revenue and
23 your kilowatt hours, you credit revenue based on your
24 delivered kWh and you debit the netted amount to fuel the
25 costs that you recover. It -- you're trying to portray

1 that -- the aspect that the customer is getting energy for
2 free. No. They're paying for the delivered portion and
3 then they're being compensated for what's being delivered
4 back into the system.

5 Now, the \$64 question is: Is the amount that
6 he's being compensated for too high, too low, or just right?

7 And your position is under net metering, it's
8 too high. But that's a totally different service. He's
9 being a seller at that point.

10 Q And just to make sure I'm clear, you think that
11 that's the construct under monthly netting?

12 A (Witness Watkins) I'm well aware of it. You
13 know, please refer to staff PIA 4-1 or 2 in which I ask
14 about how you book your kilowatt-hours. I mean, that's
15 simple accounting.

16 Q Okay. Well, then let's look at it this way.
17 Let's look at Table 3 of your testimony. And in that table,
18 staff's analysis revealed that 11 percent of monthly netting
19 bills in 2021 --

20 A (Witness Watkins) Slow down a little bit.
21 We're not that -- we're not that smart.

22 Table 3?

23 A (Witness Barber) What page?

24 A (Witness Cook) 24.

25 Q Page 24.

1 A (Witness Watkins) Okay. I'm there. Thank you.

2 Q All right. Staff's analysis revealed that
3 11 percent of monthly netting bills in 2021 resulted in
4 bills with net kilowatt-hour usage less than or equal to
5 zero; right?

6 A (Witness Watkins) That's correct.

7 Q Okay. Have you had a chance to review the
8 company's response to GIPL's hearing request that was filed?

9 A (Witness Watkins) Actually, I did, yeah. Just
10 yesterday.

11 A (Witness Barber) Yesterday.

12 A (Witness Watkins) Yeah.

13 Q Exactly.

14 And that information showed that for the first
15 10 months of 2022, nearly 21 percent of bills for monthly
16 netting customers that are on the R Rate had net zero --
17 zero net kilowatt-hours for the billing period; right?

18 A (Witness Watkins) Yes. And I'll confirm the
19 calculations are accurate. I looked at their spreadsheet.

20 Q If we look at your Table 4 on page 25, you show
21 the number of RNR bills with months of negative net
22 kilowatt-hours for the billing period; right?

23 A (Witness Watkins) Correct.

24 Q And your point here, according to your
25 testimony on page 25, lines 1 through 3, is that almost 80

1 percent of the monthly netting customers had two or fewer
2 months of zero or negative net kilowatt-hour bills during
3 2021; right?

4 A (Witness Watkins) Correct.

5 Q Okay. But if I look at your analysis another
6 way, what Table 4 tells me is that 40 percent of RNR
7 customers had at least one month in 2021 where their monthly
8 bill showed zero or negative kilowatt-hour usage for at
9 least that month; right?

10 A (Witness Watkins) Correct.

11 Q When a customer has a monthly bill of zero or
12 negative kilowatt-hour usage, they pay only the basic
13 service charge for that month, plus the riders calculated,
14 but only on the basic service charge; right?

15 A (Witness Watkins) That would be correct.

16 You're -- you're talking cash versus what's
17 really happening here. They're paying for what was
18 delivered and then they're being compensated for what they
19 sell back into it.

20 On the one hand, he's a buyer; on the other
21 hand, he's a seller. But they're two different things. But
22 you're saying that he is not paying his fair share.

23 He's paying his fair share. The question is:
24 Is he being compensated too much? You would argue he is.

25 Q Okay. Having zero or negative net

1 kilowatt-hour usage for the month doesn't mean the customer
2 did not use electricity, as you're saying; right?

3 A (Witness Watkins) Correct.

4 Q They still have delivered electricity to meet
5 all of their needs?

6 A (Witness Watkins) Correct.

7 Q They relied on Georgia Power's generation
8 facilities for the electricity during the month, didn't
9 they?

10 A (Witness Watkins) Yes.

11 Q Okay. And they relied on Georgia Power's
12 transmission and distribution facilities to get electricity
13 to their house that month; right?

14 A (Witness Watkins) They have.

15 Q And, in fact, to export energy, they use the
16 distribution system going back the other way; right?

17 A (Witness Watkins) Absolutely.

18 Q Okay. Having a zero kilowatt-hour usage month
19 doesn't mean that the customer did not rely on Georgia
20 Power's billing system or customer service system or website
21 or repair service; right?

22 A (Witness Watkins) I would agree with that.

23 Q Okay. Yet, when a customer has a zero
24 kilowatt-hour bill for the month, they do not pay for any
25 transmission or generation services in that month?

1 A (Witness Watkins) How many times do I have to
2 answer that? I said yes. He has paid for everything that
3 is delivered, but then he's being compensated at the net
4 amount.

5 Now, the question is: Is the amount of
6 compensation on the monthly netting compensating him too
7 much? That's really what we're trying to find out. You're
8 --

9 Q Maybe I'm just --

10 A (Witness Watkins) You're trying to make the
11 point -- you're trying to say that these customers aren't
12 paying for anything. They're paying their full share.

13 The question is: Are they being compensated
14 too much for what they're pumping back into the grid?

15 Q Mr. Watkins, if you pay zero in a month, how
16 are you paying your fair share?

17 Are you saying their fair share in that month
18 is zero?

19 Is that your testimony?

20 A (Witness Watkins) I -- I'm tired of arguing
21 with you. If -- I -- I've tried --

22 Q Then don't.

23 A (Witness Watkins) I've tried to explain the
24 accounting and I've tried to explain the difference between
25 being a purchaser and a buyer. The only question before us,

1 as I understand it right now, is: What should the -- as a
2 seller, for lack of a better word, what should the
3 compensation rate be for when you sell excess energy back
4 into the grid? It's that simple.

5 But you're like -- you're trying to show that:
6 Oh, some of these customers aren't paying a penny for using
7 our system.

8 The heck they're not. They're paying their --
9 just like everybody else. It's just that they're being
10 compensated for what the benefit of they're selling back
11 into the system.

12 And I am not recommending a specific number.
13 I'm trying to give options to the Commission on what they
14 may be for that value of what they're selling back into the
15 grid.

16 Q Okay. So -- and just help me out here. I know
17 you don't want to argue with me. If the customer has a
18 zero-kilowatt-hour-usage bill and they pay \$14 in that
19 month, is it your testimony that that \$14, plus whatever the
20 percentage is that -- on the riders, if your -- is it your
21 testimony that that \$14 pays for their entire month's usage
22 of the T and the D and the G systems?

23 A (Witness Watkins) It reflects the amount -- he
24 paid for the amount that was deliv- -- that was deliv- --
25 his delivered kilowatt-hours. Again, what the company does

1 even from an accounting standpoint, they credit revenues
2 based on the delivered amount; they debit fuel expenses for
3 the amount that they sell into the system. It's clear as
4 day.

5 Q And the amount under monthly netting that
6 they're getting credited is at the full retail rate?

7 A (Witness Watkins) Correct.

8 Q Okay.

9 A (Witness Watkins) Plus -- plus, as -- as I --
10 as I discussed earlier, plus the effect of the various
11 riders. They get benefit of that, too.

12 Q Which I think your testimony earlier was you're
13 not sure that they should get the benefit of the rider?

14 A (Witness Watkins) That's my opinion. I -- I
15 think that going a little bit overboard myself.

16 Q Okay. And beginning on page 26, you discuss
17 the value of exported energy and that leads into your
18 discussion of what you think the value should be, or at
19 least the options that you're giving to the Commission to
20 review; right?

21 A (Witness Watkins) Correct. We're not giving
22 specific recommendations. Just options, possible
23 alternatives.

24 Q It's an attempt, though, to -- to determine a
25 proxy for the value of exported energy?

1 A (Witness Watkins) It is.

2 Q All right. There is, however, a valuation
3 methodology for the value of exported energy that has been
4 approved by this Commission already; right?

5 A (Witness Barber) Yes. And we're aware of that.

6 Q Is Mr. Watkins aware of the RCB framework?

7 A (Witness Watkins) I'm -- yes and no. I'm aware
8 that the avoided solar cost rate is 2.2, 2.3 cents, which is
9 -- there's obviously no capacity associated -- cost
10 associated with solar and that it's basically just the fuel.

11 Q Okay. And -- and you're aware that the RCB
12 framework was first introduced in the 2016 IRP?

13 A (Witness Watkins) No. I -- I gave you the
14 extent of my knowledge.

15 A (Witness Barber) Yes. We're well aware.

16 Q And though it wasn't approved for compensating
17 behind-the-meter solar experts at first, staff, the company,
18 Georgia Interfaith Power & Light, and GASEIA all worked
19 together following the IRP to address that issue; right?

20 A (Witness Barber) Yes.

21 Q Okay. And in June 2017, the company, GIPL,
22 Southface and GASEIA reached a compromise with respect to
23 applying the RCB framework to compensate exported energy
24 from behind-the-meter solar installations; right?

25 A (Witness Barber) In 2017?

1 Q Yes.

2 A (Witness Barber) Yes, that's correct.

3 Q Yeah. And specifically the joint
4 recommendation was that Georgia Power will pay RNR
5 participants for export generation at the RCB framework
6 solar avoided cost; right?

7 A (Witness Barber) Yes.

8 Q And that joint recommendation was a compromise
9 among those parties; right?

10 It included other provisions, such as
11 increasing the size limit for nonresidential RNR customers;
12 right?

13 A (Witness Barber) Correct.

14 Q And that joint recommendation was approved by
15 order of this Commission in 2017; right?

16 A (Witness Barber) Yes.

17 Q Okay. And the RCB framework was further
18 litigated in the avoided cost docket in early 2021; right?

19 A (Witness Barber) I'm not really sure how much
20 focus was on behind-the-meter in that case. It was really
21 more PURPA related and large QFs. So I don't really know
22 how much focus was --

23 Q You don't remember how much focus was put on
24 the --

25 A (Witness Barber) Behind-the-meter?

1 Q On -- well, not on --

2 A (Witness Barber) Not really.

3 Q -- behind-the-meter, but the value of solar?

4 The avoided cost that the company pays?

5 A (Witness Cook) I would say that there was
6 strong focus on avoided costs, but the context of that
7 discussion was around utility-scale, large generators.

8 Q Okay. And the RCB framework was part of the
9 IRP docket this year; right?

10 A (Witness Cook) Yes. Also --

11 A (Witness Barber) Yeah. Mainly utility-scale
12 discussion.

13 A (Witness Cook) Yeah.

14 Q Well -- but as recently as beginning -- at the
15 beginning of this month, the company and the staff have had
16 continuing discussions on the RCB framework and tweaks and
17 changes that we can make to make it, in both parties' view,
18 the most accurate renewable cost benefit framework that it
19 can be; right?

20 A (Witness Cook) Yes. And I think that staff has
21 pretty consistently maintained that we -- our position is
22 the RCB framework undervalues some components and omits
23 components. And so our position has pretty consistently
24 been that we believe it is typically higher than the current
25 RCB.

1 Q And you agree that there is an order of this
2 Commission that has already said that the RCB framework is
3 what is to be used to value exported energy from
4 behind-the-meter solar installations; right?

5 A (Witness Watkins) Yes. But we're simply trying
6 to respond to the order that asked for us to look at
7 alternatives, if you will.

8 Q Right. But in your response you completely
9 ignore and you didn't even mention the RCB framework, which
10 is the Commission-approved valuation of behind-the-meter
11 solar.

12 A (Witness Watkins) I guess our bad. Excuse me.
13 I think it -- I think it's certainly possible
14 to continue on with it if the Commission decides to do so.

15 A (Witness Cook) And that is the alternative that
16 the company did put forth. So our alternative is to the
17 company's and to the current --

18 A (Witness Watkins) Right.

19 A (Witness Cook) -- monthly.

20 A (Witness Barber) Yeah. I don't think we forgot
21 to put it in. I think we -- we're aware of it, but we only
22 do what the Commission asked, which was to look at other
23 opportunities or mechanisms to look at, including monthly --
24 continuing monthly netting.

25 Q Okay. But when the Commission asks you to

1 provide suggestions on pricing for behind-the-meter solar,
2 do you agree that the renewable cost benefit framework,
3 which is the current approved way of valuing
4 behind-the-meter solar, is one way that this Commission can
5 decide?

6 A (Witness Barber) Absolutely.

7 Q Okay.

8 A (Witness Watkins) Yeah.

9 MR. HEWITSON: Thank you. That's all I have
10 for you today.

11 MADAM CHAIR PRIDEMORE: Redirect.

12 MR. THOMAS: Thank you, Madam Chair.

13 REDIRECT EXAMINATION

14 BY MR. THOMAS:

15 Q Is the point of staff's testimony that it is a
16 policy question for this Commission and that staff has just
17 laid out options for the Commission to consider?

18 A (Witness Barber) Yes.

19 MR. THOMAS: That's all the redirect I have.

20 Thank you.

21 MADAM CHAIR PRIDEMORE: I believe that's it.

22 Any other questions for this panel?

23 (No response.)

24 MR. THOMAS: I'd ask that they be excused.

25 MADAM CHAIR PRIDEMORE: All right. You're

1 excused.

2 (Witnesses were excused.)

3 MADAM CHAIR PRIDEMORE: Okay. Mr. Hill.

4 Is Mr. Hill present?

5 Hi, Mr. Hill.

6 DR. HILL: Hello.

7 MADAM CHAIR PRIDEMORE: Georgia Coalition for

8 Local Governments -- of Local Governments.

9 MS. BROWN: Madam Chair, with your permission,
10 Ms. Ariza will be swearing my witness.

11 MADAM CHAIR PRIDEMORE: Yes.

12 Ms. Ariza.

13 MS. ARIZA: Thank you.

14 Dr. Hill, will you please raise your right
15 hand.

16 Thereupon,

17 DAVID HILL, PH.D.,

18 having been duly sworn, testified as follows:

19 DIRECT EXAMINATION

20 BY MS. ARIZA:

21 Q Would you please state your name for the
22 record, along with your employer and your title.

23 A David Hill. My employer is Energy Futures
24 Group based in Hinesburg, Vermont.

25 Q Thank you.

1 On November 18, 2022, did you file or cause to
2 be filed with this Commission public disclosure testimony
3 and exhibits in a question-and-answer format on behalf of
4 the Georgia Coalition of Local Governments?

5 A I did.

6 Q Did that consist of 31 pages of testimony and
7 one exhibit labeled DGH-1?

8 A Yes, it did.

9 Q If I were to ask you the same questions today
10 as you were asked in your prefiled testimony, would your
11 answers be the same?

12 A They would.

13 MS. ARIZA: Madam Chair, I ask that Dr. Hill's
14 testimony and exhibits be copied into the records as
15 if given here today.

16 MADAM CHAIR PRIDEMORE: So moved.

17 (Whereupon, the prefiled direct testimony
18 of David G. Hill, Ph.D. follows:)

19

20

21

22

23

24

25

**STATE OF GEORGIA
BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION**

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

**DIRECT TESTIMONY OF
David G. Hill, Ph.D.**

**IN SUPPORT OF
THE GEORGIA COALITION OF LOCAL GOVERNMENTS**

November 17, 2022

Direct Testimony of David G. Hill, Ph.D.
On behalf of The Georgia Coalition of Local Governments

Docket No. 44280

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is David G. Hill. I am a Managing Consultant with Energy Futures Group, Inc. My business address is P.O. Box 587, Hinesburg, Vermont 05461.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am testifying on behalf of the Georgia Coalition of Local Governments.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Arts in Political Science and Geography from Middlebury College in 1981, a Master's Degree in Appropriate Technology and International Development from the University of Pennsylvania in 1989, and a Ph.D. in Energy Management and Policy Planning from the University of Pennsylvania in 1993. For the past three decades I have provided economic and environmental analysis on energy system planning, with particular focus on energy efficiency and renewable and distributed energy resources. My recent work includes leading teams on economy-wide scenario modeling of Decarbonization Pathways in Massachusetts and Vermont, and expert testimony and analysis on proposed gas system pilots and infrastructure investments. I have attached a copy of my curriculum vitae in Exhibit DGH-1.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No, but over the course of my career, I have provided testimony in regulatory hearings on more than two dozen occasions and have participated in scores of technical workshops and working groups on behalf of many clients, including participation for more than a decade in planning and administration for renewable

1 energy incentive and net metering programs. Exhibit DGH-1 provides further
2 details on my experience as an expert witness.

3 **II. PURPOSE AND SUMMARY OF RECOMMENDATIONS**

4 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

5 A. The purpose of my testimony is to review Georgia Power Company's (GP or the
6 Company) net metering proposal in Docket No. 44280 as presented in the October
7 20, 2022, Supplemental Direct Testimonies of the Panel of Lee Evans and Larry
8 Legg, and the Supplemental Direct Testimony of Dr. David Gattie. I review and
9 critique GP's current and proposed approach to net metering as being too restrictive
10 and recommend the Commission direct the Company to continue monthly net
11 metering in the coming rate case cycle. After reviewing the Company's net
12 metering proposal, I examine how the Company's concerns over net metering are
13 selective and overstated. My critique includes a review of experience and levels of
14 market development from other jurisdictions to provide context. This experience
15 clearly indicates any undesired rate and cost shifting impacts associated with net
16 metering are small compared to other drivers during early stages of market
17 adoption.

18 I highlight the potential damage the Company proposes to inflict on the rooftop
19 solar market by presenting a brief comparison on customer economics under the
20 proposed revisions. Taking a bit broader perspective, I then examine and critique
21 how the proposed elimination of net metering reflects the disregard and inadequate
22 consideration of rooftop solar and other distributed energy resources (DERs) in the
23 Company's Integrated Resource Planning (IRP). This is a serious concern, as
24 rooftop solar and other DERs can provide high value to the Company's portfolio,
25 today and into the future.

26 Specifically, my testimony contains the following sections: 1) Review the
27 Company's net metering proposal, 2) Discuss and critique the Company's concerns

Direct Testimony of David G. Hill, Ph.D.
On behalf of The Georgia Coalition of Local Governments

Docket No. 44280

1 related to cost shift and rate impacts from monthly net metering, 3) Review and
2 present analysis from the customer's perspective to illustrate the importance of
3 rejecting the Company's proposal to end monthly net metering at this time, 4)
4 Discuss how rooftop solar and other customer owned DERs have potential to
5 contribute to meeting system needs and could be better considered as resources in
6 the Company's Integrated Resource Planning (IRP), and 5) Provide my
7 recommendations for solutions and commitments the Commission can direct the
8 Company take to correct the substantial shortcomings in their proposal.

9 **Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.**

10 **A.** If adopted, the Company's proposed changes to net metering will severely damage
11 the recent growth in Georgia's rooftop solar market. The proposed changes
12 unnecessarily forego opportunities for GP and its customers to gain advantage from
13 the technical advances and cost reductions in the rooftop solar markets, and they
14 are not in the public's best interest. For these reasons, I recommend the
15 Commission direct the Company to maintain monthly net metering during the
16 coming rate-cycle.

17 I also recommend the Commission reject the Company's proposed implementation
18 of the TOU RD rate as a default (for all or any subset of customers). As proposed,
19 the TOU RD rate has extremely serious flaws with respect to inequitable impacts
20 on low-consuming customers, the structure of its non-coincident peak demand
21 charge, and the potential negative implications for the adoption of electric vehicles,
22 battery storage and other flexible load management strategies.

23 Finally, I recommend that as Georgia's rooftop solar market continues to grow, the
24 Commission direct the Company or Commission staff to convene a stakeholder
25 working group tasked with examining options for, and developing, an alternative
26 rate mechanism and transition strategy, to support the sustained long-term growth
27 of distributed energy resources. I provide recommendations on a set of guiding
28 principles to inform the chartering and conduct of this important work.

Direct Testimony of David G. Hill, Ph.D.
On behalf of The Georgia Coalition of Local Governments

III. GEORGIA POWER COMPANY'S PROPOSAL

Q. PLEASE SUMMARIZE THE COMPANY'S NET METERING PROPOSAL AS PRESENTED IN THIS DOCKET.

A. The Company's proposal has three main elements: 1) Discontinue the monthly net metering (NEM) pilot authorized by the Commission in the 2019 rate case¹, 2) Propose that after January 1, 2023, any customers enrolling in a renewable non-renewable (RNR) tariff be moved from Rate R to a three-part rate, such as the TOU-RD rate², and 3) establish a formal framework for customer protection and complaints related to behind the meter generation resources.³

Q. DO YOU AGREE WITH THESE POSITIONS?

A. I strongly disagree with the first two, and I support the third. If implemented, the first two components of the Company's proposal would seriously damage the growth of the rooftop solar market in Georgia. The rationale provided by the Company is based on a set of concerns, each of which I address below, that are based on faulty premise, and that are over-stated given the current state of market development and deployment of monthly net metered systems. The concerns over lost revenue and cost-shifting raised by the Company are not grounded in, nor do they reflect, estimated impacts on the cost of service or revenue requirements, and they should be rejected by the Commission.

Q. CAN YOU BRIEFLY DESCRIBE THE RESULTS FROM THE NEM PILOT?

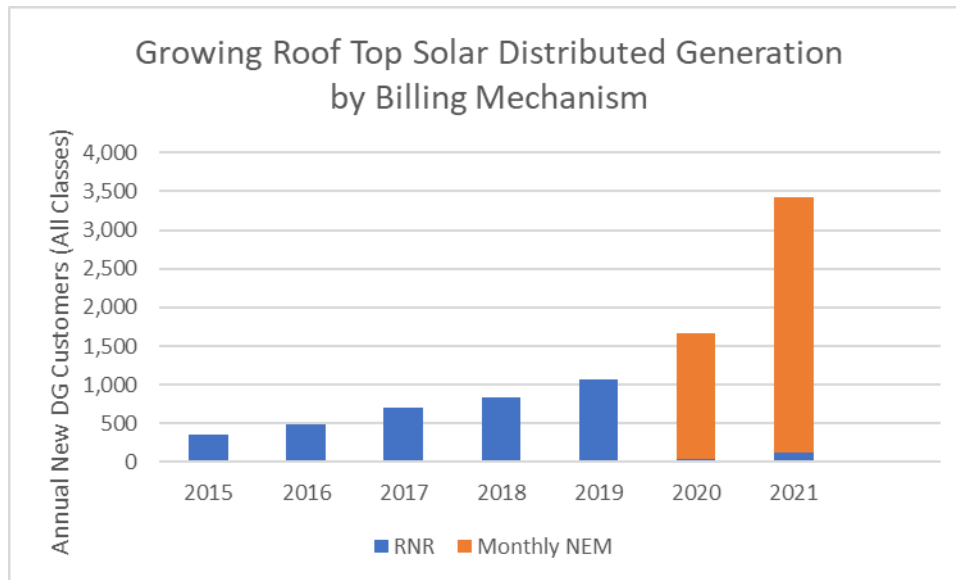
A. The Commission's order to create a net metering pilot in the 2019 rate case supports growth of Georgia's distributed generation rooftop solar market and is aligned with

¹ Supplemental Direct Testimony of Lee Evans and Larry Legg, p. 2, lines 13-14.

² Id. p. 2, lines 17-18.

³ Id. p. 2 lines 19-22.

1 the Solar Power Free-Market Financing Act of 2015.⁴ Figure DH-1 illustrates how
 2 the monthly net metering pilot served to accelerate growth in the market and how
 3 it superseded the pre-existing renewable/nonrenewable (RNR) tariff as the
 4 predominant billing mechanism.⁵



5

6 **Figure DH-1: Growth in Distributed Generation Rooftop Solar Market**

7 The aggregate installed capacity of the interconnected solar facilities represented
 8 in Figure DH-1 is just under 35 MW.⁶ Figure DH-1 illustrates a couple of important
 9 points a) Georgia Power's customers are demonstrating steadily growing interest
 10 and willingness to invest in and contribute to the growth of the distributed solar
 11 market, and b) in only two years, the monthly NEM mechanism resulted in more
 12 installations than in the prior 5 years combined under the RNR mechanism. Georgia
 13 Power's 2022 Integrated Resource Plan⁷ indicates the Company intends to procure
 14 200 MW of distributed generation by 2025. In this light, the Company's proposal
 15 to end monthly net metering, seems ill-timed and contrary to building upon the

⁴ House Bill 57, LC 362633ER.

⁵ Docket Nos. 44160 & 44161, Georgia Power Company's 2022 IRP and 2022 DSM Application STF-DEA Data Request Set Number 1.

⁶ Id. STF-DEA-1-2, c.

⁷ Georgia Power 2022 Integrated Resource Plan, Docket 44160, p. 1-8.

1 nascent success and market response to the NEM offering. As I discuss in Sections
 2 V-VII of my testimony the customer economics for small scale rooftop solar under
 3 NEM are superior to the Company's other solar offerings, and as I discuss below,
 4 their rationale for ending NEM at this time are flawed.

5 **IV. FAULTS WITH GEORGIA POWER'S RATIONAL FOR ENDING NEM**
 6 **PILOT**

7 **Q. GIVEN THIS SUCCESS WHAT ARE THE COMPANY'S REASONS FOR**
 8 **DISCONTINUING THE NEM PILOT?**

9 A. As presented in their filing, the Company's objections boil down to concerns over
 10 lost revenue, and cost shifting between participating and non-participating NEM
 11 customers.

12 Figure 1 in the Supplemental Testimonies of Mr. Legg and Evans illustrates a
 13 simple comparison of the total summer-time monthly bill for a customer with
 14 distributed generation under the RNR tariff, in contrast to the same customer with
 15 monthly net billing. The RNR tariff customer's bill is \$122 while the NEM
 16 customer's bill is \$76, a difference of \$46.⁸ They state, "*This cost shift creates an*
 17 *unjustified and disproportionate subsidy that only benefits the customer*
 18 *participating in the monthly netting pilot.*"⁹ And continue, "*The Company does not*
 19 *recommend continuing to subsidize BTM solar customers at the expense of other*
 20 *customers by using the monthly netting methodology combined with volumetric rate*
 21 *structures.*"¹⁰

22 Elsewhere, Dr. Gattie, another expert witness on the Company's behalf states,
 23 "*However, monthly net metering (or monthly netting here in Georgia) is a separate*
 24 *policy issue that involves shifting costs to ratepayers who do not participate as*

⁸ Supplemental Direct Testimony of Lee Evans and Larry Legg, p. 5 lines 8-9.

⁹ Id. p. 5 lines 16 -17.

¹⁰ Id. p. 6 lines 8-10.

1 solar customer-generators. ***Significantly, my testimony on monthly netting should***
 2 ***not be misconstrued as opposition to residential rooftop solar PV nor should it be***
 3 ***misinterpreted as opposition to compensating solar customer-generators for***
 4 ***electricity exported onto the grid. Quite the opposite, customer-generators should***
 5 ***be compensated for the energy they export to the grid, and at a rate that is fair and***
 6 ***equitable for all Georgia ratepayers and that does not shift costs to ratepayers who***
 7 ***do not participate in distributed solar PV.***¹¹

8 **Q. HOW DO YOU RESPOND TO THESE CONCERNS?**

9 A. First, the Company's emphasis on cost shifting ignores a fundamental feature of
 10 class-based rate making and revenue recovery that is inherent in Georgia and
 11 elsewhere. Calling out a cost shift due to monthly net metering as the reason to
 12 abandon the monthly NEM pilot is a selective objection and it ignores the fact there
 13 is systemic and accepted "cost-shifting" throughout the system. The Company's
 14 opposition to NEM billing is based on an ideologically stringent, but wholly
 15 impractical, structure where all customers pay their full costs and there are no
 16 shared or socialized system costs.

17 Two examples can help illustrate this point. Any customer within a class who uses
 18 less than other customers in effect "shifts" costs towards other customers. Say, for
 19 example, a family has several teenagers who move out of the household, thus
 20 reducing their monthly bills. Or consider a household that installs a more efficient
 21 air conditioning system or heat pump water heater. These are just some of the many
 22 reasons why individual members of a customer class may reduce, or for that matter
 23 increase, their consumption. The utility recovers less revenue from customers who
 24 reduce consumption, and more from customers who are consuming more. Overall
 25 rates are set for a class in a manner allowing the utility to recover its costs along
 26 with a return on the equity (ROE) in the rate base. As I will discuss below, Georgia
 27 Power has consistently collected revenues well above costs resulting in its ROE

¹¹ Supplemental Direct Testimony of Dr. David Gattie, p.18 lines 4-11. Emphasis added.

1 exceeding the central ROE that was authorized by the Commission and used to set
2 rates.

3 There are also clear differences, not reflected in rates, in the costs to serve each
4 customer throughout the system. For example, it may be more expensive to serve
5 customers in less densely populated rural areas of the service territory or be more
6 expensive to serve single family households in comparison to multi-family units.
7 Neighborhoods with underground service may have higher costs than those with
8 overhead poles and wires. Again, rates reflect costs for an entire customer class
9 (not the individual customers in that class) and they also reflect the consumption of
10 the whole class (and not the consumption levels of individual customers within that
11 class). The Company's primary argument against monthly NEM, that it is an
12 "*unjustified and disproportionate subsidy*"¹² is discriminatory against customers
13 who have invested in distributed solar and should be soundly rejected on this basis
14 alone.

15 **Q. BUT AREN'T THE LEVEL OF IMPACTS FROM NEM PILOT A**
16 **LEGITIMATE CONCERN?**

17 A. Not at the current stage of market development. The Company leaves out important
18 information to keep the NEM impacts in perspective. In 2021, Georgia Power
19 reported having 2,296,077 residential customers, with average residential
20 consumption of 12,220 kWh/yr. and an average residential rate of \$0.12 per kWh.¹³
21 Based on these, residential revenues can be calculated as roughly \$3.47 Billion.
22 The 5,000 monthly net metered customers represent 0.2% (two tenths of one
23 percent) of the residential customer base. The annual impact of monthly netting,
24 for which the Company is requesting a rate adjustment to be borne by all customers,
25 is \$1.42 million/yr.¹⁴ As argued above, it is inappropriate for the Company to

¹² Supplemental Direct Testimony of Evans and Legg, p. 5, lines 16-17.

¹³ Georgia Power 2021 Facts & Figures.

¹⁴ Supplemental Direct Testimony of Evans and Legg, p. 11, lines 18-22.

request this rate adjustment to offset the reduced consumption from the subset of customers who have invested in distributed solar. However, even if the Company's argument and calculation of a \$1.42 million are taken on their face value, then the impact per customer is \$0.62 per residential customer per year. The total impact on residential revenues is 0.04% (four hundredths of one percent).

The values cited in the previous paragraph illustrate that Georgia is still in the very early stage of rooftop solar market development. As Dr. Gattie points out in his testimony, monthly net metering has been an often adopted and successful mechanism for promoting solar during the early stages of market development.¹⁵ Figure DH-2 illustrates Georgia's current share of net metered residential customers to California and the rest of the United States based on data presented by Dr. Gattie in his testimony.¹⁶

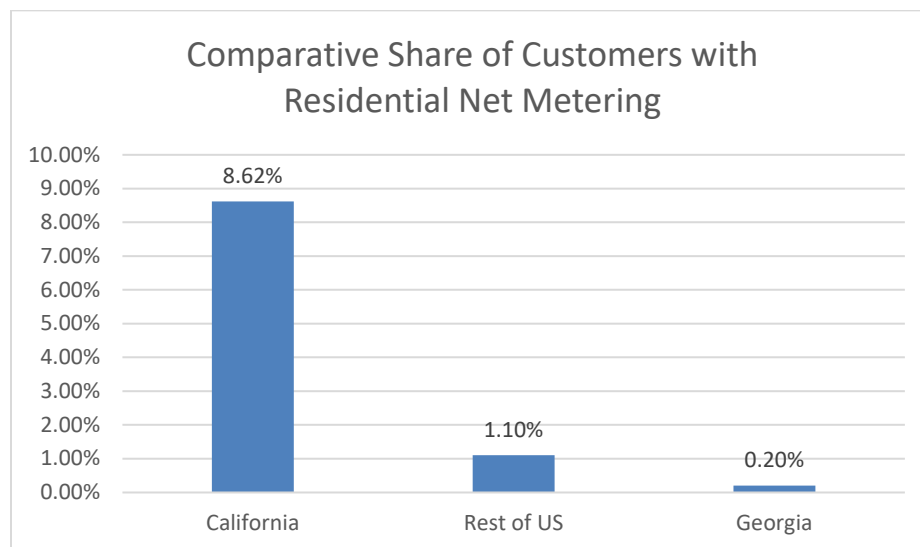


Figure DH-2: Georgia Net Metering is in Early Stages & Could Grow by More than 5X Before Reaching National Average

¹⁵ Supplemental Direct Testimony of Dr. David Gattie, p. 11, lines 20-28.

¹⁶ Id. page 14, lines 1-4.

1 When evaluating the Company's recommendation to terminate the monthly net
 2 metering pilot, it is critical to recognize that Georgia is still in an early stage of
 3 market development, and therefore any impacts are very small. As Dr. Gattie notes,
 4 like Georgia, many states have successfully used NEM to promote early market
 5 development for distributed generation. As illustrated in Figure DH-1 Georgia's
 6 NEM pilot has also been a success and the Company's proposal to terminate net
 7 metering is premature and based on arguments that do not place the impacts in
 8 context.

9 **Q. ARE THERE OTHER FIGURES THAT CAN HELP TO PUT THE LEVEL**
 10 **OF IMPACTS INTO PERSPECTIVE?**

11 A. Yes, as noted in the Direct Testimony of Kevin M. Lucas and Thatcher Young on
 12 behalf of Georgia Solar Energy Industries Association, Solar Energy Industries
 13 Association, and Vote Solar in Docket 44280, the Company's concerns over the
 14 impact of monthly NEM can be seen as wildly out of context when compared with
 15 the Company's request for \$1 billion in additional revenues in 2025, or with the
 16 excess revenues above the authorized return on equity the Company has collected
 17 over the last eleven years.¹⁷ Figure DH-3 provides a graphic comparison
 18 illustrating the NEM impact is ***100 times less*** than the impacts of excess revenue
 19 collections, and on the order of ***1,000 times less*** than the requested revenue increase
 20 for 2025.

¹⁷ Direct Testimony of Kevin Lucas and Thatcher Young, Docket 44280, Section IV, p. 37, lines 7-11.

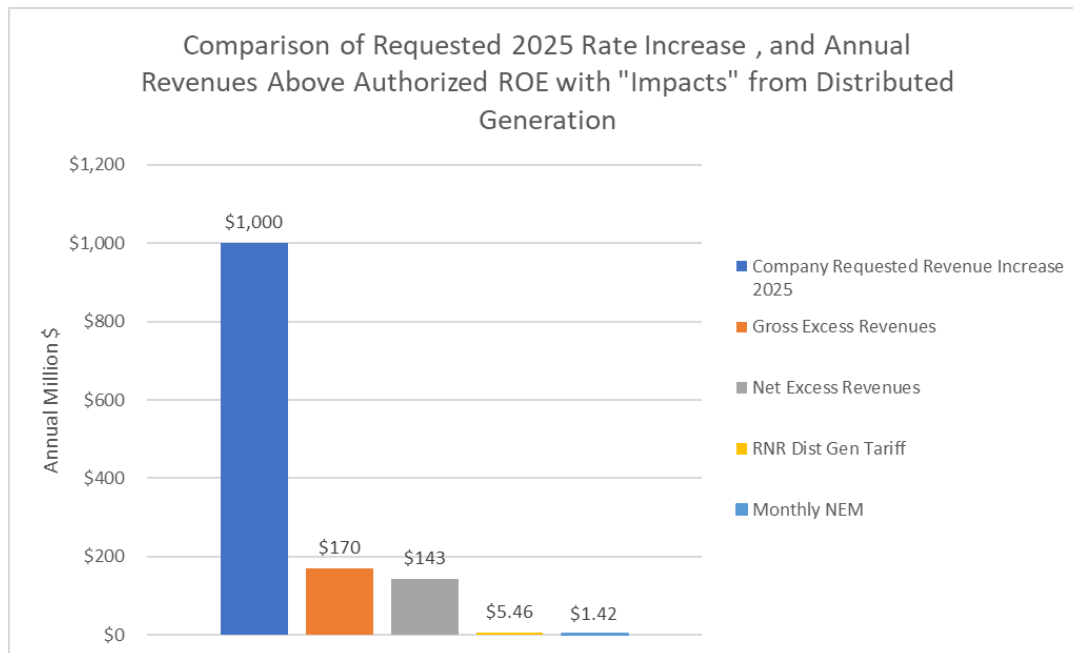


Figure DH-3: Impacts of DG and NEM Of Concern to the Company Are Vanishingly Small Compared to Other Factors

Q. ARE YOU AWARE OF OTHER RESEARCH THAT PUTS NET METERING IMPACTS INTO PERSPECTIVE?

A. I am. Over the years there has been a good amount of research and debate over the pros and cons of net metering as a billing mechanism to support early-stage market growth for distributed solar generation. The following graphic, taken from a 2017 Study conducted by Galen Barbose of Lawrence Berkely National Laboratory¹⁸, serves to illustrate the point that in comparison to other cost drivers, net metering has a relatively small impact today, and extending the analysis out to projected levels in 2030.

¹⁸ Barbose, Galen, 2017. *Putting the Potential Rate Impacts of Distributed Solar into Context*, Lawrence Berkeley National Laboratory.

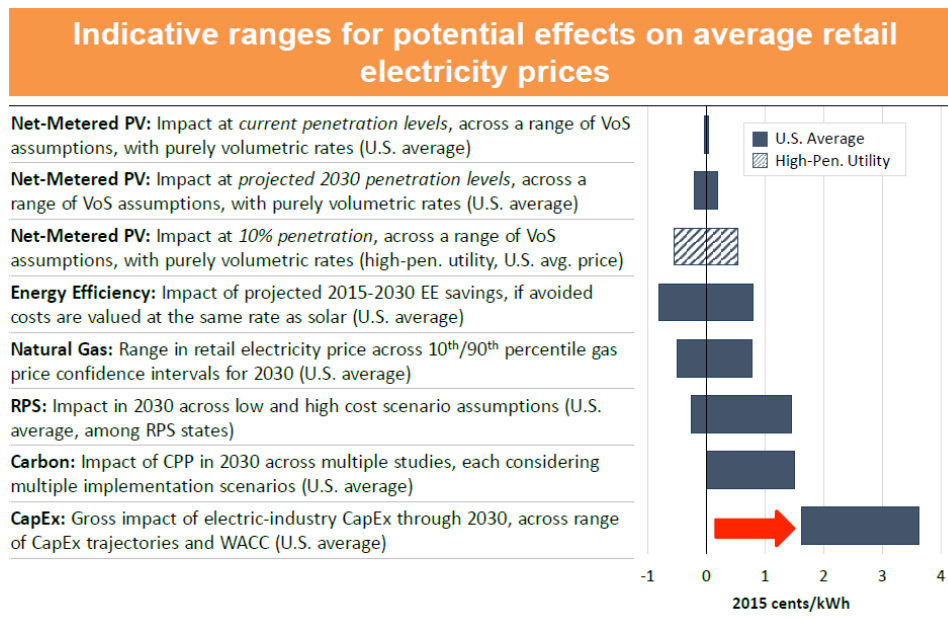


Figure DH-4: The Impact of Net Metering on Retail Electricity Prices is Small When Compared to Other Drivers

As illustrated previously in Figure DH-2, even as it reaches the cap of 5,000 customers in the net metering program, Georgia still has distributed solar saturation well below the national average and therefore is most closely aligned with the top bar in Figure DH-4. Looking forward, the Barbose research indicates the impacts of net metering could be expected to remain smaller than other driving factors through 2030, even if the saturation of distributed solar increases to 10 percent, as indicated by the hatched bar (third from the top in Figure DH-4). A 10 percent saturation in Georgia would be a growth from current levels by a factor of 50 times, equivalent to roughly 230,000 households.

Q. CAN YOU SUMMARIZE YOUR REASONS FOR DISAGREEING WITH THE COMPANY'S PROPOSAL TO END MONTHLY NET METERING?

A. Yes. The main points are:

1. It has been shown in Georgia and elsewhere that monthly net metering is an effective mechanism for encouraging growth of distributed solar resources.

Direct Testimony of David G. Hill, Ph.D.
On behalf of The Georgia Coalition of Local Governments

2. The rationale that monthly net metering should be ended because it is a cost shift ignores the basic fact that cost shifting between customers in a rate class is systemic. The Company's position to call out distributed generation customers is selective and discriminatory.
3. The Company argues that revenue reductions from net metering need to be recovered from other customers. Yet, on a system basis the Company has consistently collected revenues above the authorized central ROE for the past eleven years, in amounts that far exceed any revenue erosion from net metered systems. The Company does not provide any evidence that current or future levels of distributed solar are increasing system costs.
4. The impacts from the monthly net metering are very small. Even if accepted at face value, based on the Company's flawed premise of using a cost shift as the basis for increased revenue requirements, the level of impact is minute in comparison to the other factors driving revenue requirements and rates. The Company proposes to end net metering based on impacts that are 100 times less than the impacts from revenue collection above the authorized ROE, and 1,000 times less than requested revenue increases in the general rate case.

V. CUSTOMER'S PERSPECTIVE – WHY MAINTAINING MONTHLY NET METERING MATTERS

Q. WHY IS IT IMPORTANT TO MAINTAIN MONTHLY NET METERING AND TO REJECT THE COMPANY'S PROPOSAL?

- A. When the monthly netting pilot reached capacity, customers with distributed generation were placed on an instantaneous netting tariff. This alone has had a serious negative impact on customer economics, and this in turn can be expected to slow growth in the small solar market. Under monthly netting, customers receive full retail credit for all solar generation each month, up to their total usage. Under instantaneous netting, by contrast, a customer receives full retail credit for all solar power consumed on site, along with a credit for solar power exported to the grid

Direct Testimony of David G. Hill, Ph.D.
On behalf of The Georgia Coalition of Local Governments

based on the Company's solar avoided energy cost rate, which is cited as being \$0.026763/kWh in the Legg and Evans Testimony.¹⁹

I have conducted an analysis of a customer's perspective of the economics of investing in a rooftop solar system using the National Renewable Energy Laboratory's (NREL) System Advisor Model (SAM).²⁰ Figure DH-5 illustrates that shifting to the instantaneous net metering as proposed by the Company has a significant negative impact on the customer's economics, increasing the simple payback by 8 years. The analysis includes the benefits of an increased 30% Federal Investment Tax Credit.

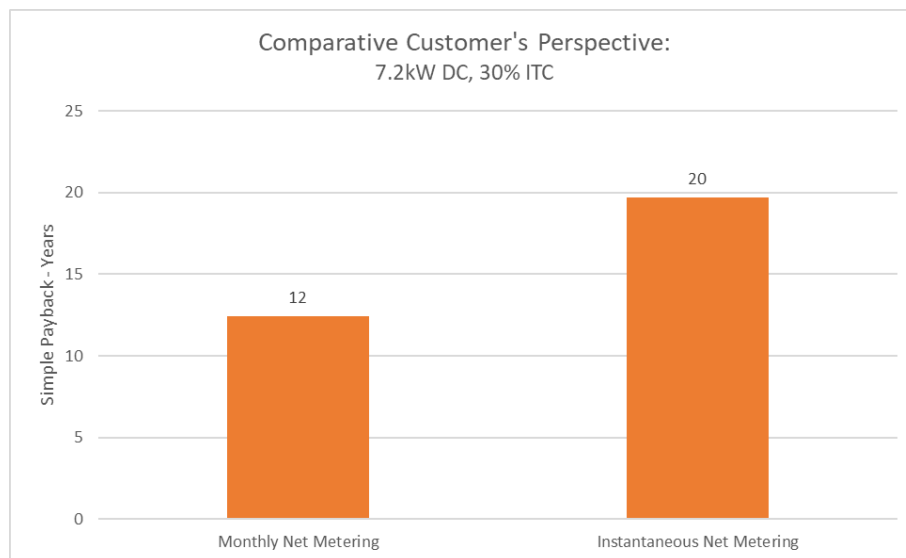


Figure DH-5: Monthly Net Metering Provides More Favorable Customer Economics than Instant Netting

The testimony of Legg and Evans verifies the customer economics for distributed solar will worsen if monthly net metering is replaced by instantaneous net metering. Figure 1 of their testimony indicates the bill in an illustrative summer month with 400 kWh of export and 1,000kWh of consumption for a customer with

¹⁹ Supplemental Direct Testimony of Evans and Legg, p. 4, footnote 3.

²⁰ <https://sam.nrel.gov/>

1 instantaneous net metering would be \$122 while a customer with monthly net
2 metering would have a bill of \$76.²¹

3 Critically, the Company is not advocating for Instantaneous Netting as is currently
4 in place. Rather, the Company is advocating to place all distributed generation
5 customers on a three-part rate, which includes a non-coincident demand charge.
6 Table DH-1 summarizes how this change would dramatically worsen the customer
7 economics for rooftop solar, increasing the simple payback to more than 30 years.

	<u>NEM</u>	<u>Instant</u>	<u>TOU - RD</u>
Annual Bill without system	\$ 1,338	\$ 1,338	\$ 1,251
Annual Bill with system	\$ 232	\$ 642	\$ 819
Annual Net Savings	\$ 1,105	\$ 696	\$ 432
After Tax Cost	\$ 13,717	\$ 13,717	\$ 13,717
Simple Payback	12.4	19.7	31.8

8
9 **Table DH-1: Proposed TOU RD Dramatically Worsens Customer Economics**

10 The testimony of Legg and Evans verifies that the customer economics for
11 distributed generation will be significantly worse if monthly netting is replaced by
12 the Company's proposal. Exhibit LPE/LTI-1 of their testimony indicates that
13 customers can expect to save even less on an annual basis, only \$254 per year, on
14 the TOU-RD rate under instantaneous netting. Based on their analysis the simple
15 payback would be more than 54 years.

16 My analysis and the Company's testimony both indicate ending monthly net
17 metering significantly worsens the customer economics for rooftop solar.
18 Moreover, my analysis and the Company's testimony both indicate that requiring

²¹ Id. Figure 1, p. 5.

1 distributed generation customers to take service under a three-part rate will render
2 rooftop solar entirely uneconomic.

3 The Company's proposal may well be designed to slow or halt the growth of the
4 distributed generation solar market in Georgia. The Commission should reject such
5 a position while directing the Company to enhance their consideration of distributed
6 solar and other DERs in subsequent IRP planning processes. I briefly discuss
7 recommendations on improving the IRP with respect to distributed solar and other
8 distributed energy resources in Section VIII.

9 **VI. EQUITY IMPACTS FROM PROPOSED CHANGES**

10 **Q. WOULD THE COMPANY'S PROPOSAL TO END MONTHLY NET**
11 **METERING IMPACT LOW- AND MODERATE-INCOME**
12 **HOUSEHOLDS?**

13
14 A. Yes, the negative impact on customer economics cited above will influence solar
15 investment decisions for everyone, but the significant increase in the expected
16 payback period will be particularly hard for low- and moderate-income households
17 to justify. Low- and moderate-income households have less ability to take
18 advantage of the federal tax credits that support rooftop solar, since the tax credits
19 are not refundable.

20 Despite these challenges, low- and moderate-income households have been
21 investing in rooftop solar in Georgia. Figures DH-6, DH-7, and DH-8 provide clear
22 evidence that with monthly net metering in place, LMI adoption of rooftop solar
23 has seen a dramatic increase.²² The Company's proposal to end monthly net
24 metering can be expected to have a dramatic and negative effect on these adoption
25 trends.

²² Lawrence Berkely National Laboratory, Solar Demographics Tool: <https://emp.lbl.gov/solar-demographics-tool>

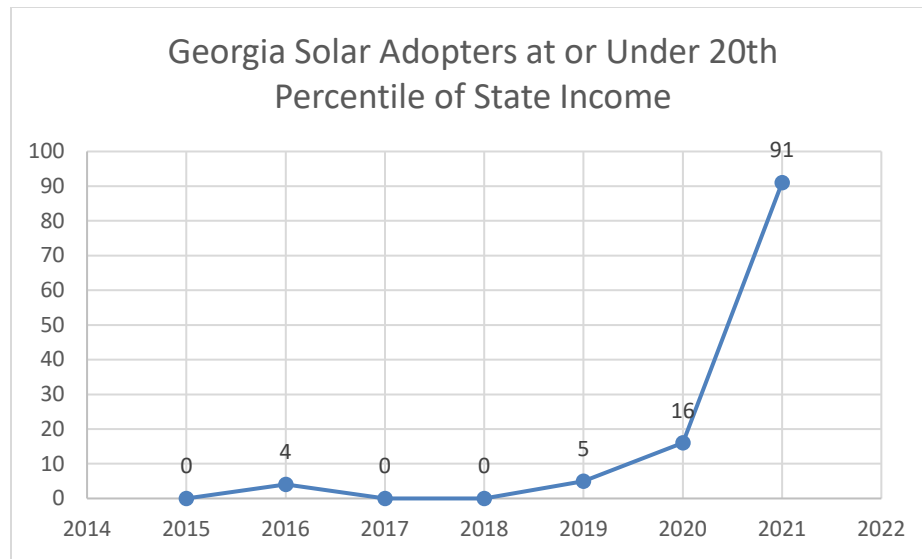


Figure DH-6: More than 100 of Georgia's Lowest Income Households Adopted Solar Under Monthly Netting

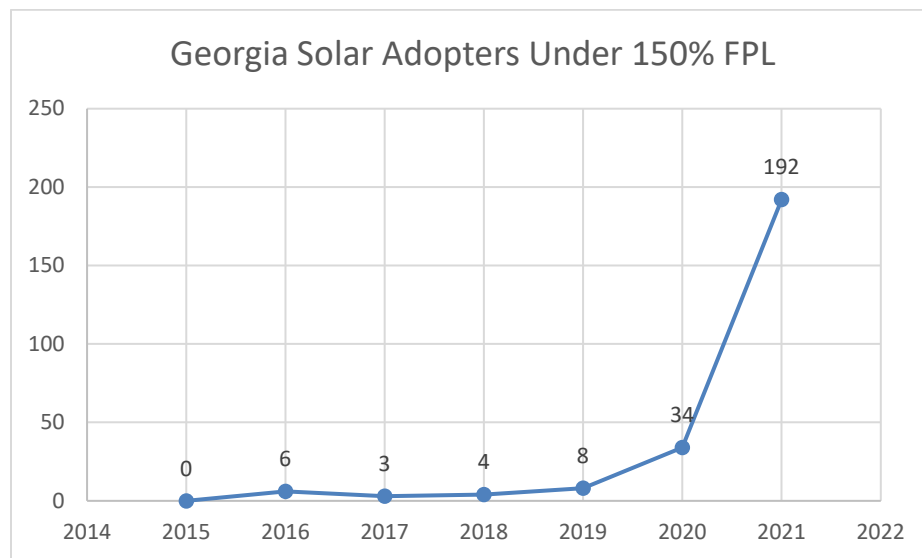


Figure DH-7: Low- and Moderate-Income Solar Adoption Grew Exponentially Under Monthly Netting

Direct Testimony of David G. Hill, Ph.D.
On behalf of The Georgia Coalition of Local Governments

Docket No. 44280

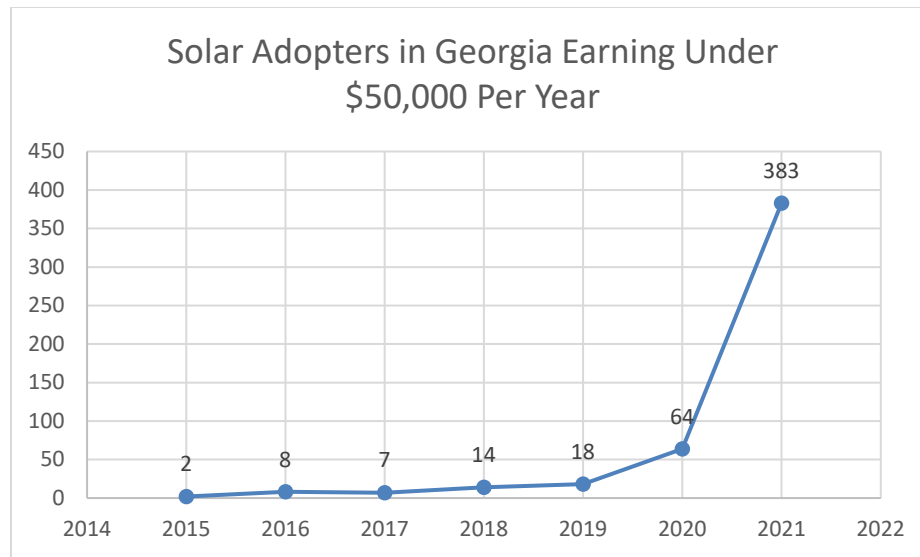


Figure DH-8: More than 400 Families Earning Less than \$50,000 Per Year Adopted Solar Under Monthly Netting

Q. DO YOU HAVE OTHER CONCERNS ON THE INCOME EQUITY IMPACTS OF THE COMPANY'S PROPOSAL?

A. Yes, I am quite concerned that the Company also proposes that after January 1, 2023, all new customers with distributed generation be placed on a three-part rate, such as the TOU-RD rate.²³ Starting in January 2021, the Company made the TOU-RD the default rate for all new residential premises. Empirical evidence shows this rate to be regressive, resulting in higher bills for lower consuming customers, who are more likely to be low- and moderate-income households.

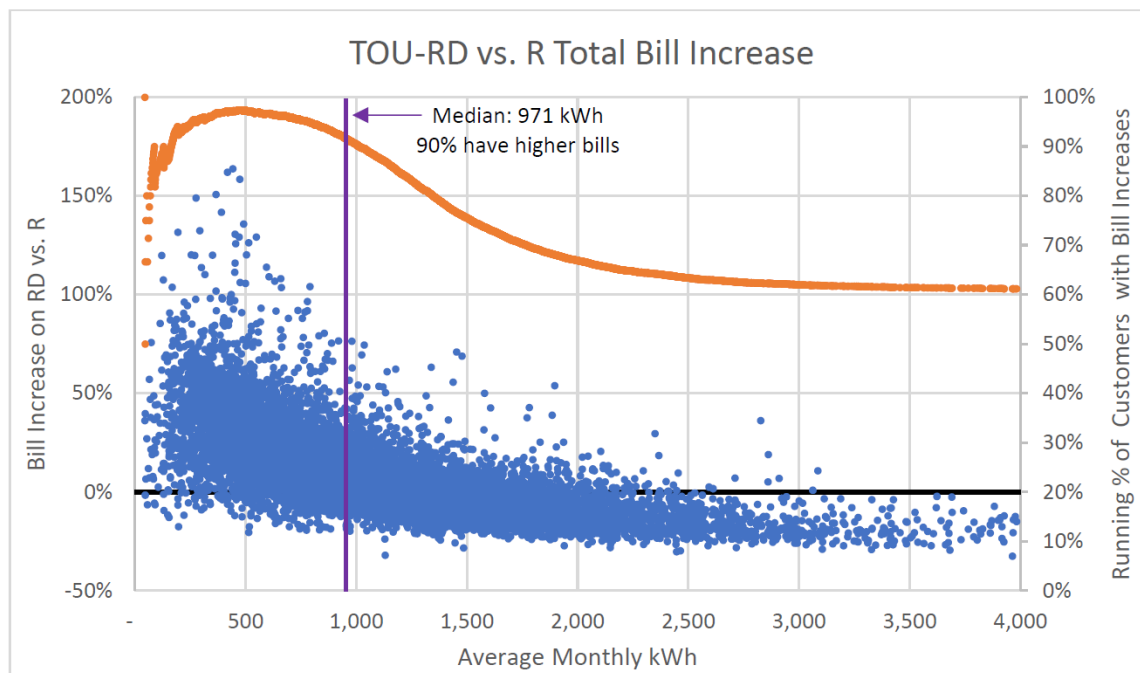
Section V of Mr. Lucas and Young's testimony on behalf of the Solar Energy Industries Association, the Georgia Solar Energy Industry Association, and Vote Solar in Georgia Power Company's 2022 Rate Case presents a detailed (24-page) and compelling review and critique of the TOU-RD rate as a default.²⁴ I agree with

²³ Supplemental Direct Testimony of Evans and Legg, p. 7 lines 5-8.

²⁴ Direct Testimony of Kevin Lucas and Thatcher Young, Docket 44280, Section V, p. 48-72.

1 their critique and characterization of the rate as deeply flawed in its design with
 2 relation to the demand charge components and with their recommendations.

3 Figure DH-7, drawn directly from Mr. Lucas and Young's testimony, illustrates
 4 their empirical analysis of billing data indicating that 90% of the customers with
 5 monthly consumption below the median had higher bills (very often significantly
 6 higher bills) under the TOU-RD rate in comparison to the previous R rate.



7

8 **Figure DH-9: The Company's Proposed Default Rate Results in Higher Bills for**
 9 **Customers with Lower Consumption Levels²⁵**

10 Therefore, in addition to rejecting the Company's net metering proposals based on
 11 the damage that it will do to the market for distributed rooftop solar, the
 12 Commission should also reject the Company's position based on the inequitable
 13 impacts of the proposed changes on energy affordability and solar adoption.

14

²⁵ Id. Figure 1, p. 59.

VII. OTHER SUPPORT FOR DISTRIBUTED SOLAR

Q. DOES THE COMPANY PROVIDE OTHER OPTIONS FOR CUSTOMERS INTERESTED IN DISTRIBUTED SOLAR ENERGY?

A. Yes, the Company offers the year-round distributed generation (DG) customer-sited “CCSP” program (which allows customer-sited solar resources to provide energy to the grid through long-term, fixed price agreements with RECs retired on behalf of the host customer), the Simple Solar Program, the Community Solar Program and two “behind-the-meter” options: the “Energy Offset Only” (EOO) and the “Renewable Non-Renewable Resources” instantaneous netting program. Two programs, the Customer Renewable Supply Procurement (CRSP)²⁶ program and the Distributed Generation Request for Proposals (DG RFP), have closed due to reaching full enrollment.

Q. DO THESE INITIATIVES SERVE THE SAME MARKET OR PROVIDE THE SAME CUSTOMER BENEFITS AS THE NEM PROGRAM THE COMPANY PROPOSES TO END?

A. No. These other options do not serve the same market, nor provide similar customer economic benefits as NEM. The alternatives are geared towards larger commercial customers and are suited for customers willing to pay more for renewable electricity rather than have solar provide savings. They do not provide customer economics that are favorable in comparison to NEM.

For example, the two programs that have reached full enrollment (CRSP and DG RFP) are specifically designed for the C&I sector, the CCSP appears to be geared towards customers who have some degree of legal, administrative and electric power industry expertise (e.g. it involves being able to negotiate and enter into a long-term, fixed price power purchase agreement), and the Simple Solar program

²⁶ The City of Atlanta has applied for the CRSP program waiting on terms and conditions from the Company.

is targeted at customers who do not need any financial benefit, ever, from investing in renewables (the customer pays an additional 1 cent per kWh to Georgia Power so that the Company retires some portion of RECs).²⁷ These programs can be beneficial for participating customers, and can support the development of large, renewable energy plants and assist businesses with meeting voluntary emissions reductions goals. The behind-the-meter EOO program is like the instantaneous net metering program with both resulting in longer payback periods compared to the monthly net metering offer. Ultimately, none of these programs replace the need to continue offering NEM for customers with lower energy demand, fewer financial and technical resources, and those customers who want to see a return on their solar investment rather than those willing to pay a premium.

Q. DO THE COMMUNITY SOLAR OPTIONS OFFERED COMPARE FAVORABLY FOR CUSTOMERS TO NEM?

A No, they do not. The Community Solar (CS) program entails customers paying Georgia Power a monthly Solar Charge rate of \$24.99 (with a proposed increase to \$27.99)²⁸ per one kW block, in addition to the customer's normal cost of electricity; in exchange, the Company offsets the customer's purchase of delivered energy by the amount of energy produced at the solar facility supplying the CS program equivalent to the customer's subscription level. This will vary, based on the array output. Further, "based on the structure of the program, a customer should anticipate the CS charges to participate in the program will exceed any bill credits received."²⁹ Similar to the programs for larger consumers and the C&I sector, this program is designed for customers who have no financial concerns regarding needing to see – even over a twenty-year time horizon – a neutral or cashflow

²⁷ In Georgia Power's most recent, 2022 Integrated Resource Plan, the Company proposes to increase to 1.25 cents. Docket No. 44160 Georgia Power Company's 2022 Integrated Resource Plan. Main Document. Page 14-110.

²⁸ Ibid. Page 14-112.

²⁹ <https://www.georgiapower.com/content/dam/georgia-power/pdfs/residential-pdfs/community-solar-tariff.pdf>

1 positive result from their investment.

2 The Income-Qualified Community Solar program is similarly designed, offering a
 3 household of four living off \$55,000 a year the opportunity to pay an additional
 4 \$6.99 per month to receive one kW block of solar from facilities owned by Georgia
 5 Power. A participating household could be expected to receive modest savings of
 6 roughly \$72/year, based on 1,255kWh/kW of solar output and a retail rate of
 7 \$0.12/kWh. While this program will be helpful in providing a limited solar option
 8 to lower income households, it should be noted that the program is limited to 5,000
 9 1kW blocks and it will be subsidized by non-utility corporate sponsors.³⁰ I
 10 encourage the Company to offer and promote an attractive Community Solar option
 11 for all customers, because as currently designed it is likely the Income-Qualified
 12 Community Solar Program will struggle to scale upwards to a significant degree.³¹

13 **Q. HOW HAS THE CUSTOMER UPTAKE BEEN FOR THE COMMUNITY**
 14 **SOLAR PROGRAM?**

15 A. As shown in Figure DH-10³², there has been minimal customer uptake for the
 16 existing offer. The 2022 IRP mentions a community solar program capacity of 8
 17 MW. As of February 2022, 1,954 blocks have been subscribed. If each block is 1
 18 kW, then the total program subscription has achieved 24% in fifty months.³³
 19 Further, after 2019 when NEM became available, community solar participation
 20 has virtually flatlined.

³⁰ Docket No. 44160 Georgia Power Company's 2022 Integrated Resource Plan. Main Document. Page 14-110. Pages 14-112 and 14-113.

³¹ This program is pending a final ruling from the Public Service Commission.

³² Docket Nos. 44160 & 44161. Georgia Power Company's 2022 IRP and 2022 DSM Application. STF-DEA Data Request Set Number 2.

³³ 1,954 kW divided by 8,000 kW equals 24.4%.

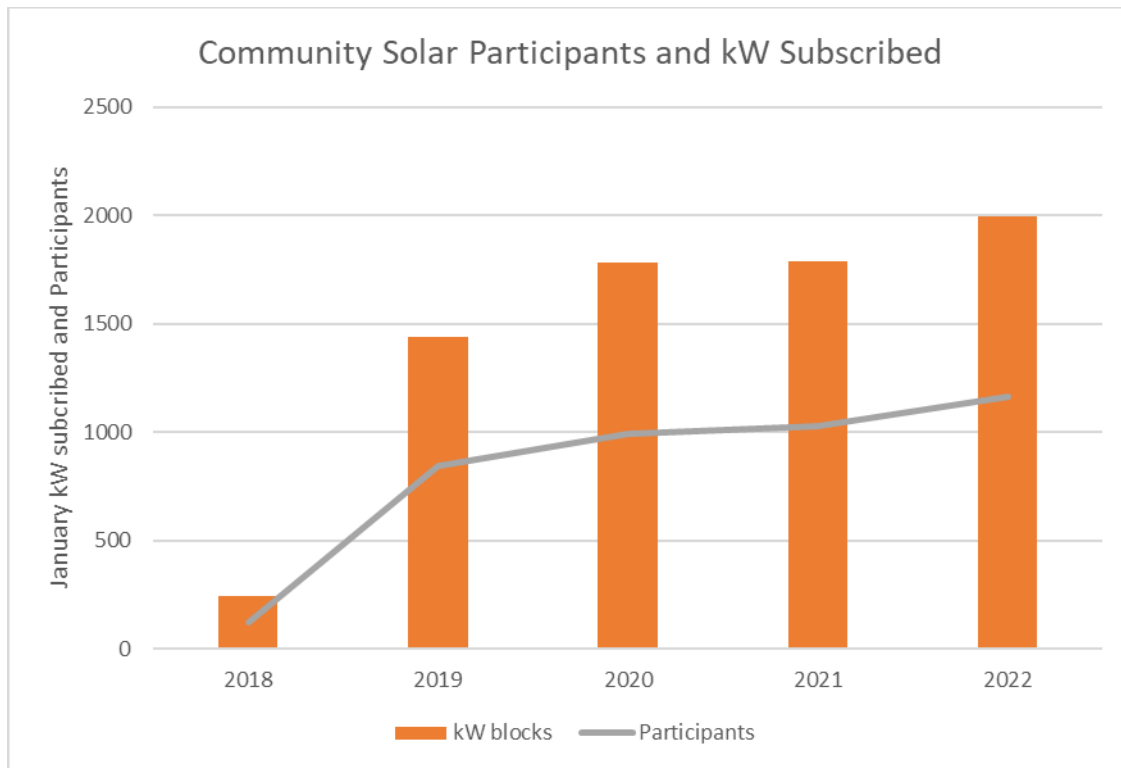


Figure DH-10: Community Solar Participation Flatlined Over Last Two Years in Comparison to NEM Growth in Figure DH-1.

This is a stark difference to the participant interest in the growth in NEM, presented in Figure DH-1, which was fully subscribed within its first two years. This is not surprising as NEM offers customers an ability to realize savings whereas participants in the Company's community solar program need to pay a premium for solar. I support community solar and encourage the Company to redesign each of their community solar offerings so that they can provide participating customers with savings as opposed to always paying a premium.

Q. ARE THERE REASONS IN ADDITION TO THOSE YOU HAVE DISCUSSED ABOVE WHY MAINTAINING NEM DURING THE NEXT RATE CYCLE MATTERS?

A. Yes. First, the 2022 IRP contains several statements along the lines of "Georgia Power is committed to providing industry-leading customer service related to

1 renewable energy”³⁴, including that “Georgia Power’s greatest accomplishment
 2 with respect to renewable development is effectively responding to customer needs
 3 and creating long-term value for customers”.³⁵ While Georgia Power may be
 4 answering the need for some of the larger C&I customers with regards to renewable
 5 energy, it does not appear as though the Company is providing an equal degree of
 6 responsiveness and service, with regards to accessing renewable energy, to all
 7 customers. Customers with less demand and less access to technical and financial
 8 resources are not receiving the same service from the Company as those with more
 9 demand and greater access to technical and financial resources.

10 Second, distributed generation, supported by NEM, is important because north
 11 Georgia needs more generation. Specifically, the IRP states that “there is a
 12 significant gap between generation and load forecasted in north Georgia which will
 13 be further increased by future coal retirements. This gap will require the
 14 transmission system to transport large amounts of energy from south to north
 15 Georgia and place additional strain on the existing transmission system. Moreover,
 16 overreliance on generation from distant geographic regions can create adverse
 17 conditions that aggravate power System reliability and resiliency issues.”³⁶ The IRP
 18 further states that “new local area generation is a critical component of the long-
 19 term solution to continue reliably serving load in north Georgia.”³⁷ But, “options
 20 to add new generation are generally limited by the location of suitable sites. Georgia
 21 Power’s ability to add new transmission assets is similarly limited based on land
 22 and right-of-way needs for optimum location of the lines and substations, as well
 23 as environmental permitting requirements.”³⁸ Meanwhile, Georgia Power
 24 references that economic conditions are deteriorating amongst their coal plants,³⁹

³⁴ P. 14-104 of 2022 IRP.

³⁵ P.14-96 of 2022 IRP.

³⁶ P. 12-88 of 2022 IRP.

³⁷ P. 12-87 of 2022 IRP.

³⁸ P. 12-87 of 2022 IRP.

³⁹ P. 11-76 of 2022 IRP. “Similar to the Company’s other coal resources, economic conditions continue to deteriorate for Plant Wansley.”

1 but that Plant Bowen Units 3-4 will continue to operate because they “remain
2 critical to preserving System reliability and resiliency in north Georgia.”⁴⁰

3 In sum: uneconomic coal plants are continuing to operate because more generation
4 is needed in north Georgia. However, there is limited land in north Georgia and
5 building new large-scale generation and transmission projects can face various
6 environmental and right-of-way challenges. Meanwhile, a program that results in
7 new generation, that has seen significant uptake, including an increase among low-
8 and moderate-income households, that utilizes rooftops, and that leverages and
9 stimulates significant private capital via customers paying for the permitting and
10 construction of the generating array, is not only closed due to being fully enrolled,
11 but the Company now suggests ending the successful program entirely.

12 When asked during cross examination if the Company considered behind the meter
13 resources as a solution in North Georgia, the Company responded with concerns
14 that the resources would not be available and online when contingencies happen.⁴¹
15 Certainly, that might be true if contingencies occur in the evening, but I will note
16 that the Company has not proposed any policies, programs, or incentives to
17 encourage adoption of solar + storage, which could be available and online around
18 the clock to provide the needed services. This lends even further weight to the
19 conclusion that the Company’s proposal may well be designed to suppress
20 customer-sited, behind the meter resources.

21

⁴⁰ P. 11-76 of 2022 IRP.

⁴¹ Hearing Transcript Volume 1, Dockets 44160 and 44161, pg. 328-329

**VIII. TAKING GREATER ADVANTAGE OF DISTRIBUTED SOLAR IN THE
COMPANY'S PLANNING**

**Q. DO YOU HAVE CONCERNS WITH HOW THE COMPANY ASSESSES
THE ROLE AND VALUE OF SOLAR ENERGY AND NET METERING IN
THEIR PROPOSAL?**

A. Yes, Witnesses Evans and Legg state that customers with net metering are “only providing and offsetting the cost of energy” and they are not likely providing “any immediate demand related services when they deliver energy back to the grid”.⁴²

This assumption that distributed generation provides only off-setting energy benefits is ill-advised and unsupported. Solar and distributed solar in Georgia will generate during periods of peak demand, reduce transmission and distribution losses, and at current levels of saturation in Georgia can generally be expected to have beneficial distribution and transmission capacity impacts.

While I have not conducted any detailed analysis of these impacts, Figure DH-11, reproduced from the National Standard Practice Manual for Distributed Energy Resources, provides a stark contrast to the assumption put forward by witnesses Evans and Legg which, if represented below, would have a hollow circle for all impacts other than energy generation.

⁴² Supplemental Direct Testimony of Evans and Legg, p. 10 lines 15-17.

Table 8-1. Potential Impacts of Distributed Generation: Electric Utility System

Type	Utility System Impact	Benefit or Cost	Notes, or Typical Applicability
Generation	Energy Generation	●	Typically benefits because DG reduces electricity generation and system peak demands
	Generation Capacity	●	
	Environmental Compliance	●	
	RPS/CES Compliance	●	
	Market Price Response	●	
	Ancillary Services	●	A benefit or a cost, depending upon DG technology and system conditions; magnitude of benefits and costs may change with deployment rate of DG on particular parts of the distribution system
Transmission	Transmission Capacity	●	A benefit or a cost because DG can increase or decrease transmission peak demand
	Transmission System Losses	●	A benefit because DG reduces transmission volumes
Distribution	Distribution Capacity	●	A benefit or a cost because DG can increase or decrease distribution peak demand
	Distribution System Losses	●	A benefit because DG reduces distribution volumes
	Distribution O&M	●	May add to or relieve congestion and grid management costs
	Distribution Voltage	●	A benefit or a cost, depending upon location-specific grid conditions
General	Financial Incentives	●	A cost to the extent they are relevant
	Program Administration Costs	●	
	Utility Performance Incentives	●	
	Credit and Collection Costs	●	A benefit because customer savings make bill payment easier, especially for low-income customers
	Risk	●	DPV reduces some system risks but adds complexity to system operations
	Reliability	●	Variable DG can support reliability or impose reliability costs at high deployment levels
	Resilience	●	Grids with DG should be easier to restore; islandable systems or systems with ride-through capacity may have faster restoration and reduced recovery times

● = typically a benefit for this resource type; ● = typically a cost for this resource type; ● = either a benefit or cost for this resource type, depending upon the application of the resource; ○ = not relevant for this resource type.

Figure DH-11: Recommended Framework for Distributed Generation Impacts Goes Far Beyond Energy Only Savings as Assumed by Georgia Power.⁴³

Q. DOES THE COMPANY'S ASSUMPTION OF ENERGY ONLY BENEFITS ALSO RAISE CONCERNS IN RELATION TO THE MODELING OF DISTRIBUTED SOLAR IN THEIR PLANNING?

A. Yes, while the IRP is not the focus of my testimony, the energy only assumption also has serious implications for the Company's planning. The consideration of

⁴³ National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources, August 2020, E4theFuture. Table 8.1, page 8-3. <https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/>

benefits and costs in the IRP should be consistent with the framework presented in Figure DH-11. Further, if the Company does not kill distributed solar market growth through their ill-advised proposal to end monthly net metering as this time, then the forecast for distributed solar adoption is a key input into the development of an IRP. Most often utilities model forecasted adoption of distributed solar and/or distributed battery storage as a reduction to the energy and peak load forecast. Since these resources can reduce the utility's load, and potentially offset future load growth and the need for new resources, it is crucial that stakeholders have access to the inputs that go into the development of the forecast. Given the importance of distributed solar and the implications that different levels of distributed solar growth can have on the IRP results, we recommend that the Company work collaboratively and transparently with stakeholders to develop distributed solar forecasts used as inputs for future IRPs.

An example is the IRP process in Indiana, where the utilities hold several public stakeholder meetings⁴⁴ prior to the filing of the IRP to discuss modeling inputs such as the load forecast, electric vehicle and distributed solar forecasts, existing resource costs and operating parameters, new resource costs, accreditation of existing and new resources, commodity forecasts, constraints placed in the model, scenarios that will be evaluated, and modeling results. This type of stakeholder meeting and information sharing are crucial to facilitate transparency in the IRP process. In Indiana, stakeholders can participate in these meetings and submit feedback and/or questions to the utility on any items discussed during the meeting.

AES Indiana held five stakeholder meetings leading to its filing of the 2022 IRP in December 2022. During the first stakeholder workshop⁴⁵, AES Indiana presented

⁴⁴ The utilities have also started to hold technical stakeholder meetings with parties that have signed an NDA to discuss some of the technical items of the IRP that may be confidential in more depth.

⁴⁵ AES Indiana 2022 Integrated Resource Plan Public Advisory Meeting #1. January 24, 2022. Slides 83-90. Retrieved from https://www.aesindiana.com/sites/default/files/2022-01/AES_Indiana_AdvisoryMeeting_FINAL_1-27-22.pdf

1 information related to some of the model parameters used to develop the forecast
 2 for distributed solar, the different scenarios that would be evaluated, and
 3 preliminary forecast results. In conjunction with the meeting, AES Indiana also
 4 released supporting workbooks for the development of the distributed solar forecast
 5 to parties signing non-disclosure agreements (NDAs) to receive access to the data.
 6 After reviewing the information provided by AES Indiana, stakeholders had the
 7 opportunity to submit feedback on any items discussed during the meeting,
 8 including the distributed solar forecast.

9 I and my Energy Futures Group colleagues have experience participating in similar
 10 stakeholder workshops across many different jurisdictions. For any workshop to be
 11 fruitful it is imperative that they are held in a transparent and collaborative manner.
 12 For discussion of distributed solar in a workshop, it will be important for the
 13 Company to provide the assumptions⁴⁶ used to develop the forecasted level(s) of
 14 distributed solar adoption and the results of various levels of adoption impact the
 15 Company's load forecast.

16 **VIII. SUMMARY AND PROPOSED SOLUTIONS**

17 **Q. CAN YOU PLEASE SUMMARIZE YOUR TESTIMONY?**

18 A. The Company's proposed end to NEM is based on a faulty logic over cost shifting,
 19 is overstated based on the level of market adoption, is unfavorable to the economics
 20 for rooftop solar, has negative equity impacts and risks missing the customer and
 21 system benefits of expanded distributed solar generation as a system resource.
 22 Distributed solar generation in Georgia, supported by net metering, can play a
 23 larger role in meeting portfolio objectives such as clean energy targets, improved

⁴⁶ Many distributed solar adoption models are based on payback and some of the inputs may include system installed cost, tax credit assumptions, system size, lifetime of the system, capacity factor, household income, discount rate, and incentives.

1 resilience, grid flexibility, and portfolio diversification while also addressing equity
2 issues.

3 **Q. WHAT ARE YOUR RECOMMENDATIONS AND SOLUTIONS TO**
4 **IMPROVE THE COMPANY'S NET METERING PROPOSAL?**

5 A. I strongly recommend that the Commission reject the Company's net metering
6 proposal, except for taking steps to improve customer protections and consumer
7 education, which I support.

8 The Commission should order the Company to continue monthly NEM at least
9 through next rate cycle. If a numeric cap on the number of NEM participants is
10 deemed necessary, it should be no less than 75,000 customers, a level that still
11 represents a small share, roughly 2.3%, of the residential customer base.

12 The Commission should reject the Company's proposed requirement of the TOU-
13 RD rate as a default for customers with distributed generation. The Company
14 should be directed to revise the design of the TOU-RD to address serious flaws,
15 such as the undue impact on low consuming customers and the inappropriate
16 treatment of demand charge based on non-coincident peak consumption.

17 The Commission should direct the Company to create a workgroup (potentially
18 with facilitation by staff or another non-utility party) to investigate, develop and
19 recommend the next generation of mechanism to support distributed generation
20 solar in Georgia prior to next rate case. This recommendation recognizes that as
21 distributed solar adoption increases (well beyond Georgia's current and near-term
22 levels) there is a need and benefit to mechanisms beyond NEM.

23 As an example, the type of new mechanism to be worked out could be similar to
24 RNR instant netting, but with compensation for export above the current solar
25 avoided cost based on fuller recognition of distributed solar's benefits, including
26 adders for equity or environmental justice.

1 I recommend the following be used as guiding principles and additional supports
2 for the market development as workgroup commences:

- 3 i. Don't create a separate customer class for distributed generation customers.
- 4 ii. Conduct robust financial analyses from the customer's perspective and
5 design any successor mechanism to NEM so that it supports a reasonable
6 payback (e.g., approximately 12 years), thereby encouraging adoption and
7 sustained orderly market development.
- 8 iii. Enhance the analysis of distributed generation in the IRP planning process.
- 9 iv. Consider and conduct robust analysis on mechanisms and rate designs to
10 encourage (but not require) added value through the combination of solar
11 with other distributed energy resources (such as solar+storage, or
12 solar+flexible load management).
- 13 v. Investigate and identify clear objectives related to equity and energy justice
14 issues and design future mechanisms for DG and DERs consistent with and
15 informed by these objectives.
- 16 vi. Design a flexible mechanism, in which specific elements can be modified
17 as market conditions, costs, and benefits change and evolve over time, all
18 within a relatively stable and enduring framework.
- 19 vii. Redesign the Company's community solar offerings so that participation
20 enables participating customers to realize savings rather than simply being
21 willing to pay a premium.

22 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

23 **A.** Yes, it does.

24

Direct Testimony of David G. Hill, Ph.D.
On behalf of The Georgia Coalition of Local Governments

Docket No. 44280

1 Exhibit: DGH-1

2 **Professional Summary**



David Hill joined EFG as a Managing Consultant at the start of 2020, after 22 years of employment with VEIC, most recently as Director of Distributed Resources and a VEIC Policy Fellow. He is known nationally for his advancement of sustainable energy program design and evaluation, and renewable energy policy. David has been the principal investigator and led analysis teams for multi-year stakeholder informed studies on solar market and decarbonization pathways and scenarios. David provides expert testimony and regulatory support; participates in international, national, and state boards; leads policy committees and conferences; provides

15 comprehensive studies of the economic, technical, and
 16 achievable potentials for sustainable energy programming; and supports program budget
 17 planning and implementation. He has led or significantly contributed to the design and
 18 development of efficiency and renewable energy programs with annual budgets of \$100+
 19 million for initiatives in New Jersey, Washington DC, New York, Vermont, Arizona, and
 20 Maryland. Recent work includes expert testimony and whitepaper analyses related to gas
 21 infrastructure investments, pilot programs and planning. He has clients in more than a
 22 dozen states and six countries; several of them are international organizations.

23 **Experience**

24 January 2020 – present: Managing Consultant, Energy Futures Group, Hinesburg,
 25 Vermont (VT)
 26 2014 – 2019: Director, Distributed Energy Resources, Policy Fellow, VEIC, Burlington,
 27 VT
 28 2010 – 2014: Managing Consultant, VEIC, Burlington, VT
 29 2008 – 2010: Deputy Director, Planning and Evaluation, VEIC, Burlington, VT
 30 2000 – 2008: Senior Consultant, VEIC, Burlington, VT
 31 1998 – 2000: Consultant, VEIC, Burlington, VT
 32 1993 – 1998: Research Associate, Tellus Institute and the Boston Center of the
 33 Stockholm Environment Institute

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1 *Testimony as Expert Witness*

2 Expert witness and reports for technical working groups and before commissions on
3 renewable energy, energy efficiency, and gas infrastructure, in Illinois, Vermont, New
4 York, Rhode Island, New Jersey, Maryland, Pennsylvania, South Carolina, for the
5 Federal Energy Regulatory Commission, Nova Scotia and Ontario.

6
7 2022 In the Matter of the Merger of South Jersey Industries, Inc. and Boardwalk
8 Merger Sub, Inc. in Docket No. GM22040270, on behalf of Environmental
9 Defense Fund, State of New Jersey Board of Public Utilities, November 10, 2022.

10 2022 *GTN Xpress Project: A Critical Review of Need, Cost and Impacts*, prepared for
11 the Washington State Office of the Attorney General, and filed with the Federal
12 Energy Regulatory Commission in Docket No. CP22-2-00, on behalf of the States
13 of Washington, California, and Oregon.

14 2022 In the Matter of Avoided Costs for EfficiencyOne's 2023-2025 Demand Side
15 Management Plan Application, before the Nova Scotia Utility and Review Board,
16 on behalf of EfficiencyOne. February 11, 2022.

17 2022 Appearance before the Rhode Island Energy Facilities Siting Review Board,
18 Docket SB-2021-03, regarding a declaratory Order filed by Sea 3 Providence.
19 LLC. Hearing appearance in support of Direct Testimony of Gabrielle Stebbins
20 of Energy Futures Group, on behalf of the Conservation Law Foundation.

21 2021 Nicor Smart Neighborhood and Total Green Pilots. Expert witness testimony on
22 behalf of Citizens Utility Board, Environmental Defense Fund and Natural
23 Resources Defense Council, Docket 21-0098 before the Illinois Commerce
24 Commission.

25 2021 Nicor Renewable Natural Gas Pilot. Expert witness testimony on behalf of
26 Citizens Utility Board and Natural Resources Defense Council, Docket 20-0722
27 before the Illinois Commerce Commission.

28 2020 *NH Saves 2021-2023 Triennial Plan*. Expert witness testimony reviewing joint
29 gas and electric triennial efficiency plan before the New Hampshire Public
30 Service Commission submitted on behalf of Clean Energy New Hampshire, DE
31 20-092.

32 2020 *Dominion Energy South Carolina, 2020 Integrated Resource Plan*. Expert
33 witness testimony before the South Carolina Public Service Commission
34 submitted on behalf of Southern Alliance for Clean Energy and the South
35 Carolina Coastal Conservation League on the characterization and analysis of
36 energy efficiency and demand response in Dominion's 2020 IRP. Docket No.
37 2019-226-E.

38 2019 *Efficiency One 2020-2022 DSM Plan: Portfolio Diversification and Lighting*
39 *Transition*. Expert Witness Testimony submitted on behalf of Efficiency Nova
40 Scotia, to the Nova Scotia Utility and Review Board, Matter 09096.

41 2018 *In the Matter of an Application by Nova Scotia Power for Approval of its*
42 *Advanced Meter Infrastructure Project*. Expert Witness Testimony submitted on
43 behalf of Ecology Action Center, to the Nova Scotia Utility and Review Board,
44 Matter 08349.

- 1 2018 *Becoming an Advanced Solar Economy*. Testimony before the Vermont House
2 Committee on Energy and Technology, Montpelier.
- 3 2017 Maryland Public Service Commission. On behalf of Office of People’s Counsel
4 on EmPOWER Maryland Utilities 2018-2020 plans. Presentation and testimony,
5 October 25-26, 2017.
- 6 2016 Maryland Office of People’s Counsel, EmPOWER Maryland. *Written Comments*
7 *on 2015 Semi Annual (Q3 and Q4) Review*. Presentation and testimony, May 4,
8 2016.
- 9 2015 Maryland Office of People’s Counsel, EmPOWER Maryland. *Written Comments*
10 *on 2015 Semi Annual Review*. Presentation and testimony, October 14-15, 2015.
- 11 2014 Maryland Office of People’s Counsel, EmPOWER Maryland. *Written Comments*
12 *on 2015-2017 Utility Proposed Plans*. Presentation and testimony, October 21-22,
13 2014.
- 14 2014 Maryland Office of People’s Counsel, EmPOWER Maryland. Evaluation of
15 Semi-Annual Reports - Case Nos. 9153-9157. Presentation and testimony, April
16 7, 2014.
- 17 2013 Pennsylvania Public Utility Commission. On behalf of the Office of Consumer
18 Advocate, regarding Petitions of the Pennsylvania Power Company for Approval
19 of its Act 129 Phase II Energy Efficiency and Conservation Plan (Docket Nos. M-
20 2012-2334395 and M-2012-2334392); Petition of Metropolitan Edison Company
21 (Docket No, M-2012-2334387); and Petition of West Penn Power Company
22 (Docket No. M-2012-2334398). Written testimony. January 8, 2013.
- 23 2013 Maryland Office of People’s Counsel, EmPOWER Maryland. *Written comments*
24 *on 2012 Q3-Q4 Semi-Annual Report*. Presentation and testimony, October 2-3,
25 2013.
- 26 2011 Maryland Office of People’s Counsel. *Utility-Specific Comments on the 2012-*
27 *2014 EmPOWER Maryland Program Plans*. Case Nos. 9153-9157. Written
28 testimony. October 19, 2011.
- 29 2011 Maryland Office of People’s Counsel. *Written Comments on 2010 Annual*
30 *Reports, and Q4 2010 reports*. Case Nos. 9153-9157. Presentation and testimony.
31 March 31, 2011.
- 32 2011 Maryland Public Service Commission. On behalf of the Maryland Office of
33 People’s Counsel. *Comments on the 2012-2014 EmPOWER Maryland Utility*
34 *Program Plans*. October 2011.
- 35 2009 Pennsylvania Public Utility Commission. On behalf of the Office of Consumer
36 Advocate, regarding Petition of Duquesne Light Company for Approval of Its
37 Energy Efficiency and Conservation and Demand Response Plan, Docket No. M-
38 2009-2093217. August 7, 2009.
- 39 2005 Ontario Energy Board. On behalf of Green Energy Coalition, regarding Hydro
40 One Networks and Brampton Conservation and Demand Management Plans.
41 February 4, 2005 (written comments) and February 17-18, 2005 (testimony).
- 42 2005 Pennsylvania Public Utility Commission. On behalf of Penn Future, regarding net
43 metering standards. Written comments and testimony. June 2005.
- 44 2005 Pennsylvania Public Utility Commission. On behalf of Penn Future. Written
45 testimony and comments on interconnection standards. April 2005.

Direct Testimony of David G. Hill, Ph.D.
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1 2005 Testimony to the Vermont State Legislature House Committee on Energy and
 2 Natural Resources on Vermont's Solar and Small Wind Incentive Program.
 3 February 9, 2005.

4 **Selected Projects (from more than 100)**

5 **Vermont Agency of Natural Resources.** Co-leader of Vermont Pathways Analysis
 6 team providing technical support and quantitative modeling to the Vermont
 7 Climate Council, leading to adoption of Vermont Climate Action Plan.

8 **Conservation Law Foundation.** Lead author, for "*Rhode Island's Investments in Gas*
 9 *Infrastructure A Review of Critical Issues*", discussing renewable gas potential,
 10 gas planning in relation to greenhouse gas reduction goals and, depreciation
 11 periods for gas new infrastructure.

12 **Institute for Energy Economics and Financial Analysis.** Lead author, for "*Critical*
 13 *Elements in Short Supply: Assessing the Shortcomings of National Grid's Long-*
 14 *Term Capacity Report*", study calling into question proposed natural gas pipeline
 15 investment for New York City region.

16 **Massachusetts Executive Office of Energy and Environmental Affairs.** Senior advisor
 17 for team creating Low Emissions Analysis Platform (LEAP) integrated scenario
 18 modeling to inform Massachusetts efforts to reach greenhouse gas reduction
 19 targets.

20 **Pennsylvania Department of Environmental Protection.** Led team creating scenario
 21 modeling using the Low Emissions Analysis Platform (LEAP) model in support
 22 of two- and half-year study "*Pennsylvania's Solar Future*". Presentations for
 23 modeling review and collaborative stakeholder feedback at more than half a
 24 dozen stakeholder meetings and webinars.

25 **U.S. Department of Energy.** Principal Investigator for a three-year SunShot Initiative
 26 Solar Market Pathways study, investigating the technical, regulatory, and business
 27 model implications of getting 20 percent of Vermont's total electric supply from
 28 solar by 2025.

29 **Sun Shares.** Created and launched, and responsible for management and business
 30 development of, a community solar business subsidiary to provide "Easy and
 31 Affordable Solar for Employers and their Employees," 2015 – present.

32 **New Jersey Clean Energy Program.** Program design and policy advisor for the
 33 renewable energy program for more than a decade.

34 **Rhode Island Office of Energy Resources.** Strategic Advisor on State Energy Plan and
 35 System Reliability Procurement and Distributed Generation programs.

36 **Alaska Energy Authority.** Principal consultant for two studies on renewable and energy
 37 efficiency financing and funding strategies.

38 **New York State Energy Research and Development Authority (NYSERDA).** Twice
 39 led the renewable energy analysis for 20-year forecast of energy efficiency and
 40 renewable energy potential, 2003 and 2012.

- 1 **World Bank.** Expert consultant on a short-term study of efficiency and micro- / mini-
 2 grid opportunities in Tanzania, 2014.
 3 **Arizona Public Service.** Managed a rapid assessment and redesign of PV and solar hot
 4 water incentives, 2009.

5 *Selected Presentations*

- 6 2017 Sun Shares, Easy and Affordable Solar for Employers and their Employees,
 7 American Solar Energy Society, Solar 2017, Denver.
 8 2017 Vermont Solar Market Pathways, American Solar Energy Society, Solar 2017,
 9 Denver.
 10 2016 *Oxymoron: Harmonizing Distributed Energy Integration Realities with Policy*
 11 *Frameworks*. Solar Power International.
 12 2015 World Bank, International Conference on Energy Efficiency in Cities, Puebla
 13 New Mexico. Invited Panel speaker on Efficiency Vermont and Third-Party
 14 Administration Model. February, 2015.
 15 2015 *Vermont Solar Market Pathways*. Presentations at Solar 2015 (State College,
 16 Pennsylvania), and Renewable Energy Vermont Conference.
 17 2014 New York State Energy Research and Development Authority (NYSERDA),
 18 Renewable Energy Potential Study Results, Albany, NY.
 19 2013 *Transformative Energy Planning*. Invited speaker at Innovations in Renewable
 20 Energy Symposium, Metcalf Institute for Marine and Environmental Reporting,
 21 Narragansett, Rhode Island.
 22 2012 World Renewable Energy Forum, 2012 – Welcome Address and Introduction of
 23 Keynote Plenary Speakers. American Solar Energy Society, Denver.
 24 2012 *Efficiency Vermont: A Successful Statewide Clean Energy Utility Model*.
 25 Presented at the 2012 Business of Clean Energy in Alaska Conference,
 26 Anchorage.
 27 2011 Nova Scotia Feed In Tariff Forum: Invited speaker for two panels addressing
 28 Regional Coordination and Export Potential and International Feed-in Tariffs.
 29 2011 *Integrating Renewable Energy and Efficiency Services*. Presentation to the Clean
 30 Energy States Alliance Fall 2011 Meeting, Washington, DC.
 31 2010 *The Potential for Energy Efficiency and Renewables as Resources in Wholesale*
 32 *Capacity Markets*, Presentation at EUEC 2010 Conference, Phoenix, AZ.
 33 2008 “Technology and Policy; Getting it Right.” Solar Power International, Invited
 34 panel speaker. San Diego, California.
 35 2008 *Solar Market Transition in New Jersey: Promise and Progress towards Sustained*
 36 *Growth*. Solar 2008, American Solar Energy Society.
 37 2008 *Review of Efficiency Vermont Administrative Structure and Experience*. Penn
 38 Future 2008 Clean Energy Conference, May 2008.
 39 2006 *Scoping Analysis of Potential Photovoltaic Contributions Towards Offsetting*
 40 *Transmission System Upgrades in Southern Vermont*. Solar 2006, American Solar
 41 Energy Society.

- 1 2006 *Growing New Construction Markets for Photovoltaics: Recent Strategies and*
2 *Activities from LIPA's Solar Pioneer Program*. Solar 2006, American Solar
3 Energy Society, 2006.
- 4 2005 *Market Response to Photovoltaic Incentive Offerings: An Analysis of Trends and*
5 *Indicators*. Presented at the International Solar Energy Society Solar World
6 Congress, 2005.
- 7 2003 *Solar Energy Value and Opportunities in Vermont*, Invited Session Panel
8 Moderator and Speaker, 2nd Annual Power for a New Economy Conference,
9 Burlington, Vermont, October 8, 2003. Renewable Energy Vermont.
- 10 2003 *Renewable Energy Case Studies: Redefining the Models, Refining the Messages,*
11 *and Getting the Word Out*, Invited Session Panel Moderator, Solar 2003 National
12 Solar Energy Conference, Austin, Texas June 22, 2003. American Solar Energy
13 Society.
- 14 2002 *Transforming Markets for Customer Sited Clean Renewable Energy: Connecting*
15 *Field Experience with Lessons from the Efficiency World*, Invited Session Panel
16 Moderator, Solar 2002 National Solar Energy Conference, Reno, Nevada June 18,
17 2002. American Solar Energy Society.
- 18 1997 *IDENTIFY: Improving Industrial Energy Efficiency and Mitigating Global*
19 *Climate Change*. Software and paper prepared for the United Nations Industrial
20 Development Organization, presented at the 1997 ACEEE Summer Study on
21 Energy Efficiency in Industry.
- 22 1997 *E2/FINANCE: A Software System for Evaluating Industrial Eco-Efficiency*
23 *Opportunities*, sponsored by the U.S. Department of Energy. ACEEE 1997
24 Summer Study on Energy Efficiency in Industry.
- 25 1995 *Process Evaluation of Three Gas Utility Commercial Industrial Demand Side*
26 *Programs*. Prepared for the Colonial Gas Company, and presented at ACEEE
27 1995 Summer Study on Energy Efficiency in Industry.

28 ***Selected Publications***

- 29 2017 Smart Electric Power Alliance, 51st State Initiative, *Role of Utilities in the*
30 *Transforming Energy Economy of the 51st State*, September 2017.
- 31 2016 *Vermont Solar Market Pathways: From a Developed to an Advanced Solar*
32 *Economy*. A Phase II Roadmap document prepared for the *Smart Electric Power*
33 *Alliance 51st State Initiative*.
- 34 2016 *Vermont Solar Market Pathways*, Vols. 1-4. U.S. Department of Energy, Sun
35 Shot Initiative, Office of Energy Efficiency and Renewable Energy. Award DE-
36 EE-0006911. www.Vermontsolarpathways.org.
- 37 2016 *Energy Efficiency Program Evaluation and Financing Needs Assessment*. Report
38 prepared for the Alaska Energy Authority, May 2016.
- 39 2015 *Michigan Renewable Resource Assessment*. Final Report, prepared for the
40 Michigan Public Service Commission Staff under agreement with the Clean
41 Energy States Alliance. April 2015.

- 1 2012 *Renewable Energy Grant Recommendation Program: Process and Impact*
- 2 *Evaluations*. Principal in Charge for comprehensive two-volume study. Alaska
- 3 Energy Authority.
- 4 2011 “Solar in Nepal: Small Systems, Big Benefits.” *Solar Today*. July / August 2011.
- 5 2011 “National Clean Energy Standard: Congress Needs to Design It Properly.”
- 6 Perspective with Shaun McGrath and Jeff Lyng. *Solar Today*. July / August
- 7 2011.
- 8 2010 “National RPS Now!” *Solar Today*. July / August 2010.
- 9 2009 “Carbon Regulation: What’s the Most Effective Path?” *Solar Today*. June 2009.
- 10 2009 “Policy Recommendations for the 111th Congress: Tackling Climate Change and
- 11 Creating a Green Economy.” Prepared by the American Solar Energy Society
- 12 Policy Committee.
- 13 2008 “Pennsylvania Solar Assessment.” Final Report, November 25, 2008.
- 14 Incorporated into American Council for an Energy-Efficient Economy, *Potential*
- 15 *for Energy Efficiency, Demand Response, and Onsite Solar Energy in*
- 16 *Pennsylvania*. ACEEE Report No. E093. Washington, DC: ACEEE, April 2009.
- 17 2008 “Solar Market Transition in New Jersey: Promise and Progress towards Sustained
- 18 Growth.” *Proceedings of Solar 2008*, American Solar Energy Society.
- 19 2004 “Cost Effective Contributions to New York’s Greenhouse Gas Reduction Targets
- 20 from Energy Efficiency and Renewable Energy Resources.” *Proceedings of 2004*
- 21 *ACEEE Summer Study on Energy Efficiency in Buildings*.
- 22 2002 “The Ten Percent Challenge: A Participatory Community Scale Climate
- 23 Campaign.” *Proceedings of 2002 ACEEE Summer Study on Energy Efficiency in*
- 24 *Buildings*. Volume 9, (with Tom Buckley, Jennifer Green, and Debra Sachs).
- 25 2000 “Implementing and Monitoring Community-Based Climate Action Plans.”
- 26 *Proceedings of 2000 ACEEE Summer Study on Energy Efficiency in Buildings*.
- 27 Volume 9, pp. 149-160 (with Tom Buckley, Mark Eldridge, Debra Sachs, and
- 28 Abby Young).
- 29 1998 *Eco-Efficiency Financing Resource Directory*. Electronic web-site, and printed
- 30 directory prepared for the Environmental Protection Agency, Region I, New
- 31 England.

32 ***Regulatory and Other Governmental / NGO Documents***

- 33 2000 – 2012 *New Jersey’s Clean Energy Programs – Honeywell Team Program Plans*.
- 34 Led team on designing and implementing of Renewable Energy Program
- 35 plans and initiatives. Many program plans and strategies for transition to
- 36 market-based incentives.
- 37 1998 – 2008 *Long Island Power Authority’s Clean Energy Initiative*. Lead Technical
- 38 and Senior Advisor on Renewable Energy Plans, including the Solar
- 39 Pioneer Initiative and Residential Energy Efficiency Programs.
- 40 2000 *The Climate Action Plan: A Plan to Save Energy and Reduce Greenhouse*
- 41 *Gas Emissions*, Lead author for the Burlington (Vermont) Climate
- 42 Protection Task Force.

- 1 1998 *Home Weatherization Assistance Program Environmental Impact*
2 *Analysis*. Prepared for the Ohio Department of Development, Office of
3 Energy Efficiency.
- 4 1997 *Achieving Public Policy Objectives Under Retail Competition: The Role of*
5 *Customer Aggregation*. Prepared for the Colorado Governor's Office of
6 Energy Conservation.
- 7 1997 *IDENTIFY: Improving Industrial Energy Efficiency and Mitigating Global*
8 *Climate Change*, software and paper. For the United Nations Industrial
9 Development Organization.
- 10 1997 *Review of the Swaziland Energy Information System and Report on LEAP*
11 *Training Activities*. Prepared for the Ministry of Natural Resources and
12 Energy, Government Kingdom of Swaziland.
- 13 1996 *Evaluation of the IDB's Policies and Practices in Support of Renewable*
14 *Energy and Energy Efficiency: A Report to the Inter-American*
15 *Development Bank*. Brower and Company and Tellus Institute.
- 16 1996 *Action Plan for the Massachusetts' Industrial Services Program (ISP)*,
17 prepared for the Sustainable Industries Initiative of the Corporation for
18 Business Work and Learning.
- 19 1995 *Framework for National Energy Planning: Mission Report*, The Republic
20 of Maldives. United Nations Department for Development Support and
21 Management Services.
- 22 1994 *The SEI / UNEP Fuel Chain Project: Methods, Issues, and Case Studies*
23 *in Developing Countries. Venezuela Case Study*.
- 24 1994 *Future Energy Requirements for Africa's Agriculture (Sudan Case Study)*.
25 Report to the African Development Bank by the UN Food and Agriculture
26 Organization.
- 27 1994 Report to the Idaho Public Utility Commission on Suggested Cost
28 Allowances for the Idaho Power Company's DSM Programs. Prepared
29 for the Idaho Public Utilities Commission, Tellus Report No. 94-177.
- 30 1994 Review of Pennsylvania Electric Company's 1995 Demand Side
31 Management Filing. Prepared for: Pennsylvania Office of Consumer
32 Advocate. Tellus Study No. 94-071.
- 33 1994 Review of Union Electric Company's Electric Utility Resource Planning
34 Compliance Filings. Prepared for: The Missouri Office of Public Counsel.
35 Tellus Study No. 93-300.
- 36 1994 *Incorporating Environmental Externalities in Energy Decisions: A Guide*
37 *for Energy Planners*. A Report to the Swedish International Development
38 Agency. SEI-B Report No. 91-157.

39 **Leadership**

- 40 2017 – 2019 Energy Coop of Vermont, Board Member and Treasurer.
- 41 2013 Solar 2013, “Power Forward, Baltimore Maryland.” Chair of Conference
42 Advisory Committee responsible for recruiting and coordinating four main
43 conference plenary sessions.

Direct Testimony of David G. Hill, Ph.D.
On behalf of The Georgia Coalition of Local Governments

- 1 2012 – 2013 American Solar Energy Society (ASES), Chair of the Board.
- 2 2012 Policy Track Chair for the World Renewable Energy Forum, Denver,
- 3 Colorado, May.
- 4 2009 – 2012 ASES Policy Committee, Board Member and Chair.
- 5 2007 Vermont Governor's Climate Change Committee, Member of the Plenary
- 6 Working Group.
- 7 2000 – 2010 Renewable Energy Vermont, Founding Board Member, Past Board Chair.

8 **Education**

- 9 Ph.D., Energy Management and Policy Planning, University of Pennsylvania,
- 10 Philadelphia, Pennsylvania (PA), 1993.
- 11 • Fulbright Scholar: Research on energy decision-making in rural Nepal, 1991 –
- 12 1993.
- 13 Master's, Appropriate Technology and International Development, University of
- 14 Pennsylvania, Philadelphia, PA, 1989.
- 15 B.A., Geography and Political Science, Middlebury College, Middlebury, VT, 1986.

16 ***Other Qualifications***

- 17 **Nepal, Himalayan Light Foundation.** Installed solar lighting systems in 3 remote health
- 18 clinics and 3 homes, 2010.
- 19 **Advanced PV Installation certificate.** Solar Energy International, 2010.
- 20 **Peace Corps volunteer.** Sierra Leone, 1984 – 1986.

21 **Languages**

- 22 • Nepali: ILR Level 3, speaking; ILR Level 2, reading
- 23 • Krio and Mende (Sierra Leone): ILR Level 2, speaking

24 **Software competency**

- 25 • LEAP (Low Emissions Analysis Platform), Stockholm Environment Institute.
- 26 Former trainer and current Principal Investigator of team using scenario modeling
- 27 on three projects.
- 28 • NREL System Advisor Model. Financial and technical modeling tool for
- 29 renewable energy systems.
- 30

31

32

33

1 **CERTIFICATE OF SERVICE**

2
3 **Hinesburg, Vermont**

4
5 Personally, appeared before the undersigned authorized officer in the state and
6 county aforesaid, David G. Hill, who after being duly sworn, deposes and says that he is
7 an expert witness for the Georgia Coalition of Local Governments and that the facts
8 contained in the foregoing Testimony of David G. Hill, for Docket 44280 are true and
9 correct to the best of his information and knowledge.

10
11 This 16th day of November 2022.

12
13
14 -----
15 David G. Hill
16 Energy Futures Group, Inc.
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Direct Testimony of David G. Hill, Ph.D.
On behalf of The Georgia Coalition of Local Governments

Docket No. 44280

CERTIFICATE OF SERVICE

I hereby certify that the foregoing 2022 Rate Case Testimony of David G. Hill for the Georgia Coalition of Local Governments were filed in Docket 44280 with the Georgia Public Service Commission by electronic delivery on the 18th day of November, 2022. An electric copy of the same was served upon all parties listed below by electronic mail as follows:

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1 MS. ARIZA: And that his prefiled testimony and
2 exhibit be marked CLG-6 and CLG-7.

3 MADAM CHAIR PRIDEMORE: So moved. So marked.

4 (The documents referred to were marked for
5 identification as Georgia Coalition of Local
6 Governments Exhibits CLG-6 and CLG-7.)

7 MS. ARIZA: Madam Chair, could Dr. Hill please
8 briefly summarize his testimony for the Commission?

9 MADAM CHAIR PRIDEMORE: Go ahead, Dr. Hill.

10 DR. HILL: Thank you very much, Mrs. Chairwoman
11 and Commissioners.

12 In my testimony, I review and critique Georgia
13 Power's current and proposed approach to net metering
14 as being too restrictive and recommend the Commission
15 direct the company to continue monthly net metering
16 in the coming rate case cycle.

17 My review of the company's net metering
18 proposal indicates the company's concerns over net
19 metering are selective and overstated. My critique
20 includes a review of experience and levels of market
21 development from other jurisdictions to provide
22 context. This experience clearly indicates any
23 undesired rate and cost-shifting impacts associated
24 with net metering are small compared to other drivers
25 during early stages of market development.

1 I highlight the potential damage the company
2 proposes to inflict upon the rooftop solar market by
3 presenting a brief comparison on the customer
4 economics under the proposed revisions. Taking a bit
5 of a broader perspective, I also examine and critique
6 how the proposed elimination of net metering reflects
7 the disregard and inadequate consideration of rooftop
8 solar and other distributed energy resources in the
9 company's integrated resource planning.

10 This is a serious concern as rooftop solar and
11 other distributed energy resources can provide high
12 value to the company's portfolio today and into the
13 future.

14 If adopted, the company's proposed changes to
15 net metering will severely damage the recent growth
16 in Georgia's rooftop solar market. Indeed, the only
17 rationale for accepting the company's proposed
18 changes is that the Commission also would like to see
19 an abrupt and dramatic termination of activity in
20 this market.

21 The proposed changes unnecessarily forego
22 opportunities for Georgia Power and its customers to
23 gain advantage from the technical advances and cost
24 reductions in rooftop solar and they are not in the
25 public's best interest. For these reasons, I

1 recommend the Commission direct the company to
2 maintain monthly net metering during the coming rate
3 cycle.

4 I also recommend the Commission reject the
5 company's proposed implementation of the TOU-RD rate
6 as a default for all or any subset of customers. As
7 proposed, the TOU-RD as a default has extremely
8 serious flaws with respect to inequitable impacts on
9 low-consuming customers, the structure of its
10 noncoincident peak demand charge, and the potential
11 negative implications of this for the adoption of
12 electric vehicles, battery storage, and other
13 flexible load management strategies.

14 Finally, I recommend that as Georgia's rooftop
15 solar market continues to grow, the Commission direct
16 the company or Commission staff to convene a
17 stakeholder working group tasked with examining
18 options for and developing an alternative rate
19 mechanism and transition strategy to support the
20 sustained long-term growth of distributed energy
21 resources. I provide a set of guiding principles to
22 inform the chartering and the conduct of this
23 important work.

24 The company's main concern on cost shift
25 ignores a fundamental feature of class-based rate

1 making and revenue recovery that is inherent in
2 Georgian and elsewhere. Calling out a cost shift due
3 to monthly net metering is the reason to abandon
4 monthly net metering -- the monthly net metering
5 pilot is a selective objective and ignores the fact
6 that there is systematic and accepted cost shifting
7 throughout the system.

8 The company's opposition to net monthly
9 netting -- monthly net -- monthly net billing is
10 based on an ideologically stringent, but wholly
11 impractical, structure where all customers pay their
12 full costs and there are no shared system costs.

13 There are clear differences not reflected in
14 rates in the cost to serve each customer throughout
15 the system. For example, it may be more expensive to
16 serve customers in less densely populated rural areas
17 of the service territory, or be more expensive to
18 serve single-family households in comparison to
19 multifamily units. Neighborhoods with underground
20 service may have higher costs than those with
21 overhead poles and wires.

22 Again, rates reflect costs for an entire
23 customer class and not the individual customers in
24 this class. And they also reflect the consumption of
25 the whole class and not the consumption levels of

1 individual customers within that class.

2 The company's primary argument against monthly
3 net metering is that it is an unjustified and
4 disproportionate subsidy. It's discriminatory
5 against customers who have invested in distributed
6 solar and it should be soundly rejected on this basis
7 alone.

8 I also address how the current state of market
9 development, the impacts of monthly net metering are
10 extremely small. The company leaves out important
11 information to keep the monthly net metering impacts
12 in perspective.

13 In 2021, Georgia Power reported having
14 2.3 million residential customers with average
15 residential consumption of 12,220 kilowatt-hours per
16 year and an average residential rate of 12 cents per
17 kilowatt-hour. Based on these, the residential
18 revenues can be calculated as roughly \$3.47 billion.

19 The 5,000 monthly net metered customers
20 represent 2/10 of 1 percent's of this residential
21 customer base. The annual impact of monthly netting
22 for which the company is requesting a rate adjustment
23 to be borne by all customers is \$1.24 million per
24 year.

25 It's inappropriate for the company to request

1 this rate adjustment to offset the reduced
2 consumption from the subset of customers who have
3 invested in distributed solar. However, even if the
4 company's argument and calculation of \$1.42 million
5 are taken on their face value, then the impact per
6 customer is 62 cents per residential customer per
7 year. The total impact on the residential revenues
8 is 4/100 of 1 percent.

9 Georgia's net metering has been an early
10 success and could grow to more than five times before
11 reaching the national average of 1.1 percent
12 customers with -- with distributed rooftop solar.

13 The company's proposal to terminate net
14 metering is premature and based on arguments that do
15 not place the impacts in context. I cite national
16 research indicating that even if net metering in
17 Georgia continues to grow through 2030, the impacts
18 on rates will be small compared to other contributing
19 factors.

20 My analysis and the company's testimony both
21 indicate that ending monthly net metering
22 significantly worsens the customer economics for
23 rooftop solar. I provide an analysis indicating that
24 the simple customer payback would go from a bit over
25 12 years under the current monthly net metering to

1 almost 20 years under instant netting, and almost 32
2 years under the proposed time-of-use RD rate.

3 My analysis and the company's testimony both
4 indicate that requiring distributed generation
5 customers to take service under a three-part rate
6 will render rooftop solar entirely uneconomic.

7 The company's proposal may well be designed to
8 slow or halt the growth of distributed generation of
9 solar market in Georgia. The Commission should
10 reject such a position and direct the company to
11 enhance their consideration of distributed solar and
12 other DERs in subsequent IRP planning processes.

13 The negative impact on the customer economics
14 cited above will influence the solar investment
15 decisions for everyone, but the significant increase
16 in the expected payback period will be particularly
17 hard for low- or moderate-income households to
18 justify. Low- and moderate-income households have
19 less ability to take advantage of federal tax credits
20 that support rooftop solar. They may also face
21 barriers related to credit and financing for solar
22 installations.

23 Nevertheless, with monthly net metering in
24 place, Low- and moderate-income households have been
25 investing in rooftop solar in Georgia. The company's

1 proposal to end monthly net metering can be expected
2 to have a dramatic and negative effect on these
3 adoption trends.

4 I'm also quite concerned that the company also
5 proposes that after January 1st, 2023, all new
6 customers with distributed generation be placed on
7 the three-part rate, such as the TOU-RD rate.
8 Empirical evidence shows this rate to be regressive,
9 resulting in higher bills for the low --
10 lower-consuming customers who are more likely to be
11 Low- and moderate-income households.

12 The TOU-RD rate is also deeply flawed in design
13 with relation to the noncoincident demand charge
14 components in relation to encouraging and enabling
15 future market growth for electric vehicles and
16 battery storage.

17 With respect to the long-term planning,
18 distributed solar has an important role to play in an
19 optimal portfolio. Uneconomic coal plants are
20 continuing to operate because more generation is
21 needed in north Georgia. However, there is limited
22 land in north Georgia and building new large-scale
23 generation and transmission projects can face various
24 environmental and right-of-way challenges.

25 Meanwhile, a program that results in new

1 generation that has seen significant update,
2 including an increase among low- and moderate-income
3 households, that utilizes rooftops and that leverages
4 and stimulates significant private capital via
5 customers paying for the permitting and the
6 construction of the generating array, is not only
7 closed due to being fully subscribed, but the company
8 now suggests ending the successful program entirely.

9 When asked during cross-examination if the
10 company considered behind-the-meter resources as a
11 solution in north Georgia, the company responded with
12 concerns that the resources would not be available
13 and online when contingencies happen.

14 I will note that the company has not proposed
15 any policies or programs or incentives to encourage
16 the adoption of solar plus storage behind-the-meter,
17 which could be available and online around the clock
18 to provide the needed services. This lends further
19 weight to the conclusion that the company's proposal
20 may well be designed to suppress customer-sided
21 behind-the-meter resources.

22 If the company does not kill distributed solar
23 market growth through their ill-advised proposal to
24 end monthly net metering at this time, then the
25 forecast for distributed solar adoption is a key

1 input into the development of any IRP.

2 Most utilities often model forecasted options
3 of distributed solar and/or distributed battery
4 storage as a reduction to the energy and the peak
5 load forecast. Since these resources can reduce the
6 utility's load and potentially offset future load
7 growth and the need for new resources, it is crucial
8 that stakeholders have access to the inputs that go
9 into the development of the forecast.

10 Given the importance of distributed solar and
11 the implications that different levels of distributed
12 solar growth can have on IRP results, the company
13 should work collaboratively and transparently with
14 stakeholders to develop distributed solar forecasts
15 as input for future IRPs.

16 The company's proposed end to monthly net
17 metering is based on a faulty logic over cost
18 shifting. It's overstated based on the level of
19 current market adoption. It's unfavorable to the
20 economics for rooftop solar, and it has negative
21 equity impacts and it risks missing the customer and
22 system benefits of expanded distributed solar
23 generation as a system resource.

24 Distributed solar generation in Georgia
25 supported by net metering can play a larger role in

1 meeting the portfolio objectives, such as clean
2 energy targets, improved resilience, grid
3 flexibility, and portfolio diversification, while
4 also addressing equity issues.

5 I strongly recommend the Commission reject the
6 company's net metering proposal, except for taking
7 steps to improve customer protections and consumer
8 education, which I support. The Commission should
9 order the company to continue the monthly net
10 metering at least through the next rate cycle.

11 If a numeric cap on the number of monthly net
12 metering participants is deemed necessary, it should
13 be no less than 75,000 customers, a level that still
14 represents a relatively small share, roughly
15 2.3 percent of the residential customer base.

16 The Commission should reject the company's
17 proposal -- proposed requirement of the TOU-RD rate
18 as the default for customers with distributed
19 generation. The company should be directed to revise
20 the design of the TOU-RD rate to address serious
21 flaws, such as the undue impact on low-consuming
22 customers and the inappropriate treatment of the
23 demand charge based on noncoincident peak
24 consumption.

25 Finally, the Commission should direct the

1 company to create a work group, potentially with
2 facilitation by staff or a non-utility party, to
3 investigate, develop, and recommend the next
4 generation of mechanism to support distributed
5 generation solar in Georgia prior to the next rate
6 case.

7 This recommendation recognizes that as
8 distributed solar adoption increases well beyond
9 Georgia's current and near term levels, there is a
10 need and benefit to mechanisms beyond monthly net
11 metering.

12 Thank you for your careful consideration of
13 these important issues and I encourage you to ensure
14 in your decision that the benefits of a growing
15 distributed solar market will continue to be realized
16 in Georgia.

17 MADAM CHAIR PRIDEMORE: Questions from
18 Commissioners?

19 VICE-CHAIRMAN ECHOLS: Yes, ma'am.

20 Sir, it's good to see you tonight.

21 DR. HILL: Yes.

22 VICE-CHAIRMAN ECHOLS: Are you aware Georgia
23 Power is very involved with economic development in
24 the state of Georgia?

25 DR. HILL: Yes.

1 VICE-CHAIRMAN ECHOLS: Spending money, human
2 resources, travel, lots of effort to bring business
3 to Georgia?

4 DR. HILL: I'm aware of the importance of
5 economic development from the company's statements,
6 yes.

7 VICE-CHAIRMAN ECHOLS: You mentioned the
8 \$1.42 million of subsidy -- or cross-subsidy that --
9 the decision that this Commission made in 2019 to
10 create a net metering program that we've learned cost
11 \$1.42 million yielded quicker than we thought 5,000
12 customers that spent maybe an average of \$20,000.
13 That's \$100 million of benefit that we received from
14 \$1.42 million of Georgia Power customer investment.
15 Would you say that that's a pretty good deal?

16 That the seed money of 1.42 that generated
17 \$100 million worth of economic development, you know,
18 electricians, you know, companies that are stood up
19 to deliver, does that sound like a good deal to you?

20 DR. HILL: It does sound like a good deal.

21 VICE-CHAIRMAN ECHOLS: And if we were to take
22 the 75,000 that you mentioned and you multiply it
23 out -- if it's a \$21 million subsidy, if the numbers
24 hold, that would yield, at \$20,000 an array, about
25 \$1.5 billion worth of economic development for our

1 state?

2 DR. HILL: I'm -- yeah. I'm not doing the
3 calculations.

4 VICE-CHAIRMAN ECHOLS: Yeah.

5 DR. HILL: But, yeah, I -- I -- the --

6 VICE-CHAIRMAN ECHOLS: Does that sound like a
7 good deal to you?

8 DR. HILL: Well, I think distributed solar
9 rooftop markets have an important role to play. And
10 there are studies and support from around the country
11 that these are creating jobs and creating economic
12 activity and -- absolutely. So I think that a
13 program that supports the sustained and orderly
14 growth of rooftop solar is critically important.

15 Having something in place that's supporting
16 rooftop solar and then, as this would tend to do,
17 kicking the legs out from under it, would be
18 ill-advised from the perspective of economic
19 development.

20 VICE-CHAIRMAN ECHOLS: And we mentioned that --
21 that just about 62 cents I think you -- was that the
22 figure you said?

23 DR. HILL: It's -- that's taking their estimate
24 of the cost shift.

25 VICE-CHAIRMAN ECHOLS: Yes.

1 DR. HILL: So the cost shift -- and I -- in my
2 testimony I also discuss that the cost shift -- I
3 agree with some of your earlier comments here that
4 it's not based on the cost of service for supporting
5 this solar generation. There's a cost shift.

6 But if you're -- if you are located closer to a
7 transformer or substation than one of the other
8 commissioners, the cost to serve you might be lower
9 than it is to serve the other Commissioners who are
10 on a residential rate. And we don't make -- you
11 don't do rate making for each individual customer,
12 which this tends to -- the cost shift is -- there's a
13 socialization or an averaging of the costs across the
14 rate class. These customers have been -- have
15 invested in solar rooftop.

16 VICE-CHAIRMAN ECHOLS: And you -- with solar
17 customers -- and I have solar --

18 DR. HILL: Yep.

19 VICE-CHAIRMAN ECHOLS: -- on my home. Solar
20 customers, would you say, are pretty into the energy
21 they're being produced?

22 They're following it on their phone, they're
23 looking at it, they know kind of what their
24 contribution to the grid is, would you say?

25 DR. HILL: Some do and some don't.

1 VICE-CHAIRMAN ECHOLS: And so the --

2 DR. HILL: Yeah.

3 VICE-CHAIRMAN ECHOLS: The \$20,000 or more
4 investment that they're making as almost an
5 initiation fee to participate in this clean energy
6 economy, that's a significant investment --

7 DR. HILL: Yes.

8 VICE-CHAIRMAN ECHOLS: -- for a homeowner to
9 make. They could have bought a camper, a boat, a
10 four-wheeler, a horse.

11 DR. HILL: Yep.

12 VICE-CHAIRMAN ECHOLS: A Trans-Am. But instead
13 they chose to make an investment that actually
14 benefits their neighbors, or that benefits the grid,
15 that gives us more efficiency.

16 DR. HILL: There's a wide range of reasons that
17 people make a decision to invest in rooftop solar.
18 And I think that those are -- they will vary across.
19 I think people value the independence that they feel
20 that's important. I think people do it for
21 environmental reasons. I think people do it for
22 resilience, backup power, all those different types
23 of things. But it is a significant investment.

24 And when given the opportunity with a
25 reasonable payback, people are choosing to do that.

1 And I think that as we look, the capital that comes
2 for our electric power system doesn't have to come
3 only from Georgia Power or the utility company.
4 Consumers can also choose, and are choosing, to make
5 that type of investment and I think that that should
6 be supported.

7 VICE-CHAIRMAN ECHOLS: Now, Georgia Power
8 values customer satisfaction. You've heard that
9 today.

10 DR. HILL: Yeah.

11 VICE-CHAIRMAN ECHOLS: I mean, we all know
12 that. They get awards for that. Do you think that
13 if customers who are net metering now have their rate
14 clawed back and -- I mean, have that privilege clawed
15 back in 8 years, 10 years, 15 years, 20 years, do you
16 think that's going to increase customer satisfaction
17 for them or decrease customer satisfaction; clawing
18 back a program that they thought was going to be in
19 place, but that was taken away for whatever reason?

20 DR. HILL: It's a bit -- different customers
21 may view it --

22 VICE-CHAIRMAN ECHOLS: It's not a trick
23 question.

24 DR. HILL: No. Different customers may view it
25 different ways. I would tend to think that the

1 customers who have invested in solar think that it
2 is -- it's a good decision. And if that decision is,
3 you know, by the changing of the rules or the
4 structures under which that type of investment is no
5 longer encouraged and is kind of taken away, I think
6 that those customers would feel not favorable towards
7 that type of a decision.

8 VICE-CHAIRMAN ECHOLS: And as the Commissioner
9 that, you know, authored the motion, it certainly
10 makes me feel like that I -- if we were to do this --

11 DR. HILL: Yeah.

12 VICE-CHAIRMAN ECHOLS: -- for any amount of
13 years would make me feel like that I had authored a
14 bait-and-switch program. That I had promised
15 something, led people to believe, yeah, invest your
16 20,000, invest your 50,000, and then I'm taking it
17 away.

18 And that -- and I think that's what disappoints
19 me the most in thinking through all of this in
20 scenarios that could happen is -- is the fact that I
21 led them to believe something that, you know, is not
22 the case.

23 DR. HILL: And at this time I would also state
24 that the company's objections -- the impacts from the
25 company objections I think are overstated. If you

1 look at it in the context of the overall system and
2 costs, et cetera, people are choosing to make these
3 investments and I think that a sustained, orderly
4 development of that market, rather than that
5 stop/start type of thing, is very important.

6 VICE-CHAIRMAN ECHOLS: Thank you so much.

7 MADAM CHAIR PRIDEMORE: Any other questions
8 from Commissioners?

9 (No response.)

10 MADAM CHAIR PRIDEMORE: There we go.
11 Americans for Affordable Clean Energy.

12 MR. GALLOWAY: No questions.

13 MADAM CHAIR PRIDEMORE: ChargePoint.

14 (No response.)

15 MADAM CHAIR PRIDEMORE: I believe he is gone.
16 I'll take him off the roster.

17 Georgia Interfaith Power & Light.

18 MS. WHITFIELD: No questions.

19 MADAM CHAIR PRIDEMORE: GA Solar.

20 MR. MORELAND: No questions.

21 MADAM CHAIR PRIDEMORE: GASEIA.

22 MR. THOMASSON: No questions.

23 MADAM CHAIR PRIDEMORE: Sierra Club.

24 MS. ARIZA: No questions.

25 MADAM CHAIR PRIDEMORE: SACE and Southface.

1 MR. DOWDY: No questions.

2 MADAM CHAIR PRIDEMORE: Okay.

3 MS. STURM: No questions for MARTA.

4 MADAM CHAIR PRIDEMORE: I'm sorry I missed
5 MARTA. I'm sorry. This is a disaster at this point.

6 At this point in the day when everybody starts
7 clocking out and sending me an email that they're
8 clocking out. I'm sorry, MARTA.

9 Okay. All right. Very good. Georgia Public
10 Service Commission.

11 I'm sorry. Georgia Power Company.

12 MR. THOMAS: We didn't have any questions.

13 CROSS-EXAMINATION

14 BY MR. MARZO:

15 Q Good evening, Dr. Hill. How are you doing?

16 A Good evening. I'm well.

17 Q I just have a few questions for you this
18 evening about your testimony.

19 Now, you mentioned during your summary that the
20 company's concern with cost shifting is a selective -- I
21 think you just mentioned it's a selective objection. And I
22 think your point was because it ignores the fact that there
23 is a systemic accepted cost shifting throughout the system.

24 Is that -- is that an appropriate recitation of
25 your testimony?

1 A There's a sharing of costs throughout the
2 system, yes. It's not each individual ratepayer is paying
3 their exact costs for the -- the rates aren't set by
4 individual customers.

5 Q And so, to me, it sounds like we agree that
6 there's a cost shift, but it's your opinion that a cost
7 shift should not -- the cost shift in this case should not
8 be addressed because other cost shifts are acceptable in
9 rate making; is that -- is that your position?

10 A I think your objection to net metering --
11 monthly net metering based on a cost shift is selective
12 because there is cost sharing. We can call it cost shifting
13 or -- there's cost sharing across the rate-making process.

14 Q Now, before you testified here today, did you
15 take an opportunity to review Commissioner Shaw's motion
16 that is a motion that put this process in motion that we're
17 here today?

18 A I have not reviewed Commissioner Shaw's motion.

19 Q Okay. So are you aware that Commissioner
20 Shaw's motion sought a fair and long-term way to address
21 cost shifting?

22 A Like I said, I have not read Commissioner
23 Shaw's motion.

24 Q And, I guess, my point is: Does the Coalition
25 of Local Governments believe that a fair, long-term way to

1 address this issue is to do nothing?

2 A No. I think part of my recommendation is -- at
3 the end of my testimony, I recommend that as part of the
4 next -- during the next rate cycle, that further analysis of
5 alternatives, based on kind of a stakeholder and a working
6 group approach, would be justified. Because I think that
7 there are different ways to approach.

8 And monthly net metering, as your saturation of
9 rooftop solar grows over time to levels that are much, much,
10 much higher than what you see today here in Georgia, that
11 alternatives and the exploration of alternatives, such as
12 staff was discussing in the earlier panel, et cetera, those
13 are warranted.

14 At this time I think it would be highly
15 ill-advised and not -- I -- the objections from the company
16 I disagree with, in terms of now is the time to end monthly
17 net metering.

18 Q Wouldn't you agree, though, as Commissioner
19 Echols, I think, articulated a minute ago, a concern about
20 the 5,000 customers that are currently in this process. If
21 you were to expand that to 75,000 customers, for example,
22 and yet there is a cost-shifting issue, what you've
23 essentially done is you created a situation where you've now
24 got 75,000, or 80,000 with the 5,000 already in place, that
25 you have to deal with a cost-shifting issue; is that fair?

1 A You -- you would have a larger one. I would
2 say even at that point I don't think it would necessarily
3 dictate the end of monthly net metering, or that with
4 monthly net metering you would have an alternative that
5 stakeholders, the power company, et cetera, staff, had
6 worked on together to come up with something that would
7 provide a sustained and orderly transition for the market.

8 I'm concerned that the proposal to end it right
9 now is not based on any kind of analysis for the customer
10 economics. That would be awful under the proposed changes.
11 And so, you know, if you're trying to put a knife in the
12 heart of rooftop solar, this would do it.

13 Q And I think there is the question of not so
14 much a knife, but you mentioned earlier, and I think
15 rightfully so, Dr. Hill, you said, in response to
16 Commissioner Echols' question that if -- there are probably
17 customers who are net metering customers who do view this
18 program favorably.

19 But to the nonparticipating customers, the ones
20 who are being asked to pay for cost shifts, what they are
21 today and what they could be in the future if this program
22 were to expand, isn't it your opinion that those customers
23 would be dissatisfied if they were faced with that situation
24 of having to pay for another person's choice to install
25 solar?

1 A I think in the context of the overall rate case
2 and the levels of rate increases that are being discussed
3 and -- I don't think that the 60 cents per customer per
4 year, or about five cents per month, is putting -- that's
5 not what's distressing the other ratepayers.

6 Q Okay. Well, let me ask you --

7 A So I think that it's very small.

8 Q Okay.

9 A And I think that you may be, you know, wanting
10 to target it or call it out as something that's this large
11 rate impact when, no, it really isn't. There are other
12 things that are driving the rate impacts. It's not monthly
13 net metering.

14 Q Well, let me ask the question this way. Are
15 you aware that the company pays municipal franchise fees to
16 the cities?

17 A I wasn't directly aware of that, no.

18 Q And are you aware that that is a component of
19 the revenue requirement, including the revenue requirement
20 in this case?

21 A I wasn't aware of that, but it sounds like it
22 would be reasonable.

23 Q And I guess my question is: If the Coalition
24 of Local Governments believes that this cost shift is small,
25 and, of course, your testimony, not a legitimate concern,

1 then could the company reduce its payments to the cities for
2 franchise fees in order to cover the cost related to this
3 cost shift so other customers don't have to bear that?

4 A I'm not sure that that question is really --
5 first of all, I'm not in a position to answer that question
6 on behalf of the Coalition of Local Governments. And I
7 think that you're trying to put my testimony into a
8 different light.

9 In the context of your rate case, the cost
10 shift that we have identified and called out as caused by
11 monthly net metering is minuscule compared to some of the
12 other costs. And so it's still \$1.42 million -- and I'm not
13 going to say that -- you know, that's -- that's your math.
14 I'm not going to say that the Coalition of Local Governments
15 supports that or whatever. But if you put it in context,
16 it's a small number.

17 Q And, I guess, my point is: If the Coalition of
18 Local Governments believes that it's small and, in fact, is
19 something that, you know, we should continue to grow, then
20 one vehicle to growing it would be to reduce the franchise
21 fee payments that go to the cities that are part of the
22 coalition; correct?

23 A I disagree.

24 Q Okay. Now, in your testimony you use
25 California's solar penetration of roughly 8.5 percent as an

1 example of a state where the cost shift is being properly
2 addressed; is that correct?

3 A I don't think I said properly addressed. It's
4 being addressed. They've had -- the NEM 3.0 proceedings
5 have been going on for about two years. I think the
6 Commission is scheduled to vote in December on that.

7 Q That's right.

8 A Yeah.

9 Q That's right.

10 And you're aware that California is dealing
11 with a \$3 billion net metering cost shift problem currently;
12 correct?

13 A I'm aware that there is a cost shift problem
14 and the desire in California is to maintain sustained growth
15 in the market to encourage solar and storage and to do so in
16 a way that is -- that addresses equity issues, as well. So
17 access across the system for ratepayers to participate in
18 the market.

19 It is diametrically opposed to something that
20 -- I would say your proposal here, which is to say: Let's
21 just end monthly net metering and just the customer
22 economics will be shot to pieces, but so it goes.

23 Q And, I guess, my basic question was: You
24 understand that currently California --

25 A Has a larger cost shift --

1 Q -- has a \$3 billion cost shift problem?

2 A Absolutely. They have a much -- they have --
3 the cost shift, yes, there --

4 Q Yeah.

5 A -- is much larger. \$1.4 million versus
6 3 billion.

7 Q And we probably can expect that at one point in
8 time that was probably a tiny problem that now is a
9 \$3 billion problem?

10 A It would be interesting to look back. I would
11 guess that California's level of saturation to be similar to
12 Georgia's would have been on the order of 20 years ago.

13 Q And so are you aware also that as part of the
14 2020 Florida Commission workshop on net metering, Florida
15 utilities are projecting over \$719 million in cost shifting
16 to non-DM customers in that state?

17 A I wasn't aware of that specific number. But,
18 again, their level of solar adoption -- rooftop solar
19 adoption is much higher than it is in Georgia.

20 Q Now, are you familiar with the history of this
21 Commission as it relates to renewable development?

22 A Not specifically. I have not --

23 Q Okay.

24 A -- had the opportunity to --

25 Q So you're not aware that under the leadership

1 of this Commission, Georgia has benefited by avoiding
2 mistakes of other jurisdictions?

3 A I would -- I think commissions generally do
4 benefit from trying to avoid the mistakes from other
5 commissions or their own past history.

6 Q Okay. So when we look at --

7 A Commissions --

8 Q Okay. I'm sorry, Mr. Hill. Finish, please.

9 Dr. Hill, finish. I didn't mean to cut you
10 off.

11 A I think the decisions of commissions take into
12 the context other jurisdictions, as well as their current --
13 their own state.

14 Q Now, on page 17 of your testimony, you state
15 that: Despite challenges, low-, moderate-income households
16 have been investing in rooftop solar in Georgia; is that
17 correct?

18 A Yes.

19 Q Now, I take it that you've studied places like
20 we talked about with California and the NEM proceeding
21 that's currently ongoing.

22 MR. MARZO: And, if I could, Madam Chair, can I
23 approach the witness?

24 MADAM CHAIR PRIDEMORE: You may approach.

25 MR. MARZO: Okay.

1 DR. HILL: Thank you.

2 This is the NEM proposed decision and then --
3 okay.

4 MR. MARZO: Now, this is a big order. I'm not
5 going to ask you to read all the order.

6 Madam Chair, what I've handed to the -- to the
7 witness is a decision revising the net meter --
8 energy metering tariffs and subtariffs in the
9 California Public Utilities Commission rule-making to
10 revise the net metering tariffs in Rule-making Docket
11 20-08-020 dated November 10th, 2022.

12 I'd ask it be marked as Georgia Power
13 Exhibit 43.

14 MADAM CHAIR PRIDEMORE: So marked.

15 (The document referred to was marked for
16 identification as Georgia Power Company Exhibit 43.)

17 BY MR. MARZO:

18 Q Okay. Would you turn to page 54 of that
19 docket. And Mr. Hewitson, to short form it, gave you the
20 single page I'm going to reference you to.

21 A Yep.

22 Q And this is from the decision that is going
23 before the Commission in December. Would you mind reading
24 the highlighted area that I identified on that page.

25 A Yes. As you said, this is -- it's a 200-page

1 proposed decision is my understanding. So this is the
2 administrative law judge's proposed decision for the
3 Commission's consideration.

4 The Commission agrees that the look-back study
5 indicates that NEM 2.0 disproportionately harms low-income
6 customers not participating in the net energy metering
7 tariff. Findings in the look-back study show that NEM 2.0
8 and, thus, NEM 1.0 disproportionally benefited non-care
9 residential net energy metering customers, while all
10 customers, including those with lower incomes, must bear the
11 addition of the 82 to 91 percent of the cost of service
12 bypass by net energy metering customers. The Commission
13 finds the look-back study indicates that NEM 2.0
14 disproportionately harms low-income customers not
15 participating in the net energy meeting tariff.

16 Q And so when I look at your testimony and you
17 have different charts, I think, as part of a demonstration
18 that there has been some low-income participation in the NEM
19 in Georgia, the reality is, though, if we look at a state
20 that is advanced in NEM, we are seeing a disproportionally
21 negative impact on low-income customers who don't
22 participate in NEM programs; correct?

23 A The -- using California as a basis for
24 comparison with Georgia's solar market today is -- they are
25 quite different. They are quite different.

1 I mean, the -- the level of adoption of rooftop
2 solar in California, you know, far, far exceeds what we're
3 talking about.

4 So my point was that under monthly net
5 metering, low- and moderate-income households in Georgia
6 have been participating. And one potential option for the
7 Commission or for a working group to consider is: How would
8 you modify monthly net metering or a subsequent tariff in
9 the future to encourage low- and moderate-income households
10 to participate?

11 You know, it's possible to have an adder --
12 income-based adder for the export value for solar. This --
13 the level of cost shifting and dealing with monthly net
14 metering at some point, I don't dispute that that's a good
15 idea.

16 Georgia is nowhere near that level of market
17 development or that stage of market development. And the
18 objections are presuming that it's the same. And I think,
19 you know, the question earlier of: Looking forward, do you
20 want to prevent a problem? Yes, you do, in a timely
21 fashion.

22 But you don't want to cry wolf before there is
23 not a problem there. And there isn't a problem, in my
24 opinion, in Georgia at this time.

25 Q But if you know the wolf is coming, shouldn't

1 you buy the gun and put up the fence so you can protect your
2 family and your farm and your other cattle?

3 A I --

4 Q I mean, do you wait until the wolf gets there
5 and you say: Wow. Wolf. We need to do something about it?

6 A No. No, you don't. And I'm not recommending
7 that. I think that having an engaged conversation with
8 analysis of the way to develop a tariff -- and one of the
9 things that I think is important is the outcome of that
10 process would support the sustained, orderly development of
11 a rooftop solar market.

12 My concern -- and it may not be the company's
13 position. But my concern is that the proposed tariff is
14 designed to eliminate customers investing in rooftop solar.

15 Q And, I guess, just by -- my base point here,
16 Dr. Hill, is that -- one thing I think we can agree on with
17 the base in this conversation is we can't simply just do
18 nothing knowing that the wolf is coming?

19 A I'm not --

20 Q You've got to take lessons learned and
21 address --

22 A I'm not proposing doing nothing.

23 Q Okay.

24 A I am proposing continuing monthly net metering
25 up to at least 75,000. I'm proposing that the Commission

1 direct a working group to address a subsequent rate design
2 based on the analysis of staff and other stakeholders in the
3 company so that the market can be supported in an equitable
4 and sustained fashion going forward. Because distributed
5 solar has a role to play in the overall utility system and
6 the value it can bring to the company and to the customers.

7 So I'm not -- I'm not saying do nothing. That
8 would be -- yeah.

9 Q But part of your solution is let's grow the
10 problem first and then come up with a solution, essentially?

11 A It -- well, monthly net metering is not the
12 problem. It is a solution that was meant -- I think
13 Commissioner Echols or others would say: What was the
14 purpose of monthly net metering? It was to support the
15 development and the installation of rooftop solar in
16 Georgia.

17 It has done that. It did that rapidly.
18 Customers adopted rooftop solar. Once the pilot was put in
19 place, it was subscribed rather quickly. It was successful.

20 So it rate -- it's a solution that if you say:
21 Okay. Well, then we're just going to stick with that and
22 we're not going to change anything down the line.

23 At some point it can become a problem or we
24 should start to address and start to think about things.
25 But you're not at the point where you end it now and that

1 you've solved the solution. Or that you've even gotten the
2 right protection, the fence, the gun, whatever you need for
3 the wolf.

4 You have a more deliberate stakeholder-engaged
5 discussion about how to revise the tariff so that you'll
6 support the market going forward and then proceed along that
7 basis.

8 In the meantime, the proposal from the company
9 would damage the market, cut it off at the knees, and you'd
10 lose the benefits. And so I'm not supportive of that.

11 Q And I assume, Dr. Hill, that you don't oppose
12 learning from lessons learned in some other jurisdictions;
13 correct?

14 A No. Absolutely.

15 Q Okay.

16 A That's important.

17 MR. MARZO: All right. Thank you, Dr. Hill. I
18 appreciate your time.

19 DR. HILL: Thank you.

20 MR. MARZO: Thank you, Madam Chair.

21 COMMISSONER MCDONALD: Dr. Hill, do you suggest
22 that in the scheme of things that the energy that is
23 used for solar, as this Commission did years ago
24 through utility-scale nets, moved onto another
25 level --

1 DR. HILL: Yeah.

2 COMMISSONER MCDONALD: We certainly didn't take
3 California as the model. I'll assure you of that.

4 DR. HILL: Yeah.

5 COMMISSONER MCDONALD: But as we move forward
6 -- and this energy that we get from people, this is
7 something that President Biden can't change; isn't
8 that right?

9 I mean, he can't change the source, like he's
10 changing the energy and so many other things in this
11 nation?

12 Oil --

13 DR. HILL: He can't -- I'm not sure.

14 COMMISSONER MCDONALD: Oil? Natural gas?

15 DR. HILL: He can't change the sun?

16 COMMISSONER MCDONALD: No, he can't do that.

17 DR. HILL: Okay. Right.

18 COMMISSONER MCDONALD: That's just an
19 off-the-cuff comment.

20 DR. HILL: Okay.

21 MS. BROWN: Madam Chair, if I may redirect --

22 DR. HILL: The sun is a -- the sun is a very
23 useful resource. And it's located in an appropriate
24 siting. It's permitted. It's going to be there.
25 It's a good resource.

1 REDIRECT EXAMINATION

2 BY MS. BROWN:

3 Q Dr. Hill, were you given the full order here?

4 A Yeah, I was. This -- yeah. The proposed
5 decision.

6 Q Can you turn to page 2, the summary.

7 A Sure.

8 Q If I could have you read, it's the middle of
9 the page from where it starts with "However," to the end of
10 that paragraph.

11 A Page 2 of the summary.

12 Q "However" is about seven or eight lines down.

13 A However, the needs of the electric grid in
14 California require additional evolution of the industry.
15 Today, California's electric grid is significantly powered
16 by clean energy during the daytime hours. The peak
17 electricity demands in the late afternoon and continuing
18 into the night lead to a greater reliance on greenhouse
19 gas-emitting resources. This decision revises the net
20 energy metering tariff to improve price signals by better
21 aligning them with the electric grid's conditions, both day
22 and night.

23 The updated billing structure of the tariff is
24 designed to optimize grid use by the tariff's customers and
25 incentivize the adoption of combined solar and storage

1 systems. These changes will help meet California's climate
2 goals and increase reliability, while promoting
3 affordability across all income levels.

4 Q Thank you.

5 So does California lead with saying that their
6 changes are due to cost shifts or do they lead with the
7 facts that prices are negative in the middle of the day and
8 they have unmet needs in the evening hours?

9 A I think that they -- you know, I'm not -- I
10 have read this decision, or proposed decision. It came out
11 just recently.

12 I'm not certain how they -- exactly they lead,
13 but the -- the conditions, yes, in California during peak
14 daytime hours now, they are over-generating. And so it's
15 not a cost -- it's not based primarily on the cost shift.

16 And all of the elements that they're looking
17 at, they are explicitly trying to address equity and access
18 to solar, not saying that solar is causing income inequities
19 or causing undue cost shifts. They are actually trying to
20 promote both solar and storage, and then solar on low- and
21 moderate-income households.

22 Sorry. That was a long-winded answer.

23 Q No. It's okay. This next part should be
24 relatively rapid fire.

25 Just to clarify, California has a much higher

1 penetration of solar than Georgia?

2 A Yes.

3 Q California has had a net metering program for
4 much longer than Georgia has?

5 A Yes.

6 Q California is a bigger state?

7 A Yes.

8 Q California has burnt down multiple times?

9 A Yes.

10 Q California has gone bankrupt --

11 A Yes.

12 Q -- probably multiple times?

13 A Yes.

14 Q So would you say -- is it even fair to compare
15 this situation?

16 A I think that there are some lessons, and one of
17 them being that this did not come out -- I mean, it's a
18 214-page proposed decision that has inputs from all kinds of
19 stakeholders on how to sustainably continue to build the
20 market. Because it has value.

21 So I think that there are some lessons to be
22 learned. But saying that California has a problem today and
23 so, therefore, Georgia should adopt California's solution
24 today, which this is -- by the way, is not -- I mean, this
25 is not just an abrupt ending.

1 There are transition periods proposed in this
2 and it's a more sustained, orderly transition as opposed to
3 what I consider the company's proposal here to be.

4 Q I'm glad you mentioned avoiding mistakes.
5 Mr. Marzo asked you multiple times if we should avoid the
6 mistakes of other states. And he's talking about states
7 that really embrace solar.

8 But isn't it equally important to avoid the
9 mistakes that states like Alabama and Tennessee have made in
10 just completely shutting down solar before it ever got to
11 start?

12 A I think so.

13 MR. MARZO: Madam Chair, I would just object to
14 the characterization. I never said states that --
15 that adopt solar.

16 I said this Commission looks at other
17 jurisdictions and it avoid mistakes. And it's done
18 that over rule support. I did not name a particular
19 adoption strategy.

20 MADAM CHAIR PRIDEMORE: Sustained.

21 BY MS. BROWN:

22 Q And then just wanted to end with the idea of a
23 fair and long-term solution. Mr. Marzo asked you about
24 that, as well.

25 Was not one of your key recommendations that we

1 initiate a stakeholder proceeding that actually develops a
2 fair and long-term solution?

3 A I think it's an important policy question, and
4 I appreciate the Commission both having monthly net metering
5 pilot. I think based on the success of that pilot, you want
6 to have a thoughtful and engaged, from all the different
7 parties, process to develop any subsequent tariff and
8 structure.

9 Q Is it easier to develop a lasting structure
10 through cross-examination or is it through a process where
11 ideas can actually be presented and tested and developed
12 collaboratively?

13 A I would say the latter is probably better.

14 MS. BROWN: Okay. Thank you.

15 MADAM CHAIR PRIDEMORE: Do you have anything to
16 move in?

17 MS. BROWN: Yes, ma'am. I was going to ask to
18 have the two exhibits moved into the record and that
19 the witness be excused.

20 MADAM CHAIR PRIDEMORE: Okay. You may move
21 them into the record.

22 (Georgia Coalition of Local Governments
23 Exhibits CLG-6 and CLG-7 were admitted into
24 evidence.)

25 MADAM CHAIR PRIDEMORE: The witness may be

1 excused.

2 (Witness excused.)

3 MADAM CHAIR PRIDEMORE: All right. Any other
4 housekeeping matters?

5 (No response.)

6 MADAM CHAIR PRIDEMORE: Hearing none, see you
7 back at 9:30.

8 (Whereupon, the proceedings adjourned at 6:25
9 p.m.)

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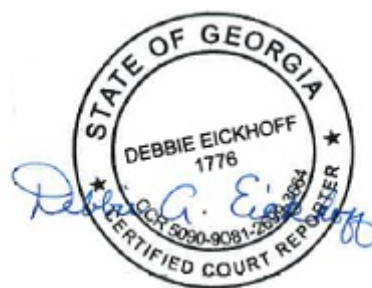
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C E R T I F I C A T E

We, Kelley Nadotti, Debbie Eickhoff and Brenda P. Elwell, Certified Court Reporters, do hereby certify that the foregoing transcript is an accurate record to the best of our abilities of the proceedings in the above-entitled matter at the time and place therein set forth.



Kelley Marie Nadotti, RPR
CCR-6256-8388-8026-4192



Debbie A. Eickhoff, RPR
CCR-5090-9084-2699-3664



Brenda P. Elwell, RPR, CRR, B-2023

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BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

STATE OF GEORGIA

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

Hearing Room 110
Georgia Public Service Commission
244 Washington Street
Atlanta, Georgia
Wednesday, November 30, 2022

The above-entitled matter came on for hearing
Pursuant to Notice at 9:30 a.m.

PRESENT WERE:
TRICIA PRIDEMORE, Madam Chair
TIM ECHOLS, Vice-Chairman
FITZ JOHNSON, Commissioner
LAUREN "BUBBA" MCDONALD, Commissioner
JASON SHAW, Commissioner

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On behalf of Georgia Interfaith Power:

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JILL KYSOR, Esquire

4

JENNIFER WHITFIELD, Esquire

Southern Environmental Law Center

5

Ten 10th Street

Suite 1050

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Atlanta, Georgia 30309

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On behalf of Georgia Solar Energy Industries
Association, Solar Energy Industries
Association, and Vote Solar:

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SCOTT THOMASSON, Esquire

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Thomasson Law, LLC

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Macon, Georgia 31201

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On behalf of Metropolitan Atlanta Rapid Transit
Authority:

13

14

KIMBERLY "KASEY" A. STURM, Esquire

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On behalf of Sierra Club:

19

ISABELLA ARIZA, Esquire

ROBERT JACKSON, Esquire

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Sierra Club

50 F. Street NW, 8th Floor

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Washington, D.C. 20001

22

23

On behalf of Cypress Creek Renewables:

24

(Appearing Remotely)

25

1 APPEARANCES (continued):

2 On behalf of Southern Alliance for Clean
3 Energy, Inc. and the Southface Energy
Institute:

4 L. CRAIG DOWDY, Esquire
5 STEVEN L. JONES, Esquire
6 Taylor English Duma LLP
1600 Parkwood Circle
Suite 200
Atlanta, Georgia 30339

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I N D E X

WITNESSES: DIRECT CROSS REDIRECT RECROSS

JUSTIN R. BARNES

By Ms. Whitfield 4588 4671
By Mr. Hewitson 4639

KENNETH SERCY

By Mr. Moreland 4679
By Mr. Marzo 4723

THATCHER YOUNG
WILL GIESE
KEVIN LUCAS

By Mr. Thomasson 4734 4885
By Ms. Brown 4867
By Mr. Hewitson 4872

Marilyn K. Brown, Ph.D.
Alden M. Hathaway, P.E.

By Mr. Dowdy 4886

Lee Evans
Larry Legg

By Mr. Hewitson 5018
By Mr. Ingraham 5049

1	EXHIBITS	FOR IDENTIFICATION	IN EVIDENCE
2	GPC:		
3	44 - Article Entitled Impact	4482	5051
4	of Inflation Reduction		
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5	45 - Errata for Lee Evans	5019	5019
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7	GIPL:		
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15	Impacts of 1% Monthly		
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17	1 - Residential Solar	4886	4886
18	Penetration by State		
19	SACE/SOUTHFACE:		
20	7 - VITA of Dr. Brown	4961	5018
21	8 - Distributed energy	4961	5018
22	generators as percentage		
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23	9 - Slow growth forecasted for	4961	5018
24	distributed solar in GA		
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25			

1	EXHIBITS (Continued)	FOR IDENTIFICATION	IN EVIDENCE
2	SACE/SOUTHFACE:		
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4	solar systems in 2019 means		
5	\$429 million in tax revenues		
6	did not come to Georgia from		
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8	11 - Residential distributed	4961	5018
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10	fees		
11	12 - CV: Alden M. Hathaway, II	4994	5018
12	13 - Tax shift of funds to	4994	5018
13	other states from GA		
14	citizens each year		
15	solar NEM is unavailable		
16			
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1 MADAM CHAIR PRIDEMORE: Good morning. Call to
2 order Docket No. 44280, Georgia Power Company's 2022
3 rate case. Let's do the list of appearances, and we
4 will take up housekeeping after public witness
5 testimony, please.

6 All right. Georgia Public Service Commission?

7 MR. THOMAS: Good morning. Preston Thomas, Dan
8 Walsh, and Griffin Ingraham on behalf of public
9 interest staff.

10 MR. HEWITSON: Good morning. Steve Hewitson,
11 Brandon Marzo, and Allison Pryor on behalf of Georgia
12 Power Company.

13 MR. GALLOWAY: Good morning, Madam Chair.
14 Newton Galloway and Terri Lyndall on behalf of AACE.

15 MADAM CHAIR PRIDEMORE: Thank you.

16 Is ChargePoint present today?

17 MR. FYKES: Good morning. Lucas Fykes on
18 behalf of ChargePoint.

19 MADAM CHAIR PRIDEMORE: Good morning,
20 Mr. Fykes.

21 Commercial Group is going to be -- have no
22 questions and just be on-line.

23 Concerned Ratepayers for Georgia?

24 (No response.)

25 MADAM CHAIR PRIDEMORE: Concerned Ratepayers

1 for Georgia?

2 (No response.)

3 MADAM CHAIR PRIDEMORE: Not present.

4 Cypress Creek Renewables? They are going to be

5 on-line as well.

6 EVgo Services?

7 (No response.)

8 MADAM CHAIR PRIDEMORE: EVgo Services?

9 (No response.)

10 MADAM CHAIR PRIDEMORE: Georgia Association of

11 Manufacturers?

12 (No response.)

13 MADAM CHAIR PRIDEMORE: I think he is just

14 going to be on-line as well.

15 Georgia Coalition of Local Governments?

16 MS. BROWN: Good morning, Madam Chair. Alicia

17 Brown on behalf of the Georgia Coalition of Local

18 Governments.

19 MADAM CHAIR PRIDEMORE: Georgia Conservation

20 Voters?

21 (No response.)

22 MADAM CHAIR PRIDEMORE: Georgia Conservation

23 Voters?

24 (No response.)

25 MADAM CHAIR PRIDEMORE: Okay. Not present.

1 Georgia Interfaith Power & Light?

2 MS. WHITFIELD: Good morning, Madam Chair.

3 Jennifer Whitfield on behalf of Georgia Interfaith

4 Power & Light.

5 MADAM CHAIR PRIDEMORE: Good morning,

6 Ms. Whitfield.

7 Georgia Solar Energy Association?

8 MR. MORELAND: Good morning. Don Moreland for

9 Georgia Solar.

10 MADAM CHAIR PRIDEMORE: Good morning,

11 Mr. Moreland.

12 Georgia Solar Energy Industries Association,

13 Solar Energy Industries Association, and Vote Solar.

14 MR. THOMASSON: Scott Thomasson for GASEIA.

15 MADAM CHAIR PRIDEMORE: Georgia Watch?

16 (No response.)

17 MADAM CHAIR PRIDEMORE: Georgia Watch?

18 (No response.)

19 MADAM CHAIR PRIDEMORE: She's not here today.

20 Interstate Gas Supply?

21 (No response.)

22 MADAM CHAIR PRIDEMORE: Interstate Gas Supply?

23 (No response.)

24 MADAM CHAIR PRIDEMORE: The Kroger Company?

25 (No response.)

1 MADAM CHAIR PRIDEMORE: Kroger?
2 (No response.)
3 MADAM CHAIR PRIDEMORE: MARTA?
4 MS. STURM: Good morning. Kasey Sturm on
5 behalf of MARTA.
6 MADAM CHAIR PRIDEMORE: Resource Supply
7 Management?
8 (No response.)
9 MADAM CHAIR PRIDEMORE: Resource Supply
10 Management?
11 (No response.)
12 MADAM CHAIR PRIDEMORE: Sierra Club?
13 MS. ARIZA: Good morning, Commissioners.
14 Isabella Ariza on behalf of the Sierra Club.
15 MADAM CHAIR PRIDEMORE: Good morning,
16 Ms. Ariza.
17 Southern Alliance for Clean Energy and
18 Southface?
19 MR. DOWDY: Good morning, Commissioners. Craig
20 Dowdy and Steven Jones on behalf of Southface and
21 SACE.
22 MADAM CHAIR PRIDEMORE: Morning, Mr. Dowdy.
23 Southern Renewable Energy Association?
24 (No response.)
25 MADAM CHAIR PRIDEMORE: Southern Renewable

1 Energy Association?

2 (No response.)

3 MADAM CHAIR PRIDEMORE: United States

4 Department of Defense and All other Federal Executive

5 Agencies? Ms. Medlyn?

6 (No response.)

7 MADAM CHAIR PRIDEMORE: Ms. Medlyn is not here

8 today.

9 Okay. Utility Management Services?

10 (No response.)

11 MADAM CHAIR PRIDEMORE: Utility Management

12 Services?

13 (No response.)

14 MADAM CHAIR PRIDEMORE: Okay. Do you represent

15 a party and I have not called your name or you have

16 not checked in present?

17 (No response.)

18 MADAM CHAIR PRIDEMORE: Okay. All right. Got

19 everybody. Sounds good.

20 All right. Let's start with our public witness

21 testimony. We have got two pages of public

22 witnesses. I will call you in the order that you

23 signed in.

24 Carlos Martinez?

25 MR. MARTINEZ: Good morning. Madam Chairman

1 and district Commissioners, I appreciate you having
2 me here, have the opportunity to talk with all of
3 you. And this present me with an opportunity to
4 share my experience as a ratepayer in relationship to
5 rooftop solar and need for net metering.

6 I am a small business owner. I am a physician.
7 I am a doctor, nephrologist to be specific. Care for
8 CKD, chronic kidney disease, and end-stage renal
9 disease, patients on dialysis. I serve the rural
10 area of Macon, Dublin, Hawkinsville, Perry, Warner
11 Robins. That's the service area. But we provide
12 mainly dialysis.

13 We adopted as individuals and as a practice
14 solar systems to our offices and our dialysis center.
15 And the reason is mostly -- most the common reasons
16 that everybody does this, which is create positive
17 impact to protect our environment, basically, which
18 is planet health, and also cost efficiency in the
19 long term and hopefully effectiveness with the
20 institution of net metering.

21 Despite those reasons which are positive, solar
22 power generates just a fraction of all utility
23 scales, 3 percent, compared to 63 generated by fossil
24 fuels. Even with the new federal solar tax credits
25 and environmental benefits, we still are at

1 3 percent.

2 What problems are we encountering? Well, this
3 is what I see as a taxpayer: That we have electric
4 utility, Georgia Power, that has a very complicated
5 rate structure that makes it very difficult to
6 understand.

7 As I try to decipher my electricity service, it
8 shows that incentivizes more the energy consumption
9 instead of energy efficiency and conservation. Most
10 Georgia Power rates are designed in energy buckets
11 where the more you consume, the cheaper it becomes.

12 Second reason that I found is that we decided
13 that elevating solar energy generation as an option
14 to reduce our grid consumption and choice of
15 renewable. For every kilowatt hour that we generate
16 it for our solar system, we only save as a fraction
17 of our average cost.

18 That means Georgia Power has a cost to us of
19 18 cents per kilowatt hour, and they receive our
20 solar energy at 2.7 cents kilowatts an hour whenever
21 there is excess generated by our system. That's
22 obviously the savings are not there, and this appears
23 to be a reverse way approach.

24 One example of our electric service bill out of
25 our solar system last month, we generated 3800

1 kilowatts that went to the grid. That's the
2 repeaters that we were not using our solar system.
3 And we received a credit of \$101.70. During the same
4 billing period, we received from the grid 2400 kWh
5 during that same period that we were not able to
6 produce energy. And we receive a bill for \$529 for
7 power. Obviously that bill encompasses also
8 environmental compliance cost. I think I heard a
9 discussion yesterday about it. And nuclear
10 construction cost recovery schedule.

11 The last time I checked that I participated on
12 paying for cost of financing, I was a shareholder.
13 That is not the case here.

14 The solution that we counter to this
15 complicated issue is that the rate structure needs to
16 be simplified and the set of circumstances that lead
17 to this incentive to make this renewable energy
18 source to become consistent with the global efforts
19 to reach carbon neutrality requires the help for the
20 Public Service Commission and bring net metering
21 back.

22 This would have to change also, that the state
23 of Georgia pioneering the efforts to achieve carbon
24 neutrality goals. I appreciate your time, and thank
25 you for the consideration of this simple and

1 complicated topic at the same time.

2 MADAM CHAIR PRIDEMORE: Happy holidays,
3 Mr. Martinez.

4 MR. MARTINEZ: Thank you.

5 MADAM CHAIR PRIDEMORE: Jennette Gayer? I'm
6 sorry. I can't read -- is it Gayer or Gyer or --

7 MS. GAYER: You know, I respond to both.

8 MADAM CHAIR PRIDEMORE: Which is it?

9 MS. GAYER: We say Gayer.

10 MADAM CHAIR PRIDEMORE: Gayer.

11 MS. GAYER: Yes.

12 MADAM CHAIR PRIDEMORE: Okay. Good morning.

13 MS. GAYER: Good morning. Thank you, Madam
14 Chair. Thank you, Commissioners, for the opportunity
15 to talk to you this morning. My name is Jennette
16 Gayer. And I am the director of Environment Georgia,
17 which is a nonprofit that works to protect Georgia's
18 air, water, and green spaces.

19 And I also serve on the Georgia Water
20 Coalition's Coal Ash Committee, which is the impetus
21 for me being here today.

22 The Georgia Water Coalition has over 200
23 nonprofits, businesses, Boy Scout troops, churches
24 that all work together to protect Georgia's beautiful
25 rivers, lakes, streams, coast, and aquifers.

1 The Water Coalition actually shared concerns in
2 the 2019 IRP and rate case that the power company,
3 without any assurances that stringent clean-up
4 techniques like liners would be used to ensure that
5 toxins and coal ash do not further contaminate
6 Georgia's groundwater, was being given permission to
7 recover huge amounts of ratepayer money.

8 Since I shared those concerns in 2019, there
9 have been several developments. The first is that
10 the cost estimate of clean-up has gone from
11 7.6 billion to nine billion.

12 The second is that the company has permitted
13 and finalized coal ash ponds that actually remove the
14 coal ash from pits in which it has contact with
15 groundwater. So that's great news.

16 But unfortunately stands by plans to leave coal
17 ash in pits that connect to groundwater at Plants
18 Scherer, McDonough, Yates, and Hammond.

19 And then the third and final thing is that the
20 EPA has issued a final decision to deny a facilities
21 request to continue disposing of coal ash into an
22 unlined surface impoundment after the deadline to
23 stop such disposal has passed. And this is the case
24 that happened in Ohio.

25 In the EPA's announcement, they noted that

1 limiting the contact between coal ash and groundwater
2 after closure is critical to minimizing releases of
3 contaminants into the environment and will help
4 ensure communities near these facilities have access
5 to safe water for drinking and recreation.

6 We know that Georgia Power's groundwater
7 monitoring data reported to the EPA reveals very high
8 levels of toxic heavy metals and more at 10 of
9 Georgia's 12 coal plants.

10 When the cleanup plans that don't require
11 liners to keep the coal ash out of groundwater fail
12 and groundwater testing continues to show
13 contamination or when the EPA comes in and requires
14 cleanup that keeps coal ash out of groundwater as
15 they have in Ohio, will ratepayers be asked to
16 contribute even more funds?

17 I know you are not environmental regulators.
18 What a thankless job; right? But you are a really
19 important watchdog. And you control the purse
20 strings.

21 So at a minimum I would ask that you not let or
22 not commit funds to cleanup that is not permitted and
23 ignores very clear signals that the EPA is sending on
24 the way that they would prefer cleanup to proceed.

25 Thank you very much for your time. Bye.

1 MADAM CHAIR PRIDEMORE: Happy holidays,
2 Ms. Gayer.

3 MS. GAYER: Thank you.

4 MADAM CHAIR PRIDEMORE: John Mote?

5 MR. MOYE: Morning, Madam Chairperson. How are
6 you? Commissioners, good morning. My name is John
7 Moye. I am senior director for policy at the Urban
8 League of Greater Atlanta.

9 Madam Chairperson, as a civil rights and
10 economic empowerment and mobility organization, the
11 Urban League of Greater Atlanta advocates for equity
12 and fairness in all matters that affect the economic
13 well-being of our families, small businesses, and
14 communities we serve.

15 Particularly now in the midst of the continuing
16 impact of COVID, rising housing and food prices, and
17 a widening wealth gap, the League is focused on
18 advocacy for regulations, policies and legislation
19 that create pathways to reducing monthly cost of
20 living for low to moderate income households, such as
21 is the case with Georgia Power's current practice of
22 net metering via regulation and partnerships with the
23 Georgia Public Service Commission to promote solar
24 energy investments.

25 As we understand it, net metering is the

1 practice of compensating or crediting solar panel
2 customers at the full retail rate for the electricity
3 that their solar panels produce.

4 This effectively forces utilities to buy back
5 the rooftop solar power produced at the retail rate
6 rather than the much lower wholesale rate paid to
7 pass -- paid to mass electricity producers.

8 The wholesale rate reflects the generation
9 costs typically paid to third-party generators or the
10 production costs paid by vertically integrated
11 utility. Notably, metering policy requires the
12 utility to buy excess solar power at an above-market
13 rates.

14 The Urban League of Greater Atlanta's concern
15 is that net metering appears to be regressive in that
16 it disproportionately benefits high-income customers
17 who can afford solar panel installation and
18 disproportionately places the burden on low-income
19 and nonsolar-adopter customers, because currently
20 Georgia Power is compensating solar customers at the
21 retail rate versus the wholesale rate.

22 In fact, according to the Center for Growth and
23 Opportunity at the University of Utah, paying the
24 retail rate for the electricity that rooftop solar
25 panels feed onto the grid shifts costs from solar

1 adopters to nonsolar adopters, since the wealthy are
2 much more likely to adopt solar than the underserved.

3 Net metering often, in our opinion, has a
4 reverse Robin Hood effect. In other words, the
5 current net metering subsidy program reduces the bill
6 for solar customers while escalating the costs for
7 the majority of utility customers who do not have the
8 means to install solar panels.

9 These include apartment renters who don't own
10 their own rooftop or people on lower or fixed
11 incomes, many representing cost-burdened households
12 who do not have the room in their budget for the
13 initial outlay to purchase solar panels for their
14 homes. They can't make the money on the back end
15 when they don't have it on the front end.

16 According to the Urban League of Greater
17 Atlanta -- accordingly, we support Georgia Power's
18 efforts to remedy this inequity by ending or
19 modifying the net metering practice to alleviate the
20 disproportionate burden on low to moderate income
21 households that are currently subsidizing wealthy
22 adopted households.

23 Madam Chairperson, I want to certainly thank
24 you for the opportunity to talk to y'all today, and I
25 certainly hope that y'all have a great day. Thank

1 you.

2 MADAM CHAIR PRIDEMORE: You, too. I am sorry,

3 I said your name is Mr. Mote. It is Mr. Moyer.

4 MR. MOYER: Moyer. Rhymes with "boy," only with

5 an "M."

6 MADAM CHAIR PRIDEMORE: You can come in here

7 with that message any day as far as I am concerned.

8 So thank you, Mr. Moyer.

9 MR. MOYER: All right. Thank you, Madam

10 Chairperson.

11 MADAM CHAIR PRIDEMORE: Happy holidays.

12 MR. MOYER: Happy holidays.

13 MADAM CHAIR PRIDEMORE: Anne

14 Mellinger-Birdsong? What a beautiful name.

15 MS. MELLINGER-BIRDSONG: Hi, my name is Anne

16 Mellinger-Birdsong. I am a pediatrician and a public

17 health specialist. I am speaking today about health.

18 And you might ask, what does the PSC, and especially

19 electricity rates, have to do with health? But in

20 fact they do.

21 Our governments at the municipal, state, and

22 federal level have their budget programs in what

23 could be called silos where we have one pot of money,

24 and one department deals with energy. Another one

25 deals with banking and the economy. A third one

1 deals with transportation. And another one with
2 health services and that department.

3 But in real life, these things are not
4 separate. How we produce power, what rates we
5 charge, how we structure our transportation system
6 are all examples of things that profoundly affect
7 health but are in different silos.

8 The rate increase that Georgia Power is
9 requesting for this year combined with the
10 anticipated requests in coming years will have major
11 impacts on families across Georgia.

12 Families whose children have asthma and need
13 electricity to power a nebulizer for their child.
14 Families whose children have diabetes and need
15 electricity for their refrigerator to store insulin.
16 Families whose children have been released from the
17 NICU and need electricity for a heart rate monitor.

18 We also know that increasing the electric rate
19 so drastically could further impoverish families
20 leading to worse health outcomes for the children,
21 because health is directly tied to income level.

22 Will these families have to choose between food
23 and keeping their child alive? Will they have time
24 to get a medical exemption for their child before
25 they are disconnected from electricity? Will they

1 space out their child's asthma or diabetes medicine
2 in order to pay the electric bill, leading to their
3 child being in the hospital or perhaps the ICU?

4 These are all things that could happen because
5 of such major increases in electric bills. The rate
6 increases Georgia Power is requesting are too severe
7 and will hurt families all across Georgia.

8 Children do not choose where they live, where
9 they go to school, or whether the air they breathe is
10 clean and healthy. Adults make these decisions for
11 them, both adults in their families and adults who
12 make policy that affect their lives.

13 What the PSC decides today and the coming month
14 about Georgia Power's rate increase will have
15 profound impacts on the health of children in
16 Georgia.

17 In addition, both net metering and the Make
18 Ready program should be expanded. Both of these
19 programs allow more clean energy and clean
20 transportation, which will, again, improve health,
21 especially children's health.

22 The more clean school buses there are, the
23 better children do in school and on their fitness
24 ground, the aerobic park. The more clean electric
25 vehicles there are on the road, the better health is

1 for everyone, especially children.

2 The more rooftop solar there is, the less air
3 pollution there is, and for those who have solar, it
4 makes life after a hurricane more stable and
5 resilient. Thank you.

6 MADAM CHAIR PRIDEMORE: Thank you, ma'am.
7 Happy holidays.

8 MS. MELLINGER-BIRDSOING: Thank you.

9 MADAM CHAIR PRIDEMORE: John Burkhardt?

10 MR. BURKHARDT: Good morning.

11 MADAM CHAIR PRIDEMORE: Good morning.

12 MR. BURKHARDT: My name is John Burkhardt. I
13 lead the Earth Ministry at my church in Roswell. We
14 are the Unitarian Universalists of Metro Atlanta
15 North. We are a smaller congregation, but we are
16 very active in serving our local community.

17 Our sanctuary roof receives bright,
18 unobstructed sunlight all day. After much time,
19 effort and fundraising, we have installed a solar
20 array on our roof. It was completed last month in
21 October.

22 I am proud to report that we are well on our
23 way to electrifying our congregation. We have
24 already replaced one furnace with an extremely
25 efficient electric heat pump. This has allowed us to

1 turn off gas service to one of our two buildings.
2 Soon the other furnace will be replaced, and we will
3 be fully electric.

4 We are doing other efficiency projects like
5 upgrading our insulation. The handful of electric
6 cars in our lot each Sunday grows larger and larger.

7 About those panels, they are working great so
8 far. We have solar-powered sermons. However, the
9 extra energy created by our panels that we cannot use
10 is sent back to the grid for free. This is because
11 currently the net metering program is limited to
12 5,000 seats, and they are all full.

13 Georgia Power has over 2.6 million customers.
14 Georgia Power provides great service. Power is
15 always on. And on that rare day when my neighborhood
16 loses power, it is back on very quickly.

17 I understand Georgia Power cannot offer us the
18 market rate or the retail rate for the net metering
19 customers. And I feel it is fair for us to receive a
20 lower rate for what we sell back, but we should get
21 something.

22 A lot of people have gone further than they
23 thought they could because someone else thought they
24 could. I am here today to request that the committee
25 require Georgia Power to expand its net metering

1 program. How about 5,000 new seats each year for the
2 next five years?

3 We appreciate the prospect of being entirely
4 fueled by Georgia Power with Georgia Power. Our
5 congregation is excited that the energy we send back
6 to the grid is used in our community instead of some
7 power produced with coal or gas sourced outside of
8 Georgia. Our panels were installed by a hard-working
9 company in our local community.

10 We are calling for energy policies that source
11 fuel from Georgia, create local jobs, and reduce
12 pollution entering our waterways.

13 Reductions on our church expenses are
14 reinvested in our community. We urge you to compel
15 Georgia Power to expand this already successful net
16 metering program to give more families, schools, and
17 churches throughout the state the opportunity to go
18 solar.

19 I appreciate the work all you do, as a
20 ratepayer and citizen of Georgia. Thank you for your
21 time.

22 MADAM CHAIR PRIDEMORE: Mr. Burkhardt?

23 MR. BURKHARDT: Yes.

24 MADAM CHAIR PRIDEMORE: You mentioned that your
25 church is in East Cobb.

1 You are served by Georgia Power and not
2 Cobb EMC?

3 MR. BURKHARDT: We are in Roswell.

4 MADAM CHAIR PRIDEMORE: You are in Roswell?

5 MR. BURKHARDT: Yes.

6 MADAM CHAIR PRIDEMORE: Okay. All right. And
7 you know that you have the ability to sign up for
8 instantaneous netting. So if you have questions
9 about that, you can -- you are not going to be left
10 with nothing on your rooftop solar. They have a
11 program that's in place.

12 So you could talk with one of the people from
13 Georgia Power that are here, and they can give you
14 the information on that.

15 MR. BURKHARDT: Okay. Thank you very much.

16 MADAM CHAIR PRIDEMORE: Sheila Jones?

17 MS. JONES: Good morning. I am state
18 representative Sheila Jones, and I want to say good
19 morning to everyone.

20 MADAM CHAIR PRIDEMORE: Good morning.

21 MS. JONES: I was elected to represent
22 District 60, the city of Atlanta and the city of
23 South Fulton.

24 I stand before you this morning, asking that
25 you hear our pleas and don't raise our monthly bills.

1 This \$16-a-month rate increase may be something that
2 each of you can afford, but many households, and mine
3 included, cannot afford this huge increase.

4 \$16 may not sound like a lot, but it is a lot.
5 And if you can negotiate, maybe \$6 or something
6 lower, something maybe that we can afford, we would
7 appreciate that.

8 Currently my office is assisting people,
9 helping them to stay into their homes. Many of them
10 have received eviction notices for various reasons,
11 and others are calling my office because they need
12 help paying their utilities.

13 For those residents who somehow manage to pay
14 their rent and keep a roof over their head, they
15 should not have this additional worry about how they
16 are going to pay this monthly rate hike. They should
17 not have to worry about whether or not their
18 electricity will be shut off.

19 This request to raise our monthly bill won't
20 stop here. This request is just the beginning. With
21 your help, this can -- this request and this proposed
22 amount can be stopped or it can be reduced.

23 I ask that you think about the people that have
24 come before you, think about the people like me and
25 the others who will not be able to afford this huge

1 rate increase. Thank you very much.

2 MADAM CHAIR PRIDEMORE: Thank you,
3 Representative Jones.

4 I know that Representative Elect Naghise has my
5 contact information. Hi, Tish. Tom Krause, who is
6 our PIO, if you would get with him in the hall, he
7 will give you my contact information as well as his.
8 We have a variety of programs this Commission has
9 approved. We can help your constituents

10 MS. JONES: Okay. Thank you.

11 MADAM CHAIR PRIDEMORE: You are welcome.
12 Erik Fleming?

13 MR. FLEMING: Madam Chair, members of the
14 Commission, ladies and gentlemen, good morning.

15 MADAM CHAIR PRIDEMORE: Good morning.

16 MR. FLEMING: My name is Erik Fleming. I am a
17 former state representative from the great state of
18 Mississippi. I am now a resident of Sandy Springs,
19 Georgia.

20 I am sure that it may come as a surprise to the
21 commissioners that someone from Sandy Springs would
22 be concerned about a rate hike, since the median
23 income in that city is around \$51,218.

24 However, at that level of income, with the
25 current rate of inflation at 7.7 percent, a

1 12 percent rate increase going into effect as
2 consumers recover financially from the holiday season
3 will be painfully felt, even in Sandy Springs.

4 Mr. Abramovitz -- and forgive me if I
5 mispronounce your name, sir. Mr. Abramovitz in his
6 testimony yesterday stated that Georgia Power is a
7 capital-intensive business. He said that to
8 emphasize that they need massive capital to repair
9 infrastructure they admittedly have neglected to
10 update for 70 years.

11 Yet from 2013 to 2021 alone, they had seven
12 years where they received over \$1.1 billion in
13 profits.

14 Now, I don't know which return on equity
15 strategy they use, whether it is substantial growth
16 model or the Dupont formula. I do know that bottom
17 line they don't want to incur any more debt to do the
18 repairs to the power grid infrastructure, nor do they
19 want to come up short with their shareholders on
20 expected dividends. That is why we are here before
21 the Public Service Commission.

22 Now, the Commission cannot do anything when it
23 comes to how much we pay for butter and bread. But
24 the Commission can reject this current proposed rate
25 hike. A 12 percent rate hike could prove to be

1 devastating to Georgia families.

2 I don't believe Georgia families should go into
3 debt so that Georgia Power doesn't increase their
4 debt service.

5 And while Georgia Power and their parent
6 company, the Southern Company, should always be
7 recognized for their charitable work in the state,
8 the most charitable thing they can do now is stop
9 pursuing this rate hike on its valued customers.

10 Again, I urge the Commission to vote against
11 the rate hike and to cap the return on equity at the
12 recommended 9.5 percent. Thank you and happy
13 holidays.

14 MADAM CHAIR PRIDEMORE: Happy holidays,
15 Mr. Fleming.

16 Mykal McFarland?

17 MR. McFARLAND: All right. Good morning.

18 MADAM CHAIR PRIDEMORE: Good morning.

19 MR. McFARLAND: First, I would like to say
20 thanks to everyone for coming out. There is a lot of
21 people that aren't reflected here that are pay
22 raters, about one in five Georgians are pay rate.

23 But when you look around here, you see a lot of
24 people nicely dressed, a lot of people that don't
25 have any obvious signs of their financial troubles

1 that they are wearing every single day.

2 Now, this pay rate will definitely affect
3 people that are already struggling with inflation.
4 You have people that are already coming up here and
5 telling about how it is going to increase the
6 inequality in Georgia, how it is going to make people
7 that are struggling with these issues, like a veteran
8 coming back that now requires medical equipment
9 constantly in order for them to have a good quality
10 of life, a mother with two children and two jobs
11 that's not able to come here and be heard. She is
12 already struggling with the inflation, with the
13 increased costs of living. And now we are talking
14 about putting more onto that.

15 I heard a lady talking about 2019, about how
16 the ratepayers had to -- had the bill passed on to
17 them, the cost of coal practices that Georgia Power
18 decided to do as a private company, an established
19 regulated monopoly in our state.

20 They decided to do certain policies that ended
21 up costing them, but then they go: Hey, we need to
22 make those profits. That year alone, 2019, the
23 CEO -- I remember we talked about this -- they had
24 \$27 million in compensation in 2019.

25 When we are talking about the increased rate,

1 what it is actually going to cost Georgia, the
2 ratepayers, we are talking about \$2.8 billion.
3 That's what they make in profits in the first
4 six months.

5 So this is a well-off company that
6 unfortunately -- I know, Bubba, you got appointed,
7 20 years, great job holding your seat. You do say
8 that -- you push for solar. You say that you are a
9 fighter for the ratepayers. We need you in this
10 fight.

11 Tim, I know that you are very involved with
12 TeenPact. You believe in Christian values. We need
13 you in this fight.

14 Republicans have to stand up with this
15 regulated monopoly and say enough is enough strain on
16 our regular Georgian citizens. And that's what I am
17 asking for all of you today.

18 Thank you very much.

19 MADAM CHAIR PRIDEMORE: Happy holidays,
20 Mr. McFarland.

21 Nina Dutton? Ms. Dutton, before you speak, I
22 am going to ask you to straighten the neck of the
23 microphone for us. Make it straight. There you go.
24 Thank you. Stop getting so much feedback then.

25 MS. DUTTON: Thank you. I am sorry?

1 MADAM CHAIR PRIDEMORE: That's good.

2 MS. DUTTON: Great. Good morning. My name is
3 Nina Dutton, and I am an Atlanta resident. I stand
4 before you today in the center of a city of extreme
5 inequality.

6 The AJC just reported this week that Atlanta
7 has the highest income inequality among large U.S.
8 cities.

9 So while the rate hikes Georgia Power is
10 proposing may not seem like a big deal for some,
11 please know there are thousands of people in this
12 city, as well as thousands more across Georgia, for
13 whom rate hikes will be a serious problem.

14 In Atlanta, the average energy burden for
15 majority Black census tracts is 4.2 percent, and
16 3 percent for all census tracts, with this difference
17 reflecting effects of a long history of
18 discrimination, red-lining, and other forms of
19 oppression.

20 6 percent of income is considered the maximum
21 affordable amount for energy bills. So for
22 households already at more than 4 percent, raising
23 the rates higher will be too much to afford.

24 Keep in mind, Georgia Power is asking you to
25 approve now a 12-percent rate increase on the average

1 residential household by 2025.

2 But I read that they plan to make further
3 revenue requests that could raise our bills by
4 45 percent over the next couple of years.

5 I don't know about you, but most people are not
6 expecting a 45-percent raise in the next couple of
7 years.

8 Let's be clear, keeping the electricity on can
9 be a matter of life and death when we are talking
10 about preventing heat-related deaths for elders in
11 the summer or people deciding whether to forego
12 medical treatment to pay for utilities. You
13 literally have the power to prevent needless
14 suffering by saying no to the rate hikes.

15 And what would these rate hikes be for? Some
16 of our money would go toward cleaning up coal ash
17 Georgia Power made by burning coal long after it was
18 already clear neither our lungs nor our rivers nor
19 our atmosphere nor our wallets can bear it.

20 After having unwisely stored coal ash in
21 unlined ponds, the least Georgia Power can do now is
22 to clean it up. But they have the audacity to make
23 us pay for dealing with their coal ash that's posing
24 hazards to our environment and our health. Talk
25 about adding insult to injury.

1 Why must we keep paying for Georgia Power's
2 mistakes? It is time Georgia Power put some of the
3 extremely high profits Southern Company reported this
4 summer toward addressing these mistakes instead.

5 In the current rate case, Georgia Power is
6 seeking to raise its return on equity again, this
7 time to 11 percent. They will go on about their
8 so-called need to satisfy their investors, but do you
9 know what I truly need? What do people in and
10 outside of this room need? What you, your
11 grandchildren, even the grandchildren of Georgia
12 Power's investors need?

13 What we need is clean air, clean water, and
14 clean energy that's generated and distributed and
15 cleaned up after as equitably as possible.

16 I ask you to stop giving Georgia Power a blank
17 check to pollute our communities and then charge us
18 for it. I ask you to lift the 5,000 household cap on
19 net metering benefits and support electric vehicle
20 infrastructure that will ensure underserved
21 neighborhoods and rural communities have access to
22 charging stations and not require ratepayers to pay
23 for coal ash cleanup at all.

24 If we do have to pay, it should only be for the
25 safest option: Full excavation and removal to lined

1 landfills. You have options here.

2 Don't pass the buck and say your hands are tied
3 and that your only option is to just pass along to us
4 the cost incurred by every bad decision Georgia Power
5 makes.

6 You are tasked with protecting the public from
7 the sheer unchecked greed and recklessness that a
8 monopoly company is incentivized to exhibit while on
9 the path of maximizing return for investors. You
10 have the option to do your job and serve the public.
11 Thank you.

12 MADAM CHAIR PRIDEMORE: Happy holidays,
13 Ms. Dutton.

14 Sonali Saindane?

15 MS. SAINDANE: Dear Public Service
16 Commissioners, my name is Sonali Saindane. Thank you
17 for letting me speak.

18 I am a city of Decatur resident. One of
19 Decatur's top priorities is to transition to
20 100 percent clean and renewable energy.

21 Your decisions will impact whether my city and
22 other cities across the state will be able to meet
23 our clean energy goals and whether Georgia Power will
24 meet its clean energy goals. Not meeting the goals
25 will have serious long-term implications.

1 Please extend the net metering program without
2 a cap. This will help our businesses, schools, and
3 citizens to afford solar on their rooftops and fuel
4 our transition to clean energy.

5 The world-wide scientific community says that
6 failing to reduce heat-trapping emissions would lead
7 to a staggering expansion of dangerous heat. We have
8 precious little time to substantially reduce
9 emissions in order to limit future warming. We must
10 do our part, including Georgia Power.

11 Historically from 1971 through 2000, Fulton
12 County averaged about 20 days with a heat index over
13 90 each year. We continue our current emission -- if
14 we continue our current emissions trajectory, by 2050
15 it is expected that the county will experience more
16 than 90 such days a year.

17 Five days with a heat index above 100 will turn
18 into 44 with a heat index over 100. One day of
19 extreme heat with temperatures of over 105 will turn
20 into 44 days with a heat index over 105.

21 The Commission has mentioned the single mother
22 on a low income at least a couple of times now.
23 Well, how would this impact her? If we continue the
24 status quo, then all of us will be paying more to
25 turn on our air-conditioners, obviously, but

1 especially the single mother on a fixed income, who
2 is likely to live in a location that will be hotter
3 due to the heat island effect.

4 We would be punishing our most at-risk
5 population long term. Is this what we want? Is this
6 what you want? Your decisions today will impact how
7 we live out our lives tomorrow and for our future
8 generations, especially the vulnerable ratepayer.
9 Thank you.

10 MADAM CHAIR PRIDEMORE: Happy holidays,
11 Ms. Saindane.

12 Jane Lindeman?

13 MS. LINDEMAN: Good morning, Commissioners. I
14 am asking you to expand the net metering cap without
15 a limit in order to greatly increase the amount of
16 rooftop solar installations in our state and lead to
17 many positive benefits for our taxpayers.

18 Georgia Power's overreliance on fossil fuels is
19 costing us a lot of money. Coal is incredibly
20 expensive. I am happy to see that they are shutting
21 down many of their plants. But Georgia Power needs
22 to skip building natural gas infrastructure in order
23 to replace the coal capacity.

24 The gas plants are expensive to build. The
25 price of gas is unpredictable. And natural gas is

1 contributing to climate change.

2 Gas is an inherently volatile resource, and
3 there is no price stability, as we all know. Gas
4 might be cheap now, but it is not going to be cheap
5 in the future.

6 We are already seeing the price of natural gas
7 spike as we reach the winter months. Across the
8 country, the average U.S. household that heats
9 primarily with gas spends -- will spend this year
10 28 percent more than it was a year ago and 62 percent
11 more than it was two years ago.

12 Natural gas doesn't do anything but send money
13 out of state. Gas is fracked out of state, and
14 that's piped in. We talk a lot about valuing energy
15 independence, but we also talk about energy
16 independence that applies to our local and state
17 economies.

18 Georgia ranks 43rd in the U.S. for residential
19 rooftop solar penetration. Not surprisingly, Georgia
20 and Kansas have the unfortunate distinction of being
21 tied last -- let me restate that -- being tied for
22 last place as being the least supportive of rooftop
23 solar policies. The rooftop solar industry in
24 Georgia has seen a downturn since the net metering
25 cap was met.

1 By expanding the net metering without a cap, we
2 would get all the savings on our energy bills plus
3 boost our state's economy and create good-paying
4 jobs.

5 Finally, climate change impacts our current and
6 future rates. Climate change directly contributes to
7 increased electricity demand. Increased demand
8 drives up our rates. The more heat days we have, the
9 more air-conditioning we need, obviously, and the
10 rates increase.

11 I want to be clear. I understand that some
12 rate increases might be necessary to pay for the
13 transition to clean energy. I support spending some
14 money to modernize our grid and the transportation
15 systems in order to get more solar.

16 We don't want -- what we don't want is for
17 Georgia Power's overreliance on fossil fuels. We
18 want to pay for Georgia Power to upgrade the grid and
19 get renewable energy connected to where it is needed
20 most. Therefore, I am asking you to expand the net
21 metering program without a cap. And thank you.

22 MADAM CHAIR PRIDEMORE: Happy holidays,
23 Ms. Lindeman.

24 Lisa Coronado?

25 MS. CORONADO: Good morning, Commissioners.

1 Georgia Power's main argument against expanding its
2 net metering program has been that it has led to a
3 cost shift to those not in the program.

4 How much is that cost shift? Using the
5 company's numbers, that amount currently turns out to
6 be in the range of two to five cents a month,
7 pennies.

8 Even if the net metering program was increased
9 fifteenfold, that would still only be 30 to 75 cents
10 per month.

11 It is hard to buy Georgia Power's professed
12 worry for ratepayers over such a negligible amount,
13 especially when compared to the significantly larger
14 monthly rate increases they are asking for.

15 And national polls have for more than 20 years
16 found majority preference for renewable energy over
17 other energy sources.

18 A study by the DOE found that people are
19 willing to pay for it. 70 percent are willing to pay
20 at least five extra dollars per month for renewables
21 over fossil fuels. 38 percent at least \$10 more, and
22 21 percent at least \$15 more.

23 So it seems reasonable that most people would
24 be happy to pay 30 to 75 cents per month to
25 contribute to adding renewable energy to the grid,

1 especially if they understood that
2 generating efficient -- generating energy on rooftops
3 right where it is used is super-efficient and reduces
4 transmission and distribution costs across the
5 system, which brings me to my next point.

6 There may not even be a cost shift. Georgia
7 Power did not provide the cost basis data analysis
8 directly requested by the Commission.

9 There are credible arguments that there is a
10 net benefit, a cost savings to all ratepayers from
11 rooftop solar under the net metering plan.

12 Our need to rapidly expand renewable energy is
13 critical, primarily because fossil fuel companies and
14 utilities have spent vast amounts of money to deny
15 the climate science and slow government climate
16 action.

17 A recent report, Southern Company Knew, details
18 how Southern Company played a leading role in the
19 spreading of climate disinformation since the late
20 1980s despite understanding the devastating climate
21 impacts.

22 Now, Southern Company has stated clean energy
23 goals. Georgia Power has spent ratepayer money on
24 expensive ads promoting its commitment to
25 sustainability. And that's because in a world where

1 climate-fueled extreme weather events are occurring
2 with ever-increasing frequency and magnitude, the
3 public is demanding action.

4 The problem is Southern Company and Georgia
5 Power aren't close to taking enough action. They are
6 nowhere near on the pathway to meeting stated clean
7 energy goals. They received an F for their efforts
8 from the Sierra Club.

9 You have the authority to make Georgia Power do
10 more than lip service. They need to rapidly ramp up
11 their renewable energy sourcing.

12 Georgia is currently ranked 43rd in the U.S.
13 for rooftop solar penetration, not surprising given
14 that a recent analysis shows that Georgia is tied
15 with Kansas as having policies that are least
16 supportive of rooftop solar.

17 Monthly net metering has been an often adopted
18 and successful mechanism for promoting solar during
19 the early stages of market development.

20 We can only move forward with the right
21 policies. I encourage you to listen to the
22 intervenors and to expand the net metering program
23 without a path through the next rate cycle. Thank
24 you and happy holidays

25 MADAM CHAIR PRIDEMORE: Happy holidays,

1 Ms. Coronado.

2 Scott Presson?

3 MR. PRESSON: Good morning. Good morning,
4 Madam Chairwoman and Commissioners.

5 MADAM CHAIR PRIDEMORE: Good morning.

6 MR. PRESSON: I am Dr. Scott Presson from
7 Lawrenceville, Georgia, and I am very concerned for
8 the citizens of Georgia about the hardships the
9 potential rate increases being proposed will bring.

10 I would ask that the rate increase and rate of
11 return be looked at and reduced. One action that may
12 help in the process is through the Infrastructure
13 Investment and Jobs Act, or the IIJA, and the
14 Inflation Reduction Act, or IRA, and other federal
15 legislation.

16 I ask that the Commission and Georgia Power
17 seek to maximize the benefits to the company, the
18 Commission, the state, and the customers from the
19 numerous programs in this new legislation.

20 The potential benefits contained in it are
21 enormous. Making optimal use of these programs will
22 accelerate our just transition away from fossil fuels
23 to renewable energy and to a more resilient,
24 efficient transmission and distribution system while
25 minimizing rate increases.

1 Disadvantaged energy-burdened families and
2 communities are a priority for assistance in many of
3 these programs.

4 Now, the benefits and savings from these
5 programs extend into the future with additional
6 savings from avoided health care costs, improved air
7 quality, and a more stable climate. Scientists are
8 telling us we need urgent action beginning now,
9 through this decade, and on.

10 As this legislation is only now being
11 implemented, the Commission should maybe consider
12 rate adjustments on a yearly basis during this
13 period, as both the company and the Commission has a
14 closer look at the costs and savings from these
15 programs over time.

16 Georgia should take full advantage of the IIJA
17 and IRA programs to the benefit of our state and
18 local governments, electricity providers, our
19 industries, businesses, and residents.

20 Thank you for the opportunity to comment this
21 morning and for your service to the people of
22 Georgia. Thank you.

23 MADAM CHAIR PRIDEMORE: Happy holidays,
24 Mr. Presson.

25 MR. PRESSON: Thank you.

1 MADAM CHAIR PRIDEMORE: Amryn Soldier?

2 MS. SOLDIER: Good morning, everyone. My name
3 is Amryn. I am a business owner. I am a born and
4 raised Atlanta resident. I moved back here after
5 going to school in North Carolina because I couldn't
6 stay away.

7 So I represent A.A.I.M.S. Montessori School in
8 Suwanee. We have been open for about ten years. We
9 are a school that serves infants all the way through
10 second grade. We have installed solar panels in our
11 building in 2019 and have been able to participate in
12 the monthly net metering program.

13 This program was essential to our participation
14 in the sustainable energy method. It was one of the
15 largest reasons we decided to invest in solar as a
16 long-term plan for our school.

17 The initial cost was not feasible for us
18 without these programs, including things such as tax
19 incentives. Almost every month our school produces
20 more energy than we expend, which is a significant
21 benefit for Georgia Power. We consume an average of
22 1,225 kilowatts per hour and produce an average of
23 1,730.

24 I strongly believe that removing programs such
25 as monthly net metering has caused a lack of interest

1 in expanding sustainable energy to other small
2 businesses such as ours.

3 Solar power is one of the most accessible forms
4 and should be treated as one of the best options for
5 businesses to contribute to furthering sustainable
6 energy.

7 On a more personal note, as a school, we
8 continue to teach students and the next generation
9 how our school is sustainably powered and what is
10 possible for the future.

11 We have invited representatives from the
12 Creative Solar Company team to speak to the students
13 and spark their own interest in solar energy and how
14 it can be a benefit for the environment and the
15 community in the long term.

16 The overall goal for an energy or utility
17 company should be first to benefit the people it
18 serves and the world as a whole. The removal of
19 these programs prioritizes profit instead of
20 actual -- the people that are being served by this
21 company.

22 As a society, our focus should be reducing our
23 energy consumption and therefore a negative impact on
24 the environment by finding more sustainable ways to
25 live. The largest barrier to all these benefits is

1 cost.

2 By supporting businesses with programs to
3 encourage participation in solar energy, each party
4 gains greatly. Georgia Power is able to have
5 multiple sources of energy on the grid that produce
6 energy for them. Businesses are able to save on
7 overhead expenses. And citizens benefit from having
8 an increased presence of sustainable energy in their
9 communities.

10 I urge you to -- encourage you to expand the
11 net metering program and continue these policies and
12 do not vote for this rate hike. Thank you so much
13 for your time.

14 MADAM CHAIR PRIDEMORE: Happy holidays,
15 Ms. Soldier.

16 MS. SOLDIER: You as well.

17 MADAM CHAIR PRIDEMORE: Cesar Prieto? Please
18 tell me that I got that right. Prieto?

19 MR. PRIETO: Prieto.

20 MADAM CHAIR PRIDEMORE: Prieto.

21 MR. PRIETO: Yep.

22 MADAM CHAIR PRIDEMORE: Prieto. Thank you,
23 sir.

24 MR. PRIETO: Prieto. Good morning, thank you
25 for the opportunity. My name is Cesar Prieto. I

1 have been in the solar industry for five years. But
2 I am not part of any board or executive team of the
3 groups being represented here. I am speaking solely
4 on my behalf as a ratepayer and as a concerned
5 citizen based on the exposure I have had to the
6 proceedings.

7 So I watched this process, and it reminds me of
8 the movies with the bad guys on one side and the
9 defendants on the other.

10 COMMISSIONER MCDONALD: Would you say that
11 again?

12 MR. PRIETO: Nothing personal. But first of
13 all, I don't think Georgia Power is the bad guy. I
14 want to make sure that's on the record. I grew up in
15 Columbia with rolling blackouts, and I think you guys
16 should make money on a service that's essential to
17 everyone that receives it.

18 So I think, you know, from that respect you
19 guys are doing a good job.

20 However, I know you are a regulated monopoly.
21 And it is normal for a company in your place to feel
22 some sense of entitlement and to feel paranoid when
23 there are new technologies that are disrupting an old
24 business model.

25 In Georgia Power's frantic attempt to

1 extinguish the birth of rooftop solar, they are using
2 the argument of cost shifting to nonsolar customers.
3 But let's keep things in context.

4 How many customers do we currently have under
5 net metering? 5,000. How many customers does
6 Georgia Power have? 2.6 million or more. And
7 counting.

8 So we are looking at 0.2 percent of that
9 customer base. Even if there is a cost shift taking
10 place, it is a rounding error on your financial
11 statements. As somebody else pointed out, there
12 might not be even a cost shift if you look at the
13 bottom line and not the top line.

14 So Georgia Power likes solar when they can own
15 it, but when you contract it directly through large
16 utility scale products -- projects. But your
17 enthusiasm wanes when those panels go behind the
18 meter, because now they are not part of their assets,
19 and they cannot use it to calculate their rates.

20 They are madly fighting not to share a tiny
21 sliver of a cake that they have on their plate when
22 at the same time you have a huge cake coming out of
23 the oven. It might burn if you don't take care of
24 it.

25 That cake is the EV revolution. It's a new

1 revenue opportunity for Georgia Power because they
2 have that infrastructure.

3 Imagine all the energy transportation fuels
4 that will be displaced by electrons. And, Georgia
5 Power, you own the infrastructure to exponentially
6 grow that piece of business. That is your fresh new
7 cake coming out of the oven. Do not obsess over the
8 sliver that you might need to share with others
9 through net metering.

10 Experience from other places in the U.S. and in
11 other countries show that rooftop solar could grow
12 more than 100-fold based on the level of penetration
13 that we have in Georgia before we really start seeing
14 issues with grid stability. So I think removing the
15 cap on net metering is the right thing to do.

16 Thank you.

17 MADAM CHAIR PRIDEMORE: Happy holidays,
18 Mr. Prieto.

19 Eddie Ehlert? Ehlert. Ehlert, is that
20 correct?

21 MR. EHLERT: Ehlert, but --

22 MADAM CHAIR PRIDEMORE: Ehlert.

23 MR. EHLERT: I am used to that. You should
24 have seen people in the dentist office when I was a
25 kid. The nurse comes out with a terrified look on

1 her face.

2 Good morning, everyone. Thank you for hearing
3 me. I am here to speak as a Georgian, as a small
4 business owner, and primarily with the concern that
5 so much of this rate case is based on the purchase
6 and consumption of hydrocarbon fuels in order to
7 generate electricity and the cost to maintain the
8 grid to remove -- to move that generated electricity
9 from the point of generation to the point of use
10 using yesterday's technology to generate today's
11 dividends off the backs of ratepayers while ignoring
12 tomorrow's bounty.

13 Ten years ago we wouldn't have even been
14 discussing solar because the cost was enormous. But
15 rooftop solar now is capable of generating
16 electricity at greater economic efficiency than any
17 sort of stranded-cost generation method and the cost
18 of maintaining the grid to move that.

19 The development of organic and perovskite sales
20 guarantee that this cost will continue to drop for
21 rooftop solar. And the Southern Company is
22 fundamentally ignoring that in this rate case and in
23 the recent IRP.

24 We have to start looking at the reality of our
25 changing environment and the need to eliminate the

1 consumption of hydrocarbon fuels as much as possible
2 for generating our vital electrical needs. We are
3 not doing that in this.

4 Secondarily, I want to express my concerns
5 about the remediation of coal ash and the fact that
6 the people who paid to buy the coal, the people who
7 paid the Southern Company to burn the coal, and the
8 people who have maintained the facilities where the
9 Southern Company dumps the coal ash should not be on
10 the hook for cleaning up and properly storing this
11 coal ash.

12 And should an incident such as that occurred in
13 the Dan River or Emory River ever occur, the Public
14 Service Commission needs to ensure that the
15 ratepayers are held free from any liability and that
16 the Southern Company absorb the costs for such an
17 error. That's all. Thank you.

18 MADAM CHAIR PRIDEMORE: Happy holidays, sir.

19 Neil Sardana?

20 MR. SARDANA: In the interests of time, I will
21 defer to other commentaries.

22 MADAM CHAIR PRIDEMORE: Okay. Happy holidays,
23 Mr. Sardana.

24 MR. SARDANA: Happy holidays.

25 MADAM CHAIR PRIDEMORE: Patty Durand?

1 MS. DURAND: Well, haven't we enjoyed some
2 really warm November temperatures? That's good
3 because we helped create it and cause it.

4 Georgia is one of the top carbon emitters in
5 the country. And for state rankings for rooftop
6 solar, as we have heard, we are in the 40s, despite
7 being the 14th sunniest state in the nation and
8 having the eighth most population. Here we are in
9 40th place due to 2019 rate case decisions and
10 continuing with the 2022 IRP.

11 I wonder how Mr. Echols' new home on
12 Tybee Island is going to fare as more frequent and
13 stronger hurricanes hit Georgia's Golden Isles and as
14 sea level rise continues to happen?

15 To prevent the worst impacts of overheating,
16 the climate heat-trapping gases must be cut in half
17 by 2050. And that is the target from the Inflation
18 Reduction Act.

19 But if we stay on the path adopted by this
20 Commission, as requested by Georgia Power, Georgia
21 will fail to contribute what is needed to that goal.

22 The Inflation Reduction Act represents the
23 single highest, largest investment to date by the
24 United States to modernize the grid. It has the
25 potential to accelerate an equitable, electrified,

1 and distributed energy future.

2 But that won't happen if this Commission
3 doesn't open -- reopen the IRP that happened earlier
4 this year and this rate case to look at the programs
5 and to reengage those programs for this state.

6 Instead of doing that, you have ignored its
7 passage and proceeded as though nothing happened at
8 the federal level.

9 According to the Energy Transition Institute,
10 they have produced a state-by-state analysis of
11 needed emission reductions, mostly accomplished by
12 curtailing combustion and fossil fuels.

13 According to ETI, Georgia is one of 15 states
14 that produced disproportionately high amounts of
15 heat-trapping gases and is one of six states that
16 fall on all three categories of their calculations,
17 highest emissions and carbon for gas burning for
18 electricity, highest emissions from coal burning for
19 electricity, and highest emissions overall.

20 To Dr. Moye's point or Mr. Moye's point about
21 net metering being a cost shift, Dr. Robert Bullard
22 is the father of environmental justice.

23 He was the first one to recognize the
24 disproportionate impacts of environmental racism
25 where pollution and climate change have stripped

1 communities of color of the right to meet their basic
2 needs.

3 If we don't stop carbon emissions -- and
4 Georgia is one of the highest emitters -- and we
5 don't do our part to reduce climate change, then
6 everyone is hurt, but disproportionately people of
7 color are hurt.

8 So I am asking this Commission to please end
9 the limit on net metering, allow rooftop solar to
10 flourish in Georgia. We are going to need hundreds
11 of the amount of -- of solar energy in this state
12 that Georgia Power wants because they only want what
13 they can profit from, to the previous speaker's
14 point. That's the only way our southern Golden Isles
15 are going to be saved. Thank you.

16 MADAM CHAIR PRIDEMORE: Happy holidays,
17 Ms. Durand.

18 David Ferris?

19 MR. FERRIS: Good morning, y'all. My name is
20 David Ferris.

21 MADAM CHAIR PRIDEMORE: Good morning.

22 MR. FERRIS: I am a utility customer of Georgia
23 Power. Families like mine can't afford a rate hike
24 on our already expensive power bills. Atlanta is the
25 second most energy-burdened city in the entire

1 country, meaning the average Atlantean pays a higher
2 percentage of their income on energy bills than most
3 people in the entire U.S.

4 We can't afford to keep paying for expensive,
5 dirty fossil fuels when cheaper, cleaner alternatives
6 are available right now.

7 What is more, Georgia Power makes bad decisions
8 with customer money. But the Georgia Public Service
9 Commission keeps giving Georgia more of it. The
10 Public Service Commission should put people over
11 Georgia Power's profits. Stop giving Georgia Power a
12 blank check to pollute our communities and then
13 charging us for it.

14 The PSC should lift the household cap on net
15 metering benefits. The PSC and Georgia Power should
16 support electric vehicle infrastructure in
17 underserved neighborhoods and rural communities. And
18 ratepayers should not have to pay to clean up coal
19 ash.

20 Georgia Power and Southern Company executives
21 make millions while every day people in Georgia
22 struggle to make ends meet.

23 Georgia Power and Southern Company only care
24 about profit. The Southern Company's stock is up
25 nearly 22 percent in the last six months, 16 percent

1 this year, and 64 percent in the last five years.

2 This company has a track record of investing
3 these profits in executive pay, investor payouts,
4 before cleaning up its own messes or investing in the
5 clean electricity infrastructure that we desperately
6 need.

7 There are many cheaper alternatives, like
8 solar, batteries, energy efficiency that could help
9 prevent or reduce the need for rate hikes. But
10 instead of investing in these cheaper options,
11 Georgia Power is doubling down on fossil fuels like
12 coal and fracked gas.

13 Georgia Power needs to swiftly transition to
14 clean energy ASAP. The PSC should do its job to
15 represent the public interest. The Commission should
16 reject the rate increase and approve the expansion of
17 net metering.

18 If you pass this rate increase, you will be
19 enabling this company's regressive focus on profit
20 and commitment to burning dirty fossil fuels, and you
21 will be passing those costs along to the most
22 burdened people who are struggling in Atlanta.

23 Georgia Power and Southern Company should
24 invest its massive profits in cleanup efforts and
25 expansion of green energy infrastructure. In other

1 words, invest in the future rather than passing the
2 bill for its mistakes and for its investor-earned
3 profits on to working families. Thank you.

4 MADAM CHAIR PRIDEMORE: Happy holidays,
5 Mr. Ferris.

6 Drew de Mar?

7 MR. DEMAN: Good morning. It is "DeMan," but I
8 apologize.

9 MADAM CHAIR PRIDEMORE: DeMan. Sorry.

10 MR. DEMAN: My chicken scratch can be pretty
11 hard to decipher at times. Good morning, Madam
12 Chair --

13 MADAM CHAIR PRIDEMORE: Good morning.

14 MR. DEMAN: -- and Commissioners. I am Drew
15 DeMan. I am a contractor and a community organizer
16 in the city of South Fulton, Georgia, just south of
17 Atlanta here. And I oppose the rate hike, and I
18 encourage y'all not to accept this rate hike.

19 It hurts families and householders. And we
20 know that at this time when inflation is high and
21 wages are not keeping up, that working people are not
22 going to be able to afford this.

23 And many people have made great points as to
24 why Georgia Power's hiked rates already during COVID
25 pandemic, hurting working class people the most.

1 They have hiked rates to cover the cost of the coal
2 ash cleanup, which other people have pointed out
3 already. We know this. It is transparent and
4 obvious, and we resent very much that we are paying
5 for this.

6 They have also hiked rates to pay for a power
7 plant that's years overdue and millions over budget.
8 Another thing that we all are angry about, and we
9 have had enough of. This is years that we have known
10 about this. Who is benefiting? Is it the CEOs or
11 the ratepayers? It doesn't feel like we are.

12 People in several states have advocated against
13 the Southern Company's heedless consumption of coal
14 against the science that we know coal is contributing
15 to destructive climate change that we are all going
16 to feel the effects of. Even the wealthy will feel
17 the effects of that.

18 We have advocated against the costly and
19 wasteful Vogtle reactor. Why should we keep paying
20 more? We see the reality. Georgia Power's
21 insistence on reckless use of coal dooms us all to
22 climate chaos. Why should we pay the company more to
23 enable this destructive practice?

24 The careless disposal of coal ash is something
25 the company should have curbed decades ago. Instead

1 of committing to clean energy, Georgia Power focused
2 on ensuring corporate profits and executive salaries.

3 The Southern Company has a long-standing
4 reputation as a major polluter and a prime example of
5 a monopolistic corporation. Inflation is high and
6 wages for workers are not keeping up. \$700,000
7 salary for CEO Michael Garrett is pretty staggering
8 considering the difference between what he makes and
9 somebody in my city makes working for -- in a
10 warehouse or working in the hospitality industry, for
11 example.

12 They have made record profits over recent years
13 and don't deserve any more of the money they can
14 squeeze from us. So I strongly urge y'all to deny
15 their request for hiking our rate. Thank you.

16 MADAM CHAIR PRIDEMORE: Happy holidays,
17 Mr. DeMan.

18 Jill Wu?

19 MS. WU: Good morning. It is nice to meet
20 y'all. My name is Jill Wu, and I am here to
21 represent my parents and other members of the Asian
22 American Pacific Islander or AAPI community in
23 Atlanta.

24 On behalf of my parents, please don't raise our
25 bill. My mom and dad are senior citizens on a fixed

1 income. They can't ask for a profit margin increase
2 like Georgia Power.

3 Can you imagine all the elders who are in
4 Georgia Power's territory asking Social Security
5 Administration, please give me an 11-percent bump in
6 my monthly payment? That would be the day.

7 And I say this because Georgia Power made
8 8.5 billion in revenue in 2021. 8.5 billion. They
9 should take on the cost of toxic coal ash cleanup and
10 Plant Vogtle's construction delays and overruns.
11 They shouldn't be passing on these costs to
12 residential ratepayers like you and me.

13 On behalf of the AAPI community, please don't
14 raise our bill. The AAPI community in Georgia faces
15 energy burden, too. We expect you to advocate for
16 us, for us to have affordable electricity. We are
17 the fastest-growing population and electorate in
18 Georgia, and we are paying attention to this rate
19 case.

20 As a board member of the Asian American
21 Advocacy Fund, a political advocacy organization, I
22 can tell you we will mobilize our community to turn
23 out for the Public Service Commission election.

24 For the AAPI community and our neighbors to
25 thrive in this economy, we do need to switch to

1 cleaner, cheaper energy options now. We don't want
2 to pay for Plant Bowen and keep paying for fossil
3 fuel generation that pollutes our air, our water and
4 soil and harms our health.

5 We want more solar batteries and energy
6 efficiency to get around or reduce the need for rate
7 hikes.

8 Georgia could be a leader in rooftop solar
9 power in the U.S. But we are behind other southeast
10 states in actual capacity installed. How can we get
11 there?

12 We could start by expanding net metering and
13 removing the cap for Georgia Power's monthly netting
14 program. You guys can help ease the existing energy
15 burden for our underserved community members by
16 making it easier and more affordable to install solar
17 and gain bill-saving benefits.

18 Please don't raise our bill. Georgia Power is
19 a billion-dollar company that shouldn't be raising
20 rates for residential customers, for seniors like my
21 parents, and members of the AAPI community.

22 You guys have the power to decide what is fair
23 and reasonable for every-day Georgians to survive and
24 even to thrive. Thank you, and happy holidays.

25 MADAM CHAIR PRIDEMORE: Happy holidays, Ms. Wu.

1 Max Brown?

2 MR. BROWN: Good morning, Madam Chairperson.
3 Good morning, Commissioners.

4 MADAM CHAIR PRIDEMORE: Good morning.

5 MR. BROWN: My comment, my concern is very
6 basic. As a citizen and as a retired teacher of 31
7 years here in Georgia in DeKalb and in Gwinnett
8 County schools, I am here to urge you to serve the
9 public.

10 As to our teachers, as to our educators, on a
11 percentage basis, these rate increases are far
12 greater than our teacher pay raises. The proposed
13 rate increase is a burden for our teachers and our
14 people in Georgia.

15 So I would urge you to reject this rate
16 increase and the many future planned rate increases.
17 They do not represent increases in service,
18 improvement in service for our people. They will be
19 a burden.

20 Thank you for listening, and happy holidays.

21 MADAM CHAIR PRIDEMORE: Happy holidays,
22 Mr. Brown.

23 All right. This is all that I have that's been
24 sent. Okay. We have went well beyond the public
25 comment time.

1 Parties, let your witnesses know that we are --
2 we will take the ten-minute break, and then we will
3 come back after the ten-minute break, and we will
4 begin the hearing. All right. With that, we are
5 adjourned until 10:54.

6 (A recess was taken.)

7 MADAM CHAIR PRIDEMORE: All right. We are back
8 on the record. Housekeeping matters? Parties have
9 housekeeping matters to go over?

10 (No response.)

11 MADAM CHAIR PRIDEMORE: Nothing? Staff?

12 MR. THOMAS: No, ma'am.

13 MADAM CHAIR PRIDEMORE: So according to my
14 math, there are ten intervenors present. If you
15 showed up and you were not here for roll call, please
16 let me know.

17 (No response.)

18 MADAM CHAIR PRIDEMORE: All right. Georgia
19 Interfaith Power & Light, your witness.

20 MS. WHITFIELD: Thank you, Madam Chairwoman.
21 Georgia Interfaith Power & and Light calls Justin
22 Barnes to the stand. Could you please stand and
23 raise your right hand.

24 Thereupon,

25 JUSTIN R. BARNES,

1 having been duly sworn, testified as follows:

2 DIRECT EXAMINATION

3 BY MS. WHITFIELD:

4 Q Please state your full name and by whom you are
5 employed.

6 A My name is Justin R. Barnes. I am the director
7 of research at EQ Research, LLC.

8 Q On whose behalf are you testifying today?

9 A I am testifying on behalf of Georgia Interfaith
10 Power & Light.

11 Q On November 18th of this year, did you prefile
12 or cause to be prefiled a public disclosure version of
13 38 pages of supplemental direct testimony in
14 question-and-answer format in Docket 44280?

15 A I did.

16 Q Did you also cause to be prefiled along with
17 your testimony attachments marked as Exhibits JRB-4 and
18 JRB-5?

19 A I did.

20 Q Mr. Barnes, do you have any corrections or
21 changes to your prefiled direct testimony or attachments at
22 this time?

23 A I have no corrections.

24 Q If I were to ask you the same questions that
25 appear in your prefiled testimony at the hearing today under

1 oath, would your answers be the same?

2 A They would.

3 MS. WHITFIELD: Madam Chair, I move to have
4 Mr. Barnes' supplemental prefiled testimony entered
5 into the record as if given orally from the stand.
6 Finally, I would ask as well that JRB-4 and JRB-5
7 attached to Mr. Barnes' prefiled supplemental
8 testimony be marked for identification as
9 GIPL Exhibits 11 and 12.

10 MADAM CHAIR PRIDEMORE: So moved, so marked.

11 (Whereupon, the prefiled testimony Justin R.
12 R. Barnes follows:)

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**BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION**

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

SUPPLEMENTAL DIRECT TESTIMONY OF JUSTIN BARNES

ON BEHALF

OF GEORGIA INTERFAITH POWER & LIGHT

November 18, 2022

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1 **I. INTRODUCTION**

2 **Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT**
3 **POSITION.**

4 A. My name is Justin R. Barnes. My business address is 1155 Kildaire Farm Road, Suite 202,
5 Cary, North Carolina, 27511. My current position is Director of Research with EQ
6 Research LLC.

7 **Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?**

8 A. I am submitting testimony on behalf of Georgia Interfaith Power & Light (“GIPL”).

9 **Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE**
10 **GEORGIA PUBLIC SERVICE COMMISSION (“THE COMMISSION”)?**

11 A. Yes. I submitted testimony earlier in this rate case proceeding and appeared at the hearing
12 on November 9, 2022. I also sponsored testimony in the 2019 Georgia Power Company
13 (“GPC” or “the Company”) Rate Case, Docket No. 42516.

14 **Q. PLEASE SUMMARIZE YOUR RELEVANT EXPERIENCE AS IT RELATES TO**
15 **THIS PROCEEDING.**

16 A. My experience is summarized in my written direct testimony filed in this docket on October
17 20, 2022 and listed in greater detail my curriculum vitae attached to that testimony as
18 Exhibit JRB-1.

19 **Q. PLEASE SUMMARIZE THE PURPOSE OF YOUR TESTIMONY AND HOW IT**
20 **IS ORGANIZED.**

21 A. My testimony addresses the Company’s supplemental testimony regarding the purported
22 “cost shift” associated with the monthly netting option under the Renewable and Non-
23 renewable Resources tariff (“Schedule RNR”) and by residential distributed generation

1 (“DG”) customers more generally, as well as related issues associated with proposed future
2 policies and rates for DG customers. My testimony is organized into the following sections:

- 3 • Section II briefly summarizes the Company’s DG proposals, provides an analysis of
4 the Company’s framing of the issue of potential cost shifting, and identifies significant
5 inaccuracies in the Company’s analysis of potential revenue erosion due to DG.
- 6 • Section III addresses the Company’s proposal to require residential customers that
7 enroll on Schedule RNR on or after January 1, 2023 to take supply service under the
8 Schedule TOU-RD residential demand rate.
- 9 • Section IV contains my proposal for an expansion of the Schedule RNR monthly
10 netting option, including my proposal for a minimum bill for residential customers
11 under the expanded program.
- 12 • Section V contains my proposal for the establishment of legacy rights for current and
13 future Schedule RNR customers, including justification for each element.
- 14 • Section VI contains my concluding remarks and summarized recommendations.

15 **Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.**

16 A. I recommend that the Commission take the following actions on the Company’s DG
17 proposals and related matters:

- 18 • Deny the Company’s request to require future residential Schedule RNR customers to
19 take service under Schedule Time of Use – Residential Demand (“Schedule TOU-
20 RD”).
- 21 • Deny the Company’s request for a monthly netting revenue erosion adjustment.
- 22 • Reinstate the Schedule RNR monthly netting option with the following guardrails in
23 place:

- Limit participation in the monthly netting program to 3% of the Company's 2021 peak load;
- Revisit and assess the program when participation approaches the 3% cap; and
- Require residential customers that enroll in the expanded monthly netting option to pay a minimum monthly bill of \$22.34/month, which is equivalent to the residential class customer-related unit cost.
- Establish legacy rights for both current and future Schedule RNR systems for a term of 20 years or longer that allow qualifying customers to: (a) remain on the DG tariff option of their choice (e.g., monthly netting); and (b) take supply service under any rate otherwise available to non-DG customers within their rate class.
- Establish that legacy rights will not be affected by either: (a) the subsequent addition of battery storage to a system; or (b) system repairs or equipment replacements that increase the generating capacity of the system by no more than the greater of 1 kW or 10% of its originally installed capacity.

II. THE COMPANY'S COST SHIFTING ARGUMENT & RELATED PROPOSALS

A. Summary of the Company's Proposals

Q. PLEASE DESCRIBE THE COMPANY'S SPECIFIC DG-RELATED PROPOSALS AND ITS JUSTIFICATION FOR THOSE PROPOSALS.

A. The Company makes two specific proposals in its supplemental testimony. First, GPC continues to oppose any expansion of the Schedule RNR monthly netting option beyond the current cap of 5,000 customers or 32 megawatts of capacity, whichever came first. Second, it proposes to require all residential customers that enroll on Schedule RNR on or

1 after January 1, 2023 to take service under Schedule TOU-RD, the residential demand rate.
2 The consequence of these proposals will be that new residential DG customers would be
3 compensated for all instantaneous exports to the grid at the Company's Solar Avoided Cost
4 Rate (2.89 cents/kWh for 2023)¹ and would no longer have their choice of supply rate from
5 otherwise available residential rate schedules.

6 The Company justifies these proposals by pointing to its purported analysis of cost
7 shifting under the Residential Service Schedule ("Schedule R") and Schedule TOU-RD
8 with both monthly netting and instantaneous export compensation regimes. This analysis
9 calculates forgone Company revenues (less fuel and other variable costs) based on what a
10 customer would pay before installing DG and what they would pay after installing DG
11 under the different DG tariff and supply rate scenarios. Essentially, the Company
12 characterizes all customer cost savings (less fuel and other variable costs) – *including*
13 customer savings resulting from the customer's consumption of on-site generated
14 electricity behind the meter – as a cost shift. The Company's proposed solution to this
15 revenue erosion is to require Schedule RNR customers to take service under a rate,
16 Schedule TOU-RD, that significantly reduces DG customers' opportunities to save money.

17 **Q. HAS THE COMPANY MODIFIED ITS PROPOSAL FOR THE \$1.4 MILLION**
18 **REVENUE EROSION ADJUSTMENT ASSOCIATED WITH THE EXISTING**
19 **MONTHLY NETTING OPTION?**

20 **A.** This element remains unchanged from what the Company proposed in its direct case. In its
21 supplemental testimony, the Company presents a slightly different analysis of potential

¹ GPC's Avoided Cost and Solar Avoided Cost Projections, Dkt. 16573 (July 29, 2022),
<https://psc.ga.gov/search/facts-document/?documentId=191003>.

1 revenue erosion associated with monthly netting and customer participation on Schedule
2 RNR more generally, but this does not appear to have changed its position on the amount
3 of the proposed revenue adjustment.

4 ***B. Company Framing of Purported Cost Shift***

5 **Q. HAS THE COMPANY’S FRAMING OF THE QUESTION OF COST-SHIFTING**
6 **CHANGED SINCE IT FILED ITS DIRECT TESTIMONY?**

7 A. No. The results of the Company’s revenue erosion estimate have changed for several
8 reasons, such as differences in how the Company modeled DG customer bill savings, the
9 inclusion of riders as opposed to just base rates, and the use of a different “value” rate for
10 exports to the grid. These differences aside, the Company continues to inappropriately
11 conflate potential revenue erosion with interclass and intraclass cost shifting. The
12 Company’s request remains based on the idea that it is entitled to a specific amount of
13 revenue towards embedded costs, deriving this amount by estimating what DG customers
14 would have paid in the absence of DG compared to what they would pay after installing
15 DG.

16 In its supplemental testimony, the Company digs deeper into this misplaced
17 reasoning by extending its argument beyond potential revenue erosion associated with
18 monthly netting to an alarming perspective that also encompasses all customer savings
19 from DG, including generation produced and consumed directly behind the customer
20 meter. Thus, GPC’s position is effectively this: Any time a customer reduces what they
21 pay the Company, they are engaged in cost shifting.

1 **Q. PLEASE EXPLAIN WHY POTENTIAL REVENUE EROSION IS NOT**
2 **EQUIVALENT TO SHIFTING COSTS TO NON-DG CUSTOMERS.**

3 A. At most, potential revenue erosion reflects only an interparty cost shift between DG solar
4 customers and the Company's shareholders. An interclass or intraclass cost shift does not
5 exist currently. Rather, an interclass or intraclass cost shift will exist only if the Company
6 is permitted to establish its proposed revenue adjustment. Absent that adjustment, all other
7 GPC customers are unaffected by, and indifferent to, the current population of DG solar
8 customers, or future DG customers, as long as the Company's earnings remain within the
9 earnings band.

10 **Q. DURING THE NOVEMBER 8–10 HEARING, THERE WAS SOME DISCUSSION**
11 **OF SCENARIOS UNDER WHICH THE COMPANY COULD EXPERIENCE**
12 **REVENUE EROSION, AND HOW THAT POTENTIAL SHOULD BE**
13 **ADDRESSED. COULD YOU EXPLAIN AND RESPOND TO THE COMPANY'S**
14 **POSITION AS YOU UNDERSTAND IT?**

15 A. Yes. I understand the Company's position to be that it is appropriate to adjust its revenues
16 outside of its cost of service study, and outside of the earnings band and revenue sharing
17 mechanism, for variations that are not captured in the forecasted billing determinants which
18 form the basis for calculating the rates necessary to meet the revenue requirement. During
19 cross examination in the November hearing, Company counsel questioned me about
20 examples involving the potential for lower revenues due to customers using less electricity
21 through the installation of DG or other means or by switching to a rate that is less costly
22 for them. The Company's position appears to be that those possibilities constitute a

1 potential cost similar to “known and measurable changes,” and merit possible adjustments
2 to things like rate base or O&M costs outside of the reference test year.

3 I disagree. Revenue variations that arise from variations in load relative to forecasts
4 are distinctly different from cost-related changes because total load variations are
5 inherently not measurable. Variations in load and the accompanying variations in revenue
6 arise due to many factors (e.g., weather, customer accretion or attrition) that are both
7 unpredictable and beyond the control of either customers or the Company. In other words,
8 while certain factors which influence load estimates upon which rates are based can be
9 known, the aggregate impact cannot be reliably measured. The aggregate impact is
10 critically important because it is what defines realized revenue. For example, during a rate
11 year or over the course of a rate planning period, the Company might experience a gross
12 loss in revenue due to customers installing DG or switching to less costly rates, but during
13 the same reference period, it may experience a greater gain in revenue due factors like
14 weather or appliance electrification that contribute to increased customer usage. The end
15 result is a net revenue increase and higher return on equity (“ROE”) due to factors
16 independent of those within the Company’s control.

17 This hypothetical scenario constitutes realized revenue accretion rather than
18 revenue erosion, and there would be no basis for a revenue adjustment that further increases
19 the net revenue gain. That is, revenue erosion or accretion should be evaluated from an
20 aggregate standpoint that implicitly grants equal weight to the multiple contributing factors
21 that may ultimately net positively or negatively. This is precisely the purpose of the
22 earnings band and sharing mechanism, which seeks to balance the interests of shareholders
23 and ratepayers from an aggregate revenue and cost standpoint. A practice of separating out

specific line items contravenes this objective and introduces bias towards shareholders into that balance under the circumstances in which the Company typically operates.

Q. PLEASE ELABORATE ON HOW THE COMPANY’S PROPOSAL INTRODUCES “BIAS” INTO THE EARNINGS BAND AND SHARING MECHANISM.

A. Consider the following hypothetical example: Assume that (a) DG customers collectively avoid paying \$1 million in charges that they would have otherwise paid if they had not installed DG, and (b) the Company’s earned return is above the authorized return but below the ceiling under which the sharing of excess revenue would be required, as testimony has previously shown is quite typical.²

In this scenario, the Company’s proposed revenue adjustment would be spread across forecasted billing determinants, effectively creating an incremental charge. For instance, in this hypothetical example, if forecasted sales are 10 billion kWh, the incremental charge is derived by dividing \$1 million by 10 billion kWh, resulting in an incremental charge of \$0.0001/kWh (0.01 cents/kWh).

In this reasonable scenario, the Company’s proposed revenue adjustment results in further overearning as the Company is not obligated to return any money to customers. This is what I am referring to as “bias” that benefits shareholders at the expense of customers. Furthermore, the incremental amount of overearning may even be higher than the nominal \$1 million revenue adjustment because the overearning may itself be caused by actual sales being higher than forecasted sales. That is, the incremental rate could recover more than \$1 million because it is assessed on actual sales amounts which are

² Direct Testimony of Kevin Lucas & Thatcher Young, Table 4 at p. 43. As shown in Table 4, most earnings above the authorized ROE are within the deadband.

1 higher than what was necessary to raise \$1 million in incremental revenue. Using the above
2 example, if actual sales were 10.1 billion kWh (1% over forecasted sales), the incremental
3 rate would recover \$1.01 million (i.e., the product of 10.1 billion kWh and 0.01
4 cents/kWh), an additional \$10,000.

5 **Q. DOES THE COMPANY ACKNOWLEDGE THAT ITS EVALUATION**
6 **FRAMEWORK IS BASED ON RETENTION OF UTILITY REVENUE?**

7 A. It does. In response to a data request about the interaction between the earnings band and
8 revenue sharing mechanism and DG-related revenue erosion, the Company stated:³

9 Any revenue erosion not captured through retail rates,
10 which occurs during the 3-year alternate rate plan will
11 serve to lower the Company's earned ROE. As a matter
12 of appropriate ratemaking principles, to set retail rates at
13 the correct level to recover the Company's retail cost of
14 service from customers, any amount of revenues lost
15 from, or avoided by, a certain group of customers must
16 be recovered from the remaining body of customers.

17 I agree that retail rates should be designed to recover the Company's costs to serve
18 customers and provide it with a reasonable opportunity to earn an appropriate return. But
19 the Company neglects to mention that recent history indicates that it always overearns
20 relative to its authorized ROE. Regardless of the reasons this has occurred, the existence
21 of these overearnings is undeniable fact. Moreover, if one views the "correct level" of rates
22 necessary to recover the Company's costs of providing service to be the amounts that
23 produce an earned ROE in line with its authorized ROE, the Company's proposal for
24 additional cost recovery is in conflict with this objective since it would result in rates that
25 produce more revenue even as the Company is already consistently overearning. It appears

³ Response to STF-TAI-8-14.

1 that the Company wants to have its cake and eat it too. The sense of entitlement is truly
2 astounding.

3 ***C. Inaccuracies in the Company's Revenue Erosion & Cost Shifting Analysis***

4 **Q. HAVE YOU IDENTIFIED ERRORS IN THE COMPANY'S COST SHIFT**
5 **ANALYSIS? IF SO, PLEASE EXPLAIN.**

6 A. Yes, I have identified numerous and egregious errors in the Company's cost shift analysis.
7 As I have already discussed, the Company's analysis suffers from a foundational flaw in
8 that it conflates the potential for revenue erosion with cost shifting. Setting that framing
9 issue aside, the Company's modeling of potential revenue erosion associated with
10 residential DG is rife with errors that grossly overstate the magnitude of the "problem,"
11 even if the Commission were to accept the Company's framing.⁴

12 The specific inaccuracies that I have identified stem from two sources: (a) a major
13 formula error in the Company's modeling of pre-solar bills under Schedule R, which
14 incorrectly inflates the revenue erosion estimate by 63%, and (b) assumptions used in the
15 Company's solar production modeling. Both cause the Company to overstate potential
16 customer savings, and in turn overstate its revenue erosion estimates.

⁴ My discussion of errors does not address other potential sources of inaccuracy in the Company's modeling, such as the use of a residential only sample, a failure to account for daylight savings time in its solar production and load matching process, and the use of load profiles based on single customers rather than a statistically robust model. These flaws undoubtedly compromise the accuracy of the Company's projections, but I have not conducted the analysis necessary to quantify them.

1 **Q. PLEASE DESCRIBE THE FORMULA ERROR THAT YOU IDENTIFIED IN THE**
2 **COMPANY'S CALCULATION OF PRE-SOLAR BILLS UNDER SCHEDULE R.**

3 A. The Company appears to have inadvertently multiplied the charge for the third tier of
4 summer energy usage (greater than 1,000 kWh) by two in its pre-solar bill estimate.
5 Specifically, the formula contains a syntax mistake that causes the result to be multiplied
6 by two rather than rounded to two decimal points. The erroneous portion of the equation is
7 highlighted in the furthest right portion of the text. I have also attached my workpaper
8 containing a corrected version of the Company's revised response to STF-TAI-7-1,
9 Attachment B, labeled as Exhibit JRB-4.

10 Incorrect Company Formula:

11 =ROUND((IF(C10<1001,0,(C10-1000)*\$R\$10))*2,)

12 Corrected Formula:

13 =ROUND((IF(C10<1001,0,(C10-1000)*\$R\$10)),2)

14 That error dramatically inflates the Company's DG savings projections, in
15 particular for the high usage customer quartiles used in its analysis. Correcting it reduces
16 the Company's calculated revenue erosion for Schedule R with instantaneous netting from
17 \$1,093/customer per year to \$560/customer per year (a reduction of \$533/customer per
18 year).⁵ The total alleged cost shift is also reduced by \$533/customer per year, from
19 \$1,356/customer per year to \$823/customer per year. These revised amounts are exclusive
20 to this correction. They do not reflect the correction of other problems with the Company's
21 calculations that I describe below.

⁵ Compare Figure 3 in Company Witness Legg/Evans supplemental direct testimony & Exhibit LTL-1 with Exhibit JRB-4. My workpaper shows the results of the original analysis provided by the Company and the corrected results in the CORRECTED Summary tab and the ORIGINAL Matrix and CORRECTED Matrix tabs.

1 **Q. PLEASE DESCRIBE THE PROBLEMS YOU IDENTIFIED IN THE COMPANY’S**
2 **SOLAR PRODUCTION MODELING.**

3 A. I have identified the following issues with the Company’s PVWatts modeling
4 assumptions:⁶

- 5 • The Company’s estimates of solar production for a reference system are based on a due
6 south system orientation. In reality, few residential systems are installed with full direct
7 south-facing orientation because they are limited by the orientation of the plane or
8 planes of the rooftop on which they are installed. An average Southwest or Southeast
9 orientation in PVWatts reduces annual production per kilowatt (“kW”) by roughly 4%,
10 while a primarily East or West orientation reduces annual production per kW by
11 approximately 13–14%.
- 12 • The Company’s estimates of solar production for a reference system are based on first-
13 year production values. Due to normal degradation of panels over time, this overstates
14 average annual system production by 5% over the course of a hypothetical 20-year
15 system lifetime assuming typical production degradation of 0.5% annually.
- 16 • The Company also erred by modeling solar systems as “fixed tilt – open rack” systems
17 rather than “roof mount” systems in PVWatts, as would be typical for residential
18 systems, which overstates expected production by a small amount.
- 19 • The Company entered inflated system sizes into PVWatts with one decimal place, in
20 each case rounding up to the nearest tenth of a kW compared to the average system size

⁶ Based on Company response to STF-TAI-8-6, Attachment.

1 that it calculated elsewhere in its analysis.⁷ This produces an overstatement of
2 production up to 50 kWh annually.

3 **Q. WHAT IS THE COLLECTIVE EFFECT OF THE ERRORS THAT YOU**
4 **IDENTIFIED IN THE COMPANY’S SOLAR MODELING?**

5 A. The average annual production from the Company’s modeling is 1,421 kWh per kW-DC.
6 Using a Southwest system orientation (i.e., primarily but not due South) and correcting the
7 system type and system size inputs, the estimated annual production is reduced to 1,366
8 kWh per kW-DC (a 4% reduction). A due West orientation would reduce estimated
9 production further to 1,240 kWh per kW-DC (a 14.6% reduction). After applying a 5%
10 system degradation adjustment to reflect average annual production over the life of a
11 system, the average annual production estimates for the Southwest- and West-facing
12 systems, respectively, are 1,298 kWh per kW-DC (9.5% reduction) and 1,178 kWh per
13 kW-DC (20.7% reduction).

14 Because system production feeds directly into the Company’s calculation of lost
15 revenues, these modeling inaccuracies overstate the Company’s revenue erosion estimates
16 by roughly 10% to 20%. These amounts would be increased by any further losses due to
17 factors like shading that are higher than the PVWatts default assumptions (e.g., 3% for
18 shading).⁸

⁷ Based on Company response to STF-TAI-8-6, Attachment and the Company’s supplemental response to STF-TAI-7-1 (Revised), Attachment A.

⁸ See PVWatts System Documentation, available by clicking the “information” button in the System Info portal.
<https://pvwatts.nrel.gov/pvwatts.php>

1 **Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE COMPANY'S**
2 **MODELING OF POTENTIAL REVENUE EROSION FROM RESIDENTIAL DG**
3 **INSTALLATIONS?**

4 A. I reject the dubious premise that customer bill savings against embedded costs are
5 equivalent to harmful cost shifting. Such a conclusion can only be reached with a far more
6 extensive analysis that comprehensively identifies the short-term impacts on allocation of
7 those embedded costs, and the long-term avoided costs (i.e., marginal costs) for all aspects
8 of the system. Under the present circumstances, it is clear that there is no cost shift
9 whatsoever because absent the Company's proposed revenue adjustment, non-DG
10 customers would not be allocated any additional costs or otherwise pay higher rates due to
11 the installation of DG by a subset of customers.

12 That issue aside, I have demonstrated that the Company's estimates of the amount
13 of DG-related revenue erosion cannot be relied upon. To the extent that the Commission
14 gives any weight to the Company's framing of the matter as it considers DG policies and
15 rates, it should be aware that the Company's estimates simply cannot be trusted.

16 **III. MANDATORY SERVICE UNDER SCHEDULE TOU-RD**

17 **Q. PLEASE DESCRIBE IN GENERAL HOW DEMAND RATES TEND TO IMPACT**
18 **DG CUSTOMERS.**

19 A. There are two effects. First, demand rates invariably reduce how much money a customer
20 can save by installing DG because solar typically provides little to no reduction in a
21 customer's non-coincident demand during any given month, and the inclusion of a demand
22 rate component lowers the rates for any volumetric components.

1 Second, demand rates in general are advantageous for higher load factor customers,
2 which in the residential context are typically customers with well above average energy
3 consumption. Customers with below average or average usage tend to be disadvantaged by
4 demand rate structures. The former group can be thought of as “structural savers,” whereas
5 the latter group are “structural non-savers.” In other words, holding all other factors
6 constant, any given rate structure has winners and losers relative to another, and demand
7 rates tend to create winners out of high usage customers. It follows then that demand rates
8 tend to disadvantage DG customers because DG lowers the total amount of electricity that
9 a customer consumes from the grid.

10 **Q. IS THERE ANY SPECIFIC EVIDENCE IN THE RECORD OF THIS CASE**
11 **WHICH RELATES TO THE IMPACTS OF SCHEDULE TOU-RD ON**
12 **RELATIVELY LOWER USAGE CUSTOMERS?**

13 A. Yes. As I and other intervenor and Staff witnesses demonstrated in direct case testimony
14 filed on October 20, 2022, Schedule TOU-RD resulted in significantly higher rates and
15 significantly higher overall bills relative to other available rates since the beginning of
16 2021.⁹ This coincided with the establishment of Schedule TOU-RD as the default rate for
17 new residential premises, a dramatic increase in Schedule TOU-RD enrollment, and a
18 corresponding significant decline in average usage by Schedule TOU-RD customers.
19 Accordingly, Schedule TOU-RD was generally harmful to those new customers, who
20 happened to also be customers with relatively lower energy usage. I also demonstrated that

⁹ See e.g., Barber et al. Direct Testimony at 81 (Oct. 20, 2022); Deffley & Nifong Direct Testimony at 16 (Oct. 20, 2022); Lucas & Young Direct Test. at 58-62 (Oct. 20, 2022).

1 these same customers who paid more on average on Schedule TOU-RD were less costly to
2 serve according to the metrics used in the Company's cost of service study.¹⁰

3 **Q. HOW WOULD MAKING SCHEDULE TOU-RD MANDATORY FOR NEW**
4 **RESIDENTIAL DG CUSTOMERS AFFECT THOSE CUSTOMERS?**

5 A. It would reduce customer savings due to DG for all new DG customers, and further reduce
6 total net savings for customers that are already structural non-savers by increasing their
7 pre-solar bill relative to what it would have been under another rate. The combined effects
8 would be greatest on customers with relatively lower pre-solar usage since they are most
9 adversely affected by the demand rate structure itself.

10 **Q. HAVE YOU ESTIMATED HOW MUCH SCHEDULE TOU-RD WOULD REDUCE**
11 **CUSTOMER SAVINGS ATTRIBUTABLE TO DG?**

12 A. Yes. Table 1 below is based on the Company's revenue erosion analysis.¹¹ It shows the
13 DG savings rates for each of the four groups of customers under each of the four DG tariff
14 and rate structure regimes. For reference, the groups are ordered in progression from
15 customers with the lowest pre-solar usage (Group 1) to highest (Group 4). The DG savings
16 rate is calculated as the total cost savings attributable to on-site solar divided by solar
17 system production. It does not incorporate the effect that Schedule TOU-RD has on a
18 customer's bill due to structural savings or non-savings, only the savings due to solar from
19 the customer's reference bill under Schedule TOU-RD.

¹⁰ Barnes Direct Testimony at 48-49.

¹¹ Table 1 was generated using STF-TAI-7-1 (Revised), Attachment B after incorporating the formula correction that I previously described. It does not reflect any further changes related to my other criticisms of the Company's model.

Table 1: Solar Savings Reductions Under Schedule TOU-RD vs. Schedule R

Rate & DG Tariff Structure		Group 1	Group 2	Group 3	Group 4
		DG Savings Rate (\$/kWh)	DG Savings Rate (\$/kWh)	DG Savings Rate (\$/kWh)	DG Savings Rate (\$/kWh)
Schedule R	Monthly Netting	\$0.0996	\$0.1129	\$0.1113	\$0.1118
Schedule R	Instantaneous	\$0.0616	\$0.0798	\$0.0883	\$0.0907
Schedule TOU-RD	Monthly Netting	\$0.0449	\$0.0639	\$0.0609	\$0.0537
Schedule TOU-RD	Instantaneous	\$0.0373	\$0.0590	\$0.0567	\$0.0500
Schedule TOU-RD Difference From Schedule R					
Monthly Netting		(\$0.0547)	(\$0.0489)	(\$0.0504)	(\$0.0580)
Instantaneous		(\$0.0243)	(\$0.0207)	(\$0.0316)	(\$0.0406)

The average difference in the total value generated by solar for a customer if that customer is forced to take Schedule TOU-RD service is a reduction of 47% under a monthly netting scenario and 32% under an instantaneous netting scenario. Relative to monthly netting under Schedule R, instantaneous netting under Schedule TOU-RD produces an average savings reduction of 52%, and Group 1 is the most severely affected with a savings rate reduction of 63%.

Q. HOW WOULD DIFFERENT TYPES OF DG CUSTOMERS BE AFFECTED BY THE COLLECTIVE IMPACTS OF STRUCTURAL SAVINGS OR NON-SAVINGS AND THE REDUCTION IN THE SOLAR SAVINGS RATE?

A. They differ considerably depending on the customer's usage profile. As one would expect, customers with lower relative initial usage (e.g., Group 1) would experience significant adverse impacts, whereas customers with higher relative usage (e.g., Group 4) are actually better off under Schedule TOU-RD regardless of the DG tariff regime because they are significant structural savers. Table 2 shows net DG savings under the Company's proposal

considering both the impacts of lower DG savings rates and the impacts of rate switching relative to Schedule R (i.e., structural non-savings or savings).¹²

Table 2: Net Solar Savings Reductions Under Schedule TOU-RD vs. Schedule R

Rate & DG Tariff Structure		Group 1	Group 2	Group 3	Group 4
		DG Savings Rate (\$/kWh)	DG Savings Rate (\$/kWh)	DG Savings Rate (\$/kWh)	DG Savings Rate (\$/kWh)
Schedule R	Monthly Netting	\$0.0996	\$0.1129	\$0.1113	\$0.1118
Schedule R	Instantaneous	\$0.0616	\$0.0798	\$0.0883	\$0.0907
Schedule TOU-RD	Monthly Netting	\$0.0146	\$0.0345	\$0.0711	\$0.1284
Schedule TOU-RD	Instantaneous	\$0.0071	\$0.0296	\$0.0670	\$0.1247
Schedule TOU-RD Difference From Schedule R					
Monthly Netting		(\$0.0850)	(\$0.0783)	(\$0.0401)	\$0.0167
Instantaneous		(\$0.0546)	(\$0.0501)	(\$0.0213)	\$0.0340

The primary takeaway from Table 2 is that the lower usage customers that comprise Group 1 experience near zero net DG savings under the Company’s proposal because Schedule TOU-RD is significantly more expensive for them than Schedule R. Group 2 customers with “medium” relative usage are also adversely impacted, but not to the same degree as the lower usage customers in Group 1. On the other hand, high usage Group 4 customers actually benefit from being placed on Schedule TOU-RD as indicated by the fact that their net savings rates under Schedule TOU-RD are actually higher than their savings with DG under Schedule R. This occurs because they are structural savers to a degree that overshadows the lower DG savings that all customers experience under Schedule TOU-RD relative to Schedule R.

¹² Table 2 was generated using STF-TAI-7-1 (Revised), Attachment B after incorporating the formula correction that I previously described. It does not reflect any further changes related to my other criticisms of the Company’s model.

1 It is particularly notable that the net savings rate for Group 1 customers approach
2 zero, with the savings rate ranging from 0.7 - 1.5 cents/kWh. Relative to monthly netting
3 under Schedule R, this amounts to a decrease from 89% - 93% in the net savings rate. It is
4 plausible that some low usage customers would actually pay more under Schedule TOU-
5 RD after installing solar than they would under Schedule R without solar. Group 2
6 customers are little better off, as their total net savings rates are less than 4 cents/kWh, a
7 reduction of 74% relative to monthly netting under Schedule R.

8 **Q. ARE THESE DIFFERENCES IN NET DG SAVINGS RATES CONSISTENT WITH**
9 **COST CAUSATION?**

10 A. No. As I previously testified, Schedule TOU-RD is punitive to customers with infrequent
11 high demands, including those that do not occur during time periods that are likely to
12 coincide with system peaks. Table 3 illustrates the timing portion of this misalignment by
13 comparing the load profile that the Company used for Group 1 customers, who are
14 penalized the most by Schedule TOU-RD, with Group 4 customers, who benefit the most.¹³

¹³ Developed from STF-TAI-7-1 (Revised), Attachment B.

Table 3: Comparison of Monthly Peak Timing

Month	Group 1	Group 4
1	OFF	OFF
2	OFF	OFF
3	SUPER	OFF
4	OFF	OFF
5	OFF	OFF
6	OFF	OFF
7	OFF	ON
8	OFF	ON
9	SUPER	ON
10	OFF	OFF
11	OFF	OFF
12	SUPER	OFF

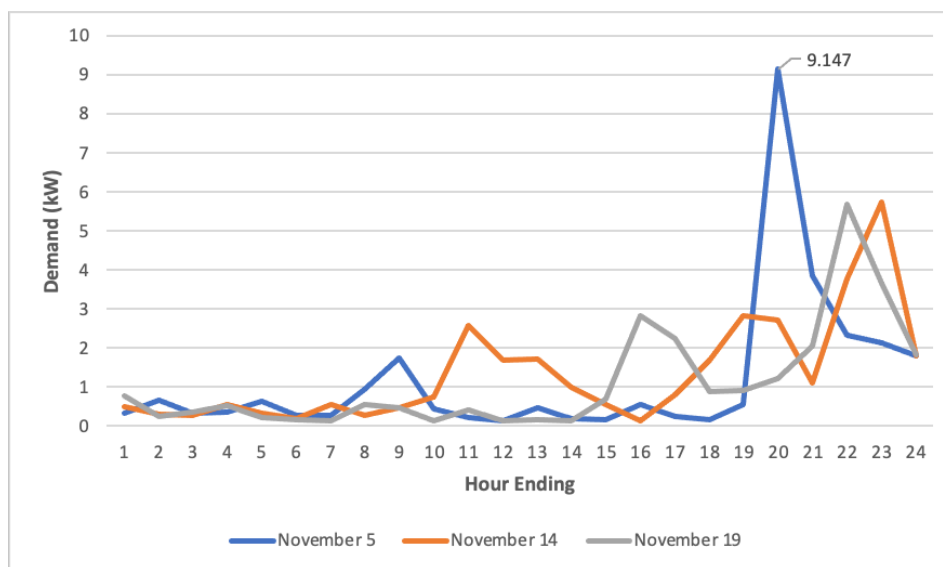
As shown in Table 3, Group 1 shows monthly peaks exclusively during off-peak and super off-peak periods whereas Group 4 peaks are set during the on-peak period in three of the four summer months and none occur during super off-peak periods.

The punitive impacts of Schedule TOU-RD in terms of the frequency of high demands is illustrated in Figure 1, which shows the 24-hour profile for the days in November during which the three highest monthly demand registrations occurred in the Group 1 load profile.¹⁴ The Group 1 demand charge is determined by a single, abnormally high demand registration on November 5. There is no particular reason to believe that the hour ending at 8 PM on November 5 coincided with a period of high system demand that would cause the additional grid costs, yet that single instance determines the customer's demand charge for the month. Such a result is inconsistent with cost causation.

¹⁴ Developed from STF-TAI-7-1 (Revised), Attachment B.

1

Figure 1: Group 1 November Highest Demand Days



2 **Q. ARE THERE ANY OTHER WAYS IN WHICH SCHEDULE TOU-RD IS POORLY**
 3 **SUITED AS A SOLUTION TO POTENTIAL REVENUE EROSION FROM DG?**

4 A. Yes. The Company’s revenue erosion analysis, for all its faults, shows that despite the fact
 5 that Schedule TOU-RD is most penalizing to low usage Group 1 customers and the most
 6 beneficial to high usage Group 4 customers, Group 1 actually causes the least amount of
 7 revenue erosion while Group 4 causes the most. Table 4 shows the revenue erosion
 8 calculated by the Company’s model for Schedule R on a dollars per kW of installed solar
 9 basis.¹⁵

10 **Table 4: Alleged Revenue Erosion per kW of Solar by Group (Instantaneous)**

Quartile	Schedule R Revenue Erosion (\$ per kW of installed solar)
Group 1	\$60
Group 2	\$93
Group 3	\$106
Group 4	\$108

¹⁵ Developed from STF-TAI-7-1 (Revised), Attachment B, after previously noted corrections.

1 The differences in the values in Table 4 between groups are caused by the tiered
2 summer rate structure, which results in high usage customers offsetting usage at higher
3 rates, which directly translates to the amount of customer savings. Table 4 demonstrates
4 how misaligned the Company's proposal to use Schedule TOU-RD as a revenue erosion
5 "fix" is with the actual character of the alleged problem. The groups that are least
6 responsible for revenue erosion (lower usage customers) are the most adversely impacted
7 by the Company's proposal, whereas the groups most responsible (higher usage customers)
8 are less affected, and are likely to actually benefit from Schedule TOU-RD service due to
9 structural savings. In fact, according to the Company's own analysis, Group 4 customers
10 save almost as much money by switching from Schedule R to Schedule TOU-RD than they
11 do by installing DG. The Company conveniently omits to mention this type of revenue
12 erosion, which from the viewpoint it adopts for DG-related revenue erosion, amounts to a
13 cost shift.

14 **Q. WHAT SHOULD THE COMMISSION TAKE AWAY FROM YOUR ANALYSIS**
15 **ON THE DIFFERING IMPACTS THAT SCHEDULE TOU-RD HAS ON**
16 **DIFFERENT TYPES OF CUSTOMERS?**

17 A. The key takeaways are the following. Schedule TOU-RD:

- 18 (1) is equally misaligned with cost causation for DG customers as it is for
19 residential customers as a whole,
20 (2) would cause net DG savings rates for lower usage customers to approach zero,
21 and potentially be negative for some customers, and

1 (3) is thoroughly unsuitable as a solution to the supposed revenue erosion problem
2 because its impacts on different groups are directly opposite to nature of supposed
3 problem.

4 The Commission could additionally infer that the relatively lower usage customers
5 that are most adversely affected by Schedule TOU-RD reside in smaller homes and are less
6 affluent than the customers in higher usage groups, who have average electricity use that
7 is well above the residential class average. The Company's proposal makes DG installation
8 totally impractical for its less affluent customers.

9 **Q. ARE THERE ANY OTHER INVESTOR-OWNED UTILITIES ("IOUS") IN THE**
10 **COUNTRY THAT REQUIRE RESIDENTIAL DG CUSTOMERS TO TAKE**
11 **ELECTRIC SERVICE UNDER A DEMAND RATE?**

12 A. I am only aware of one utility that has been permitted to do so (Black Hills Power in
13 Wyoming), despite numerous utility proposals of this type over the last several years. Two
14 other IOUs, Arizona Public Service ("APS") and Alabama Power Company ("AL Power"),
15 have used demand rate service as a customer option that allows customers to avoid paying
16 an additional fee based on system nameplate capacity, but there are nuances to both of
17 these examples. In the case of APS, a modest solar capacity fee (\$0.93/kW) was authorized
18 several years ago but has since been rescinded, allowing residential solar customers to take
19 service under an energy-only time of use rate without any additional charge. AL Power's
20 solar capacity fee is still in place, but a customer may avoid paying that fee by taking
21 service under the Residential Time Advantage ("RTA") rate accompanied by paying a
22 higher energy rate during summer peak hours or by participating in AL Power's Residential

1 Service Demand (“FD-D”) rate.¹⁶ The AL Power RTA rate has separate energy-only and
2 demand rate options, so it is not clear that a customer must take demand rate service in
3 order to avoid the solar capacity fee.¹⁷ Even so, AL Power’s solar rates should not be
4 viewed as a strong example; only a couple of hundred Alabamians have onsite solar.
5 Moving toward policies like those adopted by Alabama Power would be a step back, not
6 forward. Thus the only definitive example is Black Hills Power in Wyoming.

7 **Q. BASED ON THE NATIONAL ENVIRONMENT WHAT CAN THE COMMISSION**
8 **CONCLUDE ABOUT THE GENERAL LEVEL OF ACCEPTABILITY OF THE**
9 **COMPANY’S MANDATORY TOU-RD SERVICE PROPOSAL?**

10 A. The Commission can conclude that it would be well outside of the norm and contrary to
11 the repeated instances in which regulators in other states have declined to approve such
12 proposals. Approving it would make Georgia a very rare outlier.

13 **IV. PROPOSAL FOR SCHEDULE RNR MONTHLY NETTING EXPANSION**

14 **Q. HOW DO YOU RECOMMEND THE COMMISSION ACT ON THE SCHEDULE**
15 **RNR MONTHLY NETTING OPTION?**

16 A. I recommend that the Commission expand the availability of the Schedule RNR monthly
17 netting option with two conditions:

- 18 • Residential customers under the expanded program should be subject to a minimum
19 bill of \$22.34/month, equivalent to \$0.7344/day.
- 20 • The expanded option is available until enrollment in the monthly netting option reaches
21 3% of the Company’s 2021 peak demand.

¹⁶ <https://www.alabamapower.com/content/dam/alabama-power/pdfs-docs/Rates/RGB.pdf>

¹⁷ <https://www.alabamapower.com/residential/residential-pricing-and-rate-plans/time-advantage-rates.html>

1 **Q. HOW SHOULD THE COMMISSION ADDRESS DG TARIFF OPTIONS BEYOND**
2 **THE 3% OF PEAK DEMAND CAP THAT YOU PROPOSE?**

3 A. The Commission should undertake a more extensive evaluation of DG tariffs in the
4 Company's next rate case, or at its election, prior to that time (e.g., if enrollment approaches
5 the cap again). In order to support that evaluation, the Commission should direct the
6 Company to immediately begin collecting the data necessary to conduct a robust cost of
7 service analysis of DG customers, including but not limited to the interval data needed to
8 properly characterize DG customer load profiles.

9 ***A. Residential Monthly Minimum Bill***

10 **Q. PLEASE DESCRIBE THE BASIS FOR THE \$22.34/MONTH RESIDENTIAL**
11 **MINIMUM BILL THAT YOU RECOMMEND.**

12 A. This amount is based on my calculation of residential class customer-related costs based
13 on the Company's historic test year cost of service study. As I discussed in my testimony
14 filed October 20, 2022, I calculated this amount without modifying any aspects of the
15 methodology that the Company used in its study (including those which I challenged), so
16 it includes a portion of the costs associated with the shared distribution system (i.e.,
17 infrastructure beyond the customer's service drop) as identified by the Company's zero-
18 intercept study.

19 **Q. WHY WOULD THIS AMOUNT BE APPROPRIATE FOR ESTABLISHING A**
20 **MINIMUM BILL FOR RESIDENTIAL CUSTOMERS UNDER THE EXPANDED**
21 **MONTHLY NETTING OPTION THAT YOU RECOMMEND?**

22 A. The minimum bill is intended to ensure that DG customers fairly contribute to the recovery
23 of costs that do not vary in relation to their energy use or demand. Although I do not support

1 the use of the zero-intercept method in general as a proper basis for establishing the
2 residential basic service charge (“BSC”), it would not be unreasonable to use it to establish
3 a minimum bill for residential DG customers since it treats a significant portion of the costs
4 of the shared distribution system as unavoidable by distributed generation.

5 **Q. ARE THERE OTHER STATE PRECEDENTS FOR USING A MINIMUM BILL**
6 **DESIGN IN THIS FASHION?**

7 A Yes. Monthly minimum bills specific to DG customers have also been adopted in the Solar
8 Choice net metering successor tariffs now in place in the South Carolina service territories
9 of Duke Energy Carolinas and Duke Energy Progress,¹⁸ and for new net metering
10 customers in El Paso Electric’s Texas service territory.¹⁹ California and Hawaii have
11 established monthly minimum bills higher than the standard fixed monthly BSC for all
12 residential customers, as has Duke Energy Florida.

13 **Q. ARE YOU RECOMMENDING THAT THE COMMISSION ESTABLISH A**
14 **MINIMUM BILL FOR NON-RESIDENTIAL CUSTOMERS THAT ENROLL IN**
15 **THE EXPANDED MONTHLY NETTING TARIFF?**

16 A. No, for several reasons. First, most monthly netting participants are likely to be residential
17 customers. Second, the Company’s cost of service study only breaks out the customer-
18 related component for the residential class, so it is not possible calculate equivalent
19 minimum bill amounts, and how they compare to the respective fixed BSC, for other
20 customer classes. Third, many non-residential customers pay demand charges anyway,

¹⁸ A similar proposal is now pending before the North Carolina Utilities Commission.

¹⁹ The “new” designation refers to customers that installed a DG system after December 17, 2017.

1 which in most cases would cause their bills to exceed any reasonable minimum bill amount
2 that is based on customer-related costs.

3 ***B. Aggregate Cap of 3% of Peak Load***

4 **Q HOW DID YOU COME TO 3% OF PEAK DEMAND AS YOUR PROPOSED**
5 **AGGREGATE CAP FOR THE EXPANDED MONTHLY NETTING PROGRAM?**

6 A. My recommendation is based on consideration of several factors, as follows:

- 7 • Allowing sufficient headroom to create a reasonable likelihood that the program will
8 not be filled significantly in advance of the Company's next rate case.
- 9 • Limiting risk to the Company and its customers and allowing the Commission to
10 monitor all potential impacts from the program in the future.
- 11 • Typical caps in other states throughout the country and in the Southeast.

12 **Q. WHAT IS A "TYPICAL" AGGREGATE CAP IMPOSED ON NET METERING**
13 **PROGRAMS?**

14 A. At least 25 states have historically made net metering²⁰ available without any aggregate
15 cap at all. Where caps have been imposed, they have typically been set at a minimum of
16 1% of a utility's peak demand, with some states setting them considerably higher in the
17 range of 5% - 10%. Below is a listing of the aggregate caps present in the Southeast in
18 states where net metering is currently authorized.

- 19 • Arkansas: Uncapped
- 20 • Florida: Uncapped

²⁰ Often "net metering" refers to annual retail rate net metering; however in this discussion, the term "net metering" includes any policy with at least a monthly netting period – meaning, it may include both monthly and annual net metering policies. This is consistent with the commonly accepted definition of the term "net metering" as a mechanism that, at a minimum, allows netting of energy at the retail rate within a monthly billing period.

- 1 • Kentucky: 1%
- 2 • North Carolina: Uncapped
- 3 • South Carolina: 2% (traditional net metering); uncapped (Solar Choice monthly net
- 4 metering)
- 5 • Virginia: 6% (1% reserved for low-income customers)
- 6 • West Virginia: 3%

7 A 3% cap in Georgia would in no way be out of the ordinary, especially considering
8 that several of the previously listed states do not impose a cap on net metering at all. In this
9 regard, 3% could be considered conservative, and I believe that a higher cap could be
10 reasonable.

11 **Q. HOW WOULD POTENTIAL REVENUE EROSION AS THE RESULT OF AN**
12 **EXPANDED MONTHLY NETTING PROGRAM WITH A 3% CAP COMPARE**
13 **TO THE COMPANY’S HISTORIC OVEREARNINGS?**

14 A. As I previously discussed, the Company has overstated potential revenue losses in its
15 analysis, but even if one accepts its projections in total, the potential loss attributable to
16 monthly netting at full enrollment confined exclusively to residential customers would
17 amount to only roughly \$19.7 million/year.²¹ By comparison, GASEIA/SEIA/Vote Solar
18 Witness Lucas calculated the Company’s average excess earnings within the ROE band at
19 \$135 million/year from 2011 – 2021. The average for 2020 and 2021 was roughly \$230
20 million/year.²² In an environment of consistent overearning of this magnitude, this modest

²¹ Company revised response to STF-TAI-7-1, tab labeled Matrix specifying a monthly netting cost shift of \$1.418 million annually based on a capacity total of roughly 35 MW. Peak load was assumed to be 16,213 MW based on 2021 U.S. EIA Form 861, translating to a cap of approximately 486 MW.

²² Direct Testimony of Kevin Lucas and Thatcher Young, Table 4 at p. 43.

1 amount of revenue attrition would in no way compromise the Company's financial
2 integrity or otherwise induce a hardship.

3 **Q. HOW DO YOU RESPOND TO COMPANY WITNESS DR. GATTIE'S**
4 **CONTENTION THAT NET METERING IS NO LONGER A "PREFERRED**
5 **POLICY OPTION"?**

6 A. While it is true that some states have transitioned away from annual retail rate net metering,
7 Company Witness Dr. Gattie's assertion is inconsistent with the fact that some form of net
8 metering remains an option throughout the country in most states. By my count, there are
9 38 states plus the District of Columbia in which some form of net metering – monthly or
10 annual – is currently available. Moreover, a number of the states that have moved to non-
11 net metering-based successor regimes, such as Arizona and Hawaii, are in no way
12 comparable to Georgia in terms of the relative penetration of rooftop solar, and the
13 "successor" regimes in states that include California, New York, New Hampshire, Nevada,
14 South Carolina, and Vermont are in fact variations on net metering.

15 Georgia can use monthly net metering exactly as these other states have done to
16 provide the Company's customers with reasonable opportunities to benefit from on-site
17 solar generation and allow the market for these services to grow and mature. And to be
18 clear, unless the Commission grants the Company's requested revenue erosion rate
19 adjustment, those benefits will accrue at zero cost to non-participants.

20 **V. LEGACY RIGHTS FOR DG CUSTOMERS**

21 **Q. PLEASE DESCRIBE WHAT YOU MEAN BY THE TERM "LEGACY RIGHTS."**

22 A. I use the term "legacy rights" in a manner synonymous with the term "grandfathering."
23 Either term refers to a policy that provides a guarantee to customers that they will be

1 permitted to continue taking service under a given tariff structure for a specified period of
2 time, or in perpetuity, even after that tariff or tariff structure is closed to new customers. In
3 the present context, legacy rights would have two aspects, because DG customers
4 effectively take service under two rate schedules. One, they typically take service under
5 Schedule RNR, including the monthly netting option. Two, they take electric supply
6 service under one of the otherwise applicable rate schedules available to all customers
7 within their respective customer class.

8 Legacy rights, in typical practice, run with the system rather than with the original
9 installing customer, such that they remain available to a subsequent customer should the
10 user of the system change (e.g., a home with a solar system is sold to a new resident).

11 **Q. DOES THE ESTABLISHMENT OF LEGACY RIGHTS TYPICALLY HAVE THE**
12 **EFFECT OF FIXING ACTUAL RATES FOR QUALIFYING CUSTOMERS?**

13 A. No. As typically applied, a customer that is granted legacy rights is permitted to continue
14 to take service under an otherwise available rate schedule (e.g., Schedule R), but would be
15 subject to any generalized changes to that rate schedule. In other words, any changes to
16 Schedule R would apply equally to both DG and non-DG customers. An exception to this
17 could apply where a DG tariff is structured with a rate for exports to the grid that is different
18 than what a customer pays for electricity from the grid. Under an “export rate” structure,
19 the export rate itself might be fixed for a specified period of time upon the customer’s
20 enrollment. This is commonly referred to as a “lock-in.”

1 **Q. PLEASED DESCRIBE THE POLICY RATIONALE FOR ESTABLISHING**
2 **LEGACY RIGHTS FOR DG CUSTOMERS.**

3 A. It is reasonable to assume that a customer considering installing a DG system would,
4 among other considerations, weigh the potential financial benefits of such an investment
5 over its anticipated lifetime against the upfront costs of installing the system. DG systems
6 typically involve a substantial upfront cost, with financial benefits accruing over the life of
7 the system in the form of offsetting electricity purchases from the utility.

8 It is also reasonable to assume that a prospective DG customer, like most utility
9 customers, should anticipate changes to certain rate components over time. Customers are
10 accustomed to and generally accept that periodic and typically gradual rate changes will
11 occur. That is, customers have an expectation based on decades of ratemaking that they are
12 likely to experience relatively small rate changes from year to year (i.e., typical increases
13 in existing rate components) rather than dramatic changes in rates or rate structure. This
14 expectation is in large part attributable to the fact that utility regulators have historically
15 made substantial efforts to avoid “rate shock” in ratemaking decisions, consistent with the
16 principle of gradualism.

17 **Q. IS THERE ANY COROLLARY TO DG CUSTOMER LEGACY RIGHTS IN THE**
18 **REALM OF UTILITY COST RECOVERY?**

19 A. Yes. GPC enjoys a type of legacy rights for its own investments. For instance, once a new
20 generation investment has been determined to be prudent, the Commission has not
21 historically taken actions that compromise the recovery of that investment assuming that
22 the Company operated the unit responsibly. Even if an investment becomes uneconomical

1 to operate for its full expected lifetime, the Company would typically still be permitted to
2 recover its full capital costs and potentially a full equity return.

3 The Commission's establishment of the Schedule RNR monthly netting option was
4 akin to a determination of prudence since it signaled to customers that DG might be a
5 reasonable investment to make. After all, in the mind of a prospective DG customer, why
6 would the Commission establish such a program that supports and promotes DG
7 investments and then eliminate it or modify it in such a way that renders those investments
8 severely compromised? Establishing legacy rights for DG customers would treat their
9 investments as equivalent to those the Company makes.

10 **Q. HAVE OTHER STATE PUBLIC SERVICE COMMISSIONS ADDRESSED**
11 **LEGACY RIGHTS FOR EXISTING NET METERING CUSTOMERS?**

12 A. Yes, within the spectrum of recent regulatory decisions affecting net metering and DG
13 customer rates, legacy rights is perhaps the single most consistent element. I have
14 developed a table, attached as Exhibit JRB-5, that provides an overview of how other state
15 utility regulatory commissions have addressed legacy rights for existing DG customers in
16 their consideration of changes to net metering and/or rate structures for those customers.
17 As Exhibit JRB-5 shows, while there are some small differences in how states have
18 approached legacy rights, there are common conclusions as well. The dominant
19 conclusions with respect to legacy rights are as follows:

- 20 • While certain elements vary from state to state, as a general policy principle, legacy
21 rights have broad support from regulators.
- 22 • The most common legacy period duration is at least 20 years, ranging upward to
23 indefinite in some states.

- Legacy rights eligibility is based on a customer submitting an application either before some future benchmark or date certain, or the date of a decision.
- Legacy rights under a modified net metering policy or net metering successor policy tend to mirror the legacy rights period under the original net metering policy, or have slightly shorter time periods, although some states have not yet addressed this.

Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION FOR THE ESTABLISHMENT OF LEGACY RIGHTS FOR GPC'S DG CUSTOMERS?

A. I recommend that customers enrolled in the Schedule RNR monthly netting option (and any potential future successor) be granted a legacy rights period of at least 20 years, and that these rights run with the DG system through any changes in ownership. The Commission could reasonably extend that period to the lifetime of the system in order to make it equivalent to the certainty that the Company enjoys for its own investments. Legacy rights should be applied to both:

- (a) the applicable DG service schedule (e.g., the Schedule RNR monthly netting option), and
- (b) the customer's choice of base rate schedule from any qualifying rate schedules available to non-DG customers.

Q. ARE THERE ANY OTHER ELEMENTS OF LEGACY RIGHTS THAT YOU RECOMMEND THE COMMISSION ESTABLISH?

A. Yes. Customers should be permitted to:

- (a) add storage to an existing system without jeopardizing the legacy period that applies to that system, and

1 (b) make repairs or equipment replacements to an existing legacy system that do
2 not materially change its generating capacity without forfeiting the legacy period
3 that applies to that system. For the purpose of defining a material change in system
4 size, I recommend that the threshold be set at the greater of 1 kW or 10% of original
5 nameplate capacity.

6 **Q. PLEASE EXPLAIN WHY ALLOWING STORAGE ADDITIONS TO LEGACY**
7 **SYSTEMS IS JUSTIFIED.**

8 A. The addition of storage does not increase the generating capacity of a DG system.
9 Moreover, battery-paired systems provide additional benefits to the customer, in the form
10 of greater resiliency and potential cost savings, while also making a DG system capable of
11 generating greater value for the broader grid. As it is a win-win for both the customer and
12 the broader grid, existing DG customers should be encouraged to add storage, and part of
13 that encouragement means eliminating potential barriers, such as the forfeiture of legacy
14 rights.

15 **Q. PLEASE EXPLAIN WHY SMALL CHANGES IN SYSTEM SIZE SHOULD BE**
16 **PERMITTED WITH A SYSTEM'S LEGACY PERIOD.**

17 A. This element is necessary to allow customers to make system repairs or equipment
18 replacements during the system lifetime. It is not uncommon that an equipment
19 replacement (e.g., to an inoperable panel or inverter) cannot be accomplished on a 100%
20 like-for-like basis for a variety of reasons. For instance, the existing equipment model may
21 no longer be in production, or may have changed in terms of dimensions or capacity rating.
22 Allowing a small amount of sizing flexibility permits the customer to select the best
23 replacement option without fear of negative consequences.

VI. CONCLUSION

Q. DO YOU HAVE ANY CLOSING REMARKS TO MAKE TO THE COMMISSION ON THE MATTERS THAT YOU HAVE ADDRESSED IN YOUR TESTIMONY?

1. Due to the mechanics of the earnings and sharing mechanism and GPC's pattern of consistent and persistent overearning, non-DG customers are indifferent to further DG deployment – unless the Commission adopts the Company's proposed DG revenue erosion rate adjustment. Absent approval of this proposed adjustment, they would not be allocated any additional costs or otherwise pay higher rates as a result of residential DG deployment.
2. The Company's analysis of the projected amount of revenue erosion associated with residential DG is wholly unreliable due to both a very basic calculation error and numerous inaccurate assumptions incorporated into the modeling. The calculation error alone increases the Company's revenue erosion estimate by 63% (\$533/customer per year) and fully correcting the other flawed assumptions I identified would reduce the estimated revenue erosion by at least 10% more.
3. It is undeniable that the Company's proposal to require customers that enroll on Schedule RNR on or after January 1, 2023 to take electricity service under Schedule TOU-RD will severely reduce residential customer opportunities to deploy DG. All prospective DG customers would see significant declines in their DG savings rate as a result of the Company's proposals. However, the full impacts of the Company's

1 proposals on DG opportunities will not be evenly distributed. The customers that would
2 experience the most detrimental impacts are customers with relatively lower pre-solar
3 usage, because for these customers, Schedule TOU-RD is punitive in and of itself.

- 4 4. As I have demonstrated using the Company's own modeling (with a significant error
5 corrected), the collective effect of Schedule TOU-RD is to reduce net customer savings
6 for lower usage customers to near zero relative to taking Schedule R service and not
7 installing DG. This is represented by a total annual net cost savings of only \$50 - \$100
8 for an average size (4.9 kW) solar system depending on whether monthly netting or
9 instantaneous netting is used, equivalent to a DG savings rate of 0.7 – 1.5 cents/kWh.
10 In either case, such low savings will undeniably place DG entirely out of reach for these
11 types of customers, who are likely to skew towards the less affluent end of the spectrum
12 of DG customers. At the same time, the Company's own modeling illustrates that these
13 customers:

14 (a) are likely less costly to serve since their load profile shows peak demands
15 occurring exclusively during off-peak and super off-peak periods, and

16 (b) produce less revenue erosion, or cost shift from the Company's perspective, on
17 an absolute basis (\$/customer per year) and on solar capacity basis (\$/kW of
18 installed solar per year).

19 The Commission can address all of these issues by denying the Company's
20 mandatory Schedule TOU-RD proposal, adopting my proposal for expanding the monthly
21 netting cap, and denying the Company's requested DG revenue erosion adjustment. All of
22 these actions can be taken without appreciably affecting the Company's opportunity to earn

1 a reasonable rate of return on its investments and recover its costs of providing service to
2 customers.

3 **Q. PLEASE PROVIDE A SUMMARY OF YOUR SPECIFIC RECOMMENDATIONS**
4 **TO THE COMMISSION ON DG-RELATED ISSUES.**

5 A. I recommend that the Commission take the following actions on the Company's DG
6 proposals and other matters related to DG policy and rates:

- 7 • Deny the Company's request to require future residential Schedule RNR customers to
8 take service under Schedule TOU-RD.
- 9 • Deny the Company's request for a monthly netting revenue erosion adjustment.
- 10 • Expand the cap of the Schedule RNR monthly netting option to 3% of the Company's
11 2021 peak load.
- 12 • Require residential customers that enroll in the expanded monthly netting option to pay
13 a minimum monthly bill of \$22.34/month, equivalent to the residential class's
14 customer-related unit cost.
- 15 • Establish legacy rights for both current and future Schedule RNR systems for a term of
16 20 years or longer that allow qualifying customers to: (a) remain on the DG tariff option
17 of their choice (e.g., monthly netting), and (b) take electricity service under any rate
18 otherwise available to non-DG customers within their rate class.
- 19 • Establish that legacy rights are not affected by either: (a) the subsequent addition of
20 battery storage to a system, or (b) system repairs or equipment replacements that
21 increase the generating capacity of the system by no more than the greater of 1 kW or
22 10% of its originally installed capacity.

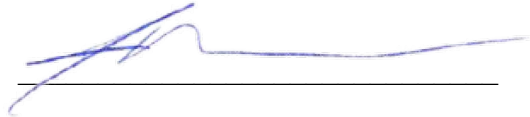
1 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

2 A. Yes.

[Remainder of page intentionally left blank.]

CERTIFICATE OF SERVICE

I certify that the foregoing **Supplemental Direct Testimony of Justin Barnes on behalf of Georgia Interfaith Power & Light** was filed in Docket No. 44280 with the Public Service Commission by electronic delivery on the 18th of November, 2022. An electronic copy of same was served upon all parties listed below by electronic mail as follows:



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1 (The documents referred to were marked for
2 identification as GIPL Exhibits 11 and 12.)

3 MS. WHITFIELD: Madam Chair, with your
4 permission, I would like to ask Mr. Barnes to read
5 his summary.

6 MADAM CHAIR PRIDEMORE: Go ahead, Mr. Barnes.

7 MR. BARNES: Good morning, Madam Chair and
8 Commissioners. I appreciate the opportunity to be
9 back here today. I fundamentally disagree with the
10 company's recommendations on monthly netting and rate
11 design for rooftop solar customers on the schedule
12 RNR tariff. At its core, this is a matter of
13 customer rights. Customers should be able to use
14 less electricity and save money on bills if they
15 choose to do so. The company is not guaranteed a
16 certain amount of revenue from any particular
17 customer or group of customers.

18 The company's proposals characterize all
19 customer cost savings, including savings resulting
20 from simply buying less of the company's product, as
21 a cost shift. But a cost shift does not occur just
22 because the company collects less money from a
23 particular customer than it did in prior years or
24 months or that it forecasts it might collect in
25 future time periods.

1 Revenue erosion is not the same thing as cost
2 shifting, despite the company's efforts to conflate
3 the two terms.

4 The Commission should evaluate the company's
5 revenue from a perspective that considers the
6 aggregate effect of numerous potential sources of
7 revenue variations that affect revenue in either a
8 positive or negative direction.

9 For example, in any given year, there may be
10 some customers that generate less revenue than
11 expected due to DG, efficiency measures, behavioral
12 changes, or rate switching. And others that generate
13 more revenue due to factors like weather, lifestyle,
14 and behavioral changes, and appliance
15 electrification.

16 Does it really make sense for the company to
17 claw back customer savings attributable to one factor
18 while at the same time letting it keep excess amounts
19 that arise from other factors? Doing so not only
20 exacerbates the company's consistent over-earnings,
21 it actually creates the purported cost shift itself.

22 In addition to inappropriately conflating
23 revenue erosion and cost shifting, the company's own
24 cost shift analysis contains significant errors and
25 flawed assumptions that dramatically overstate the

1 estimated revenue erosion associated with rooftop
2 solar customers.

3 For example, as discussed in my testimony and
4 reflected in my demonstrative, a simple spreadsheet
5 error caused the company to overstate the alleged
6 cost shift by more than \$500 per customer per year,
7 or 63 percent. The company has acknowledged this
8 error. But even with this corrected, the company's
9 analysis contains further erroneous modeling
10 assumptions that also cause the amount of customer
11 savings or revenue erosion to be overstated.

12 These include assuming a due south system
13 orientation, which is impractical because such
14 optimal orientation of a home's roof is rare; and
15 using first-year solar production values, which fails
16 to account for unavoidable declines in panel output
17 over time.

18 In total, these and other flawed assumptions I
19 identified likely cause the company to overstate
20 revenue erosion by an additional 10 to 20 percent.
21 Therefore, beyond the matter of the actual effect of
22 revenue erosion, the company's revenue erosion
23 estimates themselves are simply not credible.

24 For these reasons and others addressed in
25 greater detail in my testimony, I make several

1 recommendations to the Commission. First, I
2 recommend that the Commission reinstate schedule RNR
3 monthly netting with two key guardrails in place.
4 One, limit participation in the monthly netting
5 program to 3 percent of the company's 2021 peak load.
6 The Commission could revisit and reassess the program
7 when participation approaches or reaches that limit.

8 Two, require customers that participate in the
9 expanded monthly netting option to pay a minimum bill
10 of \$22.34 per month, which is equivalent to the
11 residential class customer-related unit cost
12 according to the company's cost of service study and
13 several dollars per month higher than the effective
14 minimum bill for non-RNR residential customers.

15 Second, I recommend that the Commission reject
16 the company's proposal to require all future schedule
17 RNR customers to take service under its complicated
18 three-part demand charge tariff, schedule TOU-RD.

19 At the November hearing, I, along with staff
20 and other intervenors, provided substantial evidence
21 demonstrating that mandatory demand charge tariffs
22 are unsuitable for residential customers. To wit:
23 That they are misaligned with cost causation
24 generally for most residential customers and
25 particularly so for customers with lower average

1 energy usage.

2 The same reasoning applies here. Furthermore,
3 my testimony provides additional analysis
4 illustrating why this proposal is a bad idea for
5 rooftop solar customers. Among other things, that it
6 would be the most punitive on those customers that
7 cause the least amount of revenue erosion as
8 indicated by the company's own analysis.

9 Finally, I recommend that the Commission
10 establish legacy rights for current and future
11 schedule RNR systems for a term of 20 years or
12 longer, which permit those systems to remain on the
13 DG option of the customer's choice and allow the DG
14 customer to take service under any rate otherwise
15 available to non-DG customers within their rate
16 class. Such a policy would be consistent with the
17 national landscape of DG policy and consistent with
18 how the company's own generation investments are
19 treated.

20 That concludes my summary. I look forward to
21 answering your questions.

22 MADAM CHAIR PRIDEMORE: Questions from
23 Commissioners?

24 (No response.)

25 MADAM CHAIR PRIDEMORE: Okay. Take it from the

1 top. Americans for Affordable Clean Energy?
2 (No response.)
3 MADAM CHAIR PRIDEMORE: Americans for
4 Affordable Clean --
5 MR. GALLOWAY: No questions, Madam Chair.
6 MADAM CHAIR PRIDEMORE: Okay. Georgia
7 Coalition of Local Government?
8 MS. BROWN: No questions, Madam Chair.
9 MADAM CHAIR PRIDEMORE: GA Solar?
10 MR. MORELAND: No questions.
11 MADAM CHAIR PRIDEMORE: GASEIA?
12 MR. THOMASSON: No questions.
13 MADAM CHAIR PRIDEMORE: Sierra Club?
14 MS. ARIZA: No questions.
15 MADAM CHAIR PRIDEMORE: MARTA?
16 MS. STURM: No questions.
17 MADAM CHAIR PRIDEMORE: SACE and Southface?
18 MR. DOWDY: No questions.
19 MADAM CHAIR PRIDEMORE: Georgia Public Service
20 Commission?
21 MR. THOMAS: No questions.
22 MADAM CHAIR PRIDEMORE: Georgia Power?
23 MR. HEWITSON: Thank you, Madam Chair.
24 CROSS-EXAMINATION
25 BY MR. HEWITSON:

1 Q Mr. Barnes, good to see you again.

2 A Likewise.

3 Q Your argument that revenue erosion is not a
4 cost shift is based on the company's recent history of
5 earning within the approved earnings band; is that right?

6 A Well, not entirely. It -- when we consider,
7 say, within a given rate plan, like, say, the one adopted in
8 2019, for one, we know that there is no cost shift, there
9 are no costs being shifted to other customers because, you
10 know, they haven't changed the rates yet. You know, nothing
11 has -- nothing has happened to change the rates.

12 Now, with the company's current base rates
13 proposal, the company has proposed a uniform percentage
14 increase across the board for all customer classes. Also,
15 meaning that there is nothing being shifted onto, you know,
16 say customer -- other non-participant customers within the
17 residential class or shifted in between classes because
18 the -- you know, the rate increase is uniform.

19 The only, you know, cost shift that is present
20 is when, you know, as the company proposes, to collect this
21 \$1.4 million in revenue erosion by allocating that on top
22 of, you know, basically, the results of their
23 cost-of-service study.

24 Q Okay. And your position, as you discuss on
25 page 9, line 17 to 25 of your rebuttal testimony, is that as

1 long as the company earns above the ROE set point, any
2 revenue not collected from RNR customers should be the
3 responsibility of the company, not other customers?

4 A In the kind of consistent over-earnings
5 environment? Yeah, I think that's kind of poetic justice.

6 Q Okay. Looking at your hypothetical example on
7 page 8, lines 5 through 9, you include two assumptions. The
8 first is that DG customers avoid paying some charges that
9 they otherwise would have paid if they did not have
10 behind-the-meter solar, and the second is that the company
11 earns above the ROE set point; right?

12 A Right.

13 Q In rate cases when revenue requirements are
14 set, a utility can forecast the first assumption; right?
15 They can look at how many behind-the-meter solar customers
16 there are on the system and anticipate on a weather-normal
17 basis what sales and solar production will be; right?

18 A They can make an estimate. Whether it's going
19 to be a good estimate is another question.

20 Q But the revenue requirements are set based on
21 the ROE set point, not higher or lower; right?

22 A Right.

23 Q So in a rate case, when setting revenue
24 requirements and designing rates, your first assumption
25 about the production from solar can be accounted for, but

1 your second assumption, by design, is not assumed; right?

2 A Sorry. My second assumption --

3 Q Your second assumption, that the company will
4 over-earn or will earn above the ROE set point, that's
5 actually not the assumption in rate cases. The assumption
6 is that you will recover the revenue requirements?

7 A I think it is reasonable to assume that the
8 company would continue to over-earn given the recent history
9 of it doing so. You know, when we see a pattern, we can --
10 we can identify it for what it is. But, yes, the assumption
11 in setting rates would be that, no, you know, the revenue is
12 going to produce the rate of return on which, you know, the
13 company -- that the company was approved to receive.

14 Q Right. And that's because the rates are
15 designed to recover that revenue requirement alone; right?

16 A That's right.

17 Q So because behind-the-meter solar customers are
18 expected to buy less during the rate recovery period, more
19 costs are designed to be recovered through rates from other
20 customers. Isn't that the -- how that ends up working?

21 A If -- if you have adjusted billing determinates
22 in order to reflect that, then, yes, you know, the company's
23 proposed adjustment is the -- is the way that is
24 effectuated.

25 Q Now, back to the revenue erosion itself. You

1 say that it's not a cost shift as long as the company earns
2 above the ROE set point; right?

3 A Well, I think I've kind of already answered
4 this. It's not a cost shift currently. It's not a cost
5 shift under the company's proposal. It would only be a cost
6 shift if other customers are actually being held responsible
7 for what DG customers aren't paying.

8 Q Now, the company's earnings are dependent on
9 more than just revenue collected. You would agree with
10 that; right?

11 A Certainly.

12 Q Okay. And so would you agree that if -- that
13 it would be a cost shift in your viewpoint, under your
14 viewpoint, that the company earned below the ROE set point,
15 like it happened -- like what happened in 2009 and 2010?

16 A There would a potential for a cost shift.
17 Whether or not, you know -- the magnitude of that, in which
18 direction it operates and whom it affects, are kind of
19 questions that I -- I probably can't -- I can't answer. But
20 there would be the potential for that to occur.

21 Q Does it seem logical to you that whether
22 something is identified as a cost shift depends in part on
23 whether the company earned above or below the ROE set point,
24 which, as we've just discussed, is dependent on factors
25 other than just revenue?

1 A I'm sorry. Could you repeat that?

2 Q Does it seem logical to you that whether
3 something is identified as a cost shift depends on whether
4 the -- a company earned above or below the ROE set point,
5 which can be affected by many considerations, not just
6 revenue?

7 A Well, I would say it would be -- within a rate
8 period, there could only be a cost shift if the company were
9 to earn below the lower band and then come back in and
10 request a rate increase, you know, which presumably
11 addresses, you know, revenue erosion of one type or another
12 from multiple sources.

13 Q Do you agree with me that the cost to serve an
14 RNR customer is the same regardless of whether that RNR
15 customer is in the monthly netting pilot or is part of RNR
16 instantaneous?

17 A All other things being equal, yeah. But
18 whether or not the customer is kind of behaving differently
19 because they are subject to a different DG tariff regime,
20 you know, it's certainly plausible that a customer might
21 kind of change the way they -- change the way they live,
22 change their lifestyle a little bit if, you know, they're
23 getting monthly netting versus they're getting instantaneous
24 netting.

25 But all other things being equal, yeah, like,

1 you could assume kind of like no difference assuming they
2 don't change their behavior.

3 Q What type of lifestyle change do you think a
4 customer might have if they're getting monthly netting
5 rather than instantaneous?

6 A Well, I mean, presumably, they would be
7 incentivized under instantaneous to try to reduce the amount
8 of exports that they produce, because those receive lower
9 value. That might ultimately kind of result in increasing
10 demand during certain times and reducing demand during other
11 times. A customer on monthly netting, you know, may or may
12 not behave in exactly the same way. Whether or not they're
13 practically able to kind of create a significant effect is
14 another question. But they might. You know, it's
15 plausible; they could try. If they have storage, they might
16 do better at it.

17 Q So would the opposite of that be true, if a
18 customer is on monthly netting they may be incentivized to
19 increase the amount that they export so that they can get
20 that benefit?

21 A I don't know that they are incentivized to
22 increase the amount they export. It doesn't really -- like,
23 they get the same benefit whether they use it directly on
24 site or whether they export it. They're kind of indifferent
25 as to whether or not they're exporting it, whereas, the

1 instantaneous netting customer is not indifferent because
2 they receive a different rate.

3 Q But regardless of whether a customer is on RNR
4 instantaneous or RNR monthly netting, the customer's need
5 for and reliance on Georgia Power's electric system tends to
6 be the same; right?

7 A Like all other things being equal, yeah, more
8 or less the same.

9 MADAM CHAIR PRIDEMORE: Mr. Hewitson, I have a
10 genuine engineering question.

11 MR. HEWITSON: You're not going to ask me that,
12 are you?

13 MADAM CHAIR PRIDEMORE: So -- I'll take it
14 really from either of you that will -- that can
15 answer this. How do -- how do you change behaviors?
16 You can't stop the sun. You're not going to move the
17 system or the panels. I don't understand why a
18 behavior would change whether or not you're on --
19 which of the two tariffs. I mean, I just -- that's
20 an engineering --

21 MR. HEWITSON: That's why I asked the question
22 to Mr. Barnes. I think Mr. Barnes might want to try
23 his answer again.

24 A Sure. Yeah. I can explain. You know, in a
25 hypothetical where you're under monthly netting, you know,

1 you don't -- you don't really have any incentive or
2 disincentive to avoid exports.

3 Under instantaneous netting, you do, because
4 you get, you know, a much lower value for what you export,
5 rather -- you know, relative to the retail value that you
6 get when you essentially avoid consumption on-site.

7 So what you might do is, you know, decide to
8 run your dryer during the day, on a weekend or something, so
9 that you're using electricity that, you know, would
10 otherwise might be exported to the grid, you're using it
11 directly on-site and accomplishing something useful for
12 yourself.

13 So it would basically just be like shifting
14 load into the good solar production window in order to avoid
15 the diminishment in value that you receive from exports.

16 I kind of doubt that a customer is really going
17 to be able to do that very consistently, but it's plausible
18 that they could try.

19 MADAM CHAIR PRIDEMORE: Okay.

20 VICE CHAIRMAN ECHOLS: Madam Chair, I'll give
21 you an example, you know, of my own, you know, the
22 way that I do this. If you -- I have net metering
23 with Jackson EMC, but if I didn't, I would charge my
24 electric car, you know, during a time-of-use period
25 to keep from spilling the power back onto the grid or

1 putting it back onto the grid since I was getting
2 compensated less for it. It would be better for me
3 to consume it myself than give it back to the company
4 at the lower amount.

5 So that's -- that's an example of how it would
6 change your behavior from charging your car in the
7 afternoon to charging your car in the evening.

8 MADAM CHAIR PRIDEMORE: I'll take your -- I'll
9 take your word for it.

10 Go ahead.

11 BY MR. HEWITSON:

12 Q One the examples you gave, Mr. Barnes, was that
13 a customer, an RNR customer might choose to use electric
14 appliances, like, run the dryer during the day when they're
15 producing a lot. That was one of your examples?

16 A That's -- you know, that's one hypothetical
17 that -- you know, one thing you could try, I suppose.

18 Q So an RNR customer in your view would be able
19 to have that knowledge, but yet you have testified that,
20 under the TOU-RD, customers don't understand enough to be
21 able to run their dryer at certain times or not run their
22 dryer at certain times?

23 A Well, it's a different question.

24 Q You're right.

25 A You know, because, one, if you were -- if you

1 were to do that in order to avoid exporting excess to the
2 grid, you don't have to do that consistently throughout the
3 month every day every hour in order for it to be beneficial
4 to you. All you have to do -- you know, it's your -- it's
5 kind of one and done. You avoided exporting something
6 that's going to get three cents, and instead redeemed value
7 of ten cents.

8 That's an entirely different kind of action
9 than continually policing your demand during every single
10 hour of every single month and not being -- having the
11 benefit of being able to kind of just, like, look outside or
12 look at your phone and look and see what your solar system
13 is producing. You don't know what the collective demand of
14 all of the other things that are running in your house is at
15 any given time.

16 Q But you would need to know what the collective
17 demand is to know whether you're going to end up exporting.
18 You would have to know how much you're using, how much
19 you're producing to know whether to run your dryer at that
20 time or not. So it's actually more difficult to prevent
21 exports --

22 A No, it's not.

23 Q -- than it is to know that you're not -- you
24 should not run multiple electrical appliances at the exact
25 same time; right?

1 A So if you -- well, if you run your dryer when
2 you're already importing electricity, even if you think that
3 you might have been exporting, you're no worse off. You
4 were going to run your dryer anyway. You're going to pay
5 the same amount. But you are no worse off than you would be
6 had you not attempted to do that.

7 With TOU-RD, you are worse off that one hour
8 where you, you know, through inattention or lack of
9 knowledge, manage to register a high demand through the kind
10 of collective operation of multiple devices at the same
11 time, some of which you might be monitoring actively, others
12 of which you aren't.

13 Q Do you think it's easier -- or you think it's
14 easier to know how much a house is consuming and how much
15 solar panels are producing to know whether there is going to
16 be an import or export at that -- in that particular hour
17 than it is to know, I don't run the dryer, the dishwasher,
18 air-conditioning, and a bunch of other things all at the
19 same time during the day?

20 A The former is very much easier because you can
21 look outside and see that it's sunny. You can look at your
22 phone oftentimes and see what your system is producing. You
23 don't know what all of those things are -- you know, all of
24 those appliances are doing at the same time, nor do you have
25 the mental ability to process it even if you did know and

1 react to it.

2 Q All right. Back to the RNR customers monthly
3 and instantaneous both relying on the electric system. Do
4 you agree with me that any benefits from customer generation
5 conferred to Georgia Power and other customers are the same
6 regardless of whether the RNR customer is netting on a
7 monthly or instantaneous basis?

8 A Yeah. I mean, all other things being equal,
9 you know, the value of solar is kind of -- kind of is what
10 it is. There could be some variations like -- like
11 distribution load pockets, that kind of thing, but that's
12 not -- you know, that's not something that changes based on
13 the tariff.

14 Q Okay. So all other things being equal --
15 because, like you said, there are, I guess, some minor
16 considerations -- the only difference between RNR monthly
17 and RNR instantaneous is that Georgia Power collects less
18 revenue from the monthly netting customers; right?

19 A Yes. I mean, via, you know, via providing
20 less -- the other impact is that, you know, they -- you
21 know, those customers on RNR instantaneous pay more so...

22 Q And that's true even though the cost to serve
23 the customer and the benefits conferred by that customer are
24 the same whether they are on instantaneous or monthly
25 netting?

1 A That would be correct, yeah.

2 Q You propose a minimum bill requirement, and you
3 propose that RNR monthly netting customers be subject to a
4 minimum bill requirement of \$23.34 a month; right?

5 A That's 22 --

6 Q 22. I'm sorry. I -- it says that. I just
7 read it wrong. Thank you.

8 Your intent in proposing the monthly minimum
9 bill is to ensure that RNR customers fairly contribute to
10 the recovery of costs that they cause on the system; right?

11 A Well, most specifically that they pay for a
12 portion of costs under an assumption that DG is not capable
13 of avoiding all -- all aspects of distribution system
14 investment.

15 Q So you recognize that the monthly netting
16 customers may not always pay their fair share of the cost;
17 right?

18 A Yeah, I recognize that -- I recognize that for
19 any customer.

20 Q All right. Now, the amount that you suggest,
21 the \$22.34 a month, is based on the customer-related costs
22 for the residential class found in the company's cost of
23 service study; right?

24 A Right. Which include a fairly sizable
25 percentage of shared distribution investment as

1 customer-related.

2 Q Yeah. But it doesn't include all of the
3 distribution-related cost; right?

4 A Right.

5 Q I recognize that you disagree with it in your
6 other testimony, but you included it for this figure; right?

7 A Understood. Yeah. I don't remember the exact
8 percentage, but it's, you know, it's -- it's approximately,
9 I think, 50-50. It's close to that.

10 Q All right. Your proposed amount includes
11 the -- well, we just said that.

12 The customer-related -- it's the
13 customer-related distribution costs, not the demand-related
14 distribution costs. Right? And you were saying that's
15 about 50-50?

16 A Well, yeah, that's right, except, you know, my
17 view is that all of those costs should be considered
18 demand-related, so kind of in effect, it's collecting
19 50 percent of distribution demand-related costs from my
20 perspective on how customer-related and demand-related
21 should be defined.

22 Q Monthly netting customers use the system any
23 time they do not self-generate 100 percent of their own
24 needs; right?

25 A They do.

1 Q And for most RNR customers there are only a few
2 hours in the day, if at all, that they generate all of their
3 own needs; right?

4 A Well, I mean, I don't know -- it depends on how
5 you define "a few." I don't know. It's certainly, like, a
6 part of the day during which they could possibly -- how many
7 hours that is, you know, it's some.

8 Q I will go with some.

9 A Okay.

10 Q But under your minimum bill proposal, monthly
11 netting customers with a net bill of zero kilowatt hours in
12 a month would not contribute any amount towards the
13 demand-related distribution costs; right?

14 A Well, they would be kind of contributing
15 in-kind insofar as when they're exporting electricity,
16 they're reducing demand on the company's system, and,
17 therefore, providing something of value to the company and
18 to other customers. So even if it is not, say, a monetary
19 contribution, that's not to say that there isn't kind of
20 a -- a transaction of value for something valuable taking
21 place.

22 Q But if all they're doing is paying the basic
23 service charge portion of the distribution system and
24 they're using it the majority of the hours, they're not
25 paying for those hours for the distribution-related costs

1 outside of the basic service charge; right?

2 A They're paying by, like I just said, providing
3 an in-kind service.

4 Q Okay. Let me put it this way: They're not
5 making any cost contribution through monetary means for the
6 costs that have already been identified through the
7 cost-of-service study for that year. Right? Or for that
8 month?

9 A They aren't contributing monetarily. They are
10 contributing something else of value, which is avoidance of
11 future investment costs.

12 Q Your monthly minimum bill does not include
13 transmission-related costs identified in the cost-of-service
14 study; right?

15 A No, it doesn't.

16 Q But the transmission system delivers energy to
17 the homes at night and during the day when they don't meet
18 100 percent of their needs; right?

19 A That's right. But again, you know, customers
20 are still contributing something of value by reducing load
21 on the transmission system when they are either generating
22 and using consumption behind the meter or exporting, to the
23 extent that it doesn't go back to the transmission system.

24 I mean, it's kind of the same across all levels
25 of the system. It's not a monetary transaction, but it is a

1 transaction, an exchange of a product of value.

2 Q Yes. But there's a difference between reducing
3 your use and not paying for your use; right? Would you
4 agree with that?

5 A I might --

6 Q Okay. Let me put it this way: There's a --
7 your value that you are ascribing to them is that they're
8 reducing use on the system, on the transmission system, by
9 self-generating some of their own energy; right?

10 A That's right.

11 Q Okay. But in the hours that they're not
12 self-generating, at night, for instance, when they're using
13 the system, there's no contribution in kind in that way, is
14 there?

15 A No. There's not. There's no contribution
16 during those hours, but you don't necessarily have to
17 contribute during all hours of the day in order to provide
18 an equivalent contribution, you know, over the course of an
19 entire day.

20 Q Right. But in a month where they have a zero
21 kilowatt hour bill, they don't contribute under your monthly
22 minimum bill proposal to any of those transmission-related
23 costs, despite the fact that they do use the transmission
24 system during the month; right?

25 A They contribute by reducing their load and

1 providing a valuable export to the system in a way that, you
2 know, may or may not match exactly what costs are caused by
3 using the system, but which we don't -- would don't know the
4 answer to that, but at the end of the day, again, it's this
5 kind of -- it's almost like a bartering transaction.

6 You don't -- you know, you don't have to pay
7 for what you are using during every hour as long as you --
8 when you are providing that service, you provide it at a
9 greater rate than what you were using at those other hours.

10 It can equal out throughout the course of --
11 like, if I pay you -- if I pay you one cent every hour, I
12 pay you 24 cents over the course of the day. I can equal
13 that out if I just give you 24 cents during one hour.

14 Q That assumes, though, that the value of their
15 export or the value of their reduction includes those
16 transmission-related costs; right?

17 A Well, that -- yeah, that -- that assumes that
18 there is something of value that they are providing through
19 the reduction of load on the transmission system.

20 Q Okay. In your Exhibit JRB-5, you identify the
21 legacy rates for existing DG customers in 17 other states;
22 right?

23 A That's right.

24 Q Okay. And legacy rates are being established
25 in those states because those states are retreating from net

1 metering or preparing to retreat from net metering; right?

2 A Not all of the legacy rates are actually kind
3 of associated with, say, like, eliminating net metering.
4 Some of them are -- like, if you look at New Hampshire, New
5 Hampshire still has net metering. It is kind of -- evolving
6 net metering, I think, would probably be the -- or evolving
7 DG rates would probably be a more accurate description.

8 Q I guess to put it a different way, they are
9 changing their net metering policies in a way that current
10 net metering customers view as unfavorable, which is why
11 they are establishing the legacy rates. Would that be a
12 fair way of putting it?

13 A It's not necessarily true that it's going to
14 always be, you know, unfavorable. For instance, I mean, you
15 can say -- you could say, like, require customers to take
16 service under a TOU rate.

17 Now, not all customers are necessarily going to
18 want to do that, but some customers might. Some customers
19 might, in fact, be better off. You know, so it's really --
20 I would say it's more of a question of respecting their
21 expectations that they would have all of these choices that
22 they formerly had. You know, in some cases, yes, there's
23 kind of like a diminishment in value, but that isn't
24 necessarily always the case.

25 Q And many of these states are changing their net

1 metering policies because they recognize a cost shift is
2 happening between participants and nonparticipants; right?

3 A In some cases, yes, they have recognized the
4 cost shift. In other cases, they've been directed to, you
5 know, make some change by the legislature. You know, point
6 me to specific states and I'm kind of totally willing to
7 discuss what might have been found in those individual
8 states.

9 Q Okay. In Arizona, the Commission has ordered
10 that the export rate be phased down to avoided cost; right?

11 A Well, yeah, the solar -- you know, starting
12 with kind of like this resource comparison proxy, the solar
13 avoided cost, which is based on the, basically, what
14 utilities purchase utility-scale solar power at. But, yes,
15 eventually kind of -- well, in theory, it's supposed to go
16 to an administratively-determined value of solar rate that's
17 really focused, not on past costs with utility scale
18 projects, but is focused on, you know, marginal
19 forward-looking cost, like value of solar.

20 Q Sort of like the renewable cost benefit
21 framework like we have here in Georgia, that is the solar
22 avoided cost?

23 A I'm not super familiar with the renewable cost
24 benefit framework in Georgia as it applies to, say,
25 behind-the-meter systems. But, like, conceptually, I would

1 say they're kind of the same. Whether they include all of
2 the same elements, I -- I can't say for certain.

3 Q I'm not saying they're equivalent. I'm saying
4 that when you say that they're looking for a value of solar
5 or a solar avoided cost, in Georgia, that's what we use the
6 renewable cost benefit framework for; right?

7 A From a conceptual standpoint, I suppose that's
8 the case.

9 Q And in Arizona, isn't it true that they
10 specifically identify cost shifting and a potential for
11 worsening cost shifts as the reason for the change in the
12 net metering policy?

13 A That was certainly one consideration.

14 Q And in South Carolina, the general assembly
15 passed a law instructing the Commission to eliminate any
16 cost shift to the greatest extent practicable; right?

17 A It did. And you know what happened there? We
18 still have net metering in South Carolina among the Duke
19 utilities, and we have unchanged net metering in South
20 Carolina for SCE&G, Dominion South Carolina.

21 Q And several other states have changed their net
22 metering policies so that exported energy is credited
23 avoided cost; right? Those were, I think, Kansas, Kentucky,
24 Louisiana, and North Carolina from your list of 17?

25 A Not North Carolina.

1 Q Are you sure?

2 A North Carolina hasn't moved to a net metering
3 successor tariff.

4 Q No. They -- their exported energy is to be
5 credited avoided cost was my question.

6 A That's not net metering.

7 Q That's -- yeah, but that wasn't my question.
8 My question was that they have passed -- they have passed
9 rules that require exported energy to be valued at avoided
10 cost?

11 A North Carolina has not done that.

12 Q Okay. Well, there are -- there are other
13 states that have -- have provided for avoided cost plus.
14 Right? Such as Michigan, Mississippi, and Utah, but it's
15 below the retail?

16 A Yeah. You said Michigan, Mississippi, and
17 Utah. That's -- that's right. Yeah. It's kind of in
18 between them.

19 Q Indiana, I think, also.

20 A Right.

21 Q And it's between avoided cost and full retail?

22 A All four of those examples, yeah, that's the
23 case.

24 COMMISSIONER MCDONALD: Does this mean by
25 comparing states by states by states that it becomes

1 a policy decision for a commission? Is that -- is
2 that what I'm reading out of the back and forth?

3 MR. HEWITSON: That is certainly something that
4 you can read out of this, Commissioner McDonald.

5 MR. BARNES: I mean, yeah, there are -- there
6 are elements of cost-of-service evaluation, you know,
7 studies I think that the company hasn't done that I
8 think would be very valuable for informing the
9 Commission's decision.

10 Ultimately, there is -- on a lot of levels, it
11 is at some level a policy decision.

12 MADAM CHAIR PRIDEMORE: It does appear that
13 North Carolina does pay back net metering at avoided
14 cost per House Bill 589 passed this year.

15 MR. BARNES: I am familiar with House Bill 589.
16 Nothing has changed in North Carolina since House
17 Bill 589 was enacted. It still offers retail
18 roll-over. The Duke solar choice proposals that are
19 proceeding through the North Carolina Commission at
20 the present time do not transition to avoided costs
21 for exports. It's kind of a -- it's a somewhat
22 different methodology that retains an element of net
23 metering.

24 So whatever -- I don't have HB 589 right in
25 front of me.

1 BY MR. HEWITSON:

2 Q I do. Do you want a copy?

3 A Sure.

4 MR. HEWITSON: Well, if the Chair wants to
5 explore this.

6 MADAM CHAIR PRIDEMORE: Certainly, but I'm
7 reading it right now on Southern Energy.com, which is
8 the description. I mean, I can text the commissioner
9 from North Carolina as well. But, I mean, I've had
10 conversations with them. I know it's at avoided
11 cost.

12 MR. BARNES: That's -- I think -- I think we
13 might be kind of like two trains passing each other
14 in the night. Where the way solar choice is being
15 proposed is not as a compensation of exports at
16 avoided costs. And this is directly pursuant to
17 HB 589, so however that -- however HB 589 is being
18 interpreted, at least by Duke in its proposal, is
19 not -- is not reflective of just avoided costs for
20 exports.

21 The solar choice tariff is not avoided costs
22 for exports. That's not exactly what it -- how it
23 works.

24 MR. HEWITSON: Okay. Let me go ahead and --

25 MADAM CHAIR PRIDEMORE: I don't know what to

1 say. It is. We can be two trains. We can be in the
2 day or the night, but it is. They -- they pay back
3 the export at avoided cost, that the Commission sets
4 in an avoided cost docket, the same way that Georgia
5 sets ours.

6 MR. BARNES: They pay monthly exports at
7 avoided costs under solar choice. That's not avoided
8 costs for all exports. You know, I would be happy to
9 kind of provide the specifics of Duke Energy's solar
10 choice proposal in North Carolina pursuant to HB 589,
11 which is basically the same thing that has been
12 adopted in South Carolina, which retains net
13 metering.

14 If -- you know, if it will be valuable, you
15 know, that's -- that's an easy thing to offer.

16 MADAM CHAIR PRIDEMORE: Sure. Certainly. I'm
17 not trying to debate this with you. I'm just -- I'm
18 just trying to clear for the record that there is an
19 inaccuracy in the statement that is obvious.

20 MR. BARNES: Well, I think it's -- maybe -- you
21 know, it's a matter of how that language is being
22 interpreted and effectuated. So all I can say is the
23 Duke proposal is not exports at avoided costs. It's
24 something substantially different than that.

25 MR. HEWITSON: Let me move on, because we

1 haven't --

2 MADAM CHAIR PRIDEMORE: Please. Please move
3 on.

4 MR. HEWITSON: We haven't mentioned California
5 yet, so let me at least do that real quick.

6 MADAM CHAIR PRIDEMORE: The day is young.

7 BY MR. HEWITSON:

8 Q In California, the proposed successor rate,
9 NEM-3.0, will credit excess generation at avoided cost and,
10 I believe, will vary hourly under a TOU basis; right? Is
11 that your understanding?

12 A Yeah. Well, it's -- it's a little more
13 complicated than that, but basically, it's avoided
14 costs-plus initially. So it's the avoided costs according
15 to the CPC's avoided cost calculator, plus, call it, kind of
16 like a transition amount that applies for -- during the
17 first five years of the transition. Eventually reaching
18 ACC.

19 Q Right. And I assume you have read the proposed
20 order from the ALJ for the CPUC; right?

21 A I have.

22 Q And the decision specifically finds that the
23 current net metering computation policy negatively impacts
24 nonparticipating ratepayers, disproportionately harms
25 low-income ratepayers, and is not cost-effective. Right?

1 Is that what the order says? In part. It's a 200-page
2 order I understand.

3 A Yeah. One of the findings is that there is a
4 cost shift, and that, you know, comparatively speaking, it
5 is adversely affecting low-income ratepayers.

6 Q Okay. And in a lot of these states that we've
7 been talking about, is it your understanding that solar
8 lobbyists and special interest groups opposed the measures
9 to withdraw or to change the net metering policies?

10 A I mean, that would typically be the case. I
11 mean, I've certainly been a part of a few of those.

12 Q Okay. And one of the arguments they make,
13 similar to your testimony on page 31, lines 1 through 16, is
14 that behind-the-meter customers have invested substantial
15 money in their systems and should not have to put those
16 investments in jeopardy. Is that right?

17 A I mean, that's my -- that's my argument that
18 there should legacy rights established for -- for those
19 customers.

20 Q Okay. And as those states retreat from monthly
21 net metering, you advocate that this Commission
22 significantly increase monthly net metering in Georgia;
23 right?

24 A To a point where it would be reasonable to kind
25 of establish a transition. And, you know, there are a

1 couple of reasons for that. One, we apparently don't have
2 the information necessary to actually determine what, if
3 any, cost shift actually exists. And a bit of a runway,
4 say, an expansion of the program that allows Georgia Power
5 time to collect information and data on customer usage
6 characteristics that actually allow us to really evaluate
7 the question of cost shifting and inform a decision would be
8 very useful.

9 Now, we're not going to get that if the company
10 gets its way and we basically don't have any more DG on the
11 system.

12 So -- you know, part of this, you know -- part
13 of the -- part of the idea here is that, apparently, the
14 company currently doesn't have the information that's needed
15 to really evaluate this question. So we have the luxury,
16 given that any issue that might be present is awfully small
17 right now, to take the time, allow some customers to benefit
18 in the interim, and to then fully study the nature and
19 magnitude of the problem, and, based on that, determine a
20 reasonable solution or a transition or, you know, whatever
21 the case may be based on the results of that analysis, at a
22 time further down the road when, you know, it still won't be
23 a problem. It will be a problem of small magnitude.

24 Q So as I understand what you just said,
25 basically what you're advocating for is, it's a small

1 problem now. We should increase it to see how big the
2 problem gets, and then -- and then solve the problem?

3 A I'm not -- I'm not acknowledging that it is a
4 problem now, because we haven't conducted the -- we haven't
5 conducted the analysis, and the company hasn't been able to.

6 Q It's not reasonably your testimony -- or is it?
7 You tell me -- that all these other states have identified a
8 cost shift with net metering, and somehow some way, Georgia
9 will be different and there won't be a cost shift with
10 monthly net metering?

11 A You know, it's certainly possible, and I'll
12 tell you why. The reason we do these studies -- now, I
13 participated in the South Carolina net metering proceedings.
14 In the case of Dominion South Carolina, they essentially
15 kind of performed an analysis very similar to what the
16 company has performed where they looked at lost revenue.

17 When I actually evaluated the company's cost of
18 service and applied the values of -- that solar provides for
19 reduction in coincident peaks at the transmission,
20 generation, and distribution level, as it turns out, there
21 was no cost shift at all.

22 Other residential customers were benefiting, or
23 at most, impacted in a de minimis way by having solar
24 customers within their class because they were allocated
25 lower costs due to the fact that these solar customers were

1 reducing the allocators for things like production demand
2 and transmission demand. So there was no cost shift.
3 That's exactly why we have to do these analyses. You can't
4 just kind of throw something together. You have to do the
5 homework.

6 Q And the analysis that provides a lot of that
7 information is contained in the renewable cost benefit
8 framework, but you said you're not familiar with that;
9 right?

10 A The renewable cost benefit framework is a
11 marginal cost analysis, at least as I understand kind of the
12 way we typically look at avoided cost.

13 What I'm talking about was the analysis I
14 conducted of Dominion South Carolina's embedded cost study
15 and all of the allocators that are used to determine what
16 classes bear what responsibility.

17 That -- the zero cost shift that I did, that I
18 discovered, was based on that embedded cost study.

19 Q And the embedded cost of Georgia Power that
20 we're talking about now that set the revenue requirements
21 isn't going to change going forward by adding more monthly
22 netting. The overall embedded cost doesn't change just
23 because you allow more monthly netting customers, does it?

24 A Well, you should be kind of considering both
25 the near-term effects -- near-term effects, based on

1 embedded costs, like, are customers actually paying more
2 right now, as well as will they be paying more later based
3 on marginal costs. So marginal costs and embedded costs are
4 also kind of -- they're both important aspects to conducting
5 that kind of evaluation.

6 Q Yes.

7 A We don't have either here, really.

8 Q No. I understand you want to look at the
9 future, but what I'm saying is right now the revenue
10 requirements that are being set by this Commission for the
11 rate case will not change if, over the next three years,
12 there are 5,000 more net metering customers or any other
13 number. Will they?

14 A Not to any significant degree, I would not
15 think.

16 Q Not to any degree?

17 A Well, you can avoid, I don't know, transformer
18 replacements, things like that that, you know, in the near
19 term. There could be some -- I'm saying there could be some
20 level of avoided costs. I can't quantify it, but...

21 Q It wouldn't -- it wouldn't change in any way,
22 shape, or form the cost allocation to residential customers,
23 a transformer here and there, would it?

24 A Well, it would change the -- if the company
25 incorporated how solar reduces, you know, the 12 CP into its

1 cost-of-service study, it would reduce costs allocated to,
2 say, residential customers.

3 Q You're talking about allocations. What I said
4 is, the overall revenue requirements for the system to run
5 and operate the system that the company has identified are
6 not going to change by moving customers to monthly netting?

7 A Well, I said it wouldn't be a -- wait. Moving
8 customers -- wait. Are you saying that you move customers
9 to monthly netting, and, therefore, there are more netting
10 customers on the system?

11 Q Yes. Yes. I'm sorry. Yeah. Increasing the
12 number of monthly netting customers.

13 A Plausibly there could be some level of cost
14 savings. I don't know what it is. That's -- that was kind
15 of -- I said it wouldn't be meaningful, but there could be
16 some.

17 Q All right. Thank you, Mr. Barnes. That's all
18 I have for you.

19 MADAM CHAIR PRIDEMORE: Redirect?

20 REDIRECT EXAMINATION

21 BY MS. WHITFIELD:

22 Q Well, fortunately or unfortunately, Ms. Kysor
23 who was in the weeds on this is not here, so I will stay
24 very high level with you, Mr. Barnes, in my redirect.

25 Mr. Hewitson asked you about whether the only

1 difference between instantaneous netting and monthly netting
2 was that Georgia Power collects less revenue.

3 Do you remember that?

4 A I do.

5 Q And what was your response to that?

6 A That there was also, you know, there's an
7 impact on customers that, you know, effectively kind of
8 arises from the fact that the company is collecting more or
9 less revenue.

10 Q And he spent a lot of time talking about
11 revenue in the same breath as cost shift. Could you take
12 this opportunity to explain how revenue erosion and cost
13 shift are two different concepts and why it matters a lot?

14 A Sure. So first off, like I was talking about,
15 in today's current rates, today's current rates aren't
16 affected by the fact that there are, you know, 32 megawatts
17 of residential RNR customers on them, because, you know,
18 rates haven't been adjusted to reflect any changes in the
19 company's system since, you know, 2019. So right now,
20 there's -- there's no cost shift.

21 The company's rates proposal is not, you
22 know -- its general rate proposal, apart from the revenue
23 erosion adjustment it's proposing, is not attributing, you
24 know, say, a higher rate of increase in residential class
25 rates as a result of, you know, these 32 megawatts of

1 primarily residential DG customers.

2 You know, it's not saying that the residential
3 class is significantly below parity because of DG, and,
4 therefore, we have to raise their rates to a higher amount.
5 You know, they are proposing an across-the-board increase
6 that's not shifting costs one way or another relative to,
7 you know, kind of what they already are.

8 The only -- the cost shift that is other
9 nonparticipant customers paying for DG customers, that only
10 arises due to the company's proposal to recover this
11 additional \$1.4 million in revenue erosion.

12 Now, the way they allocate that among customer
13 classes, you know, is that -- is that correct? Is that the
14 correct way to kind of reflect, even if one acknowledges --
15 even if one says that that's a cost shift, is that the right
16 way to do it? Well, I don't know because the company hasn't
17 conducted kind of like a fully distributed cost-of-service
18 study to say, well, this is the cost to serve DG customers
19 before DG. This is the cost afterwards. This is the
20 difference. This is what they pay before. This is what
21 they pay after. And kind of intelligently, you know,
22 determine where the money needs to be, kind of moved back
23 and forth.

24 Q Mr. Barnes, could you explain what kind of
25 information was missing from the company's response that

1 might have been helpful in doing a full cost-of-service
2 evaluation?

3 MR. HEWITSON: Madam Chair, that wasn't a
4 question of mine on cross. I don't think that's a
5 matter for redirect.

6 MADAM CHAIR PRIDEMORE: It was not. Sustained.

7 MS. WHITFIELD: Madam Chair, he spoke
8 extensively about the cost shift.

9 MADAM CHAIR PRIDEMORE: Sustained,
10 Ms. Whitfield.

11 MS. WHITFIELD: Understood.

12 BY MS. WHITFIELD:

13 Q Mr. Barnes, Mr. Hewitson asked you about a lot
14 of other states. Is there anything you would like to share
15 with the Commission about the amount of solar penetration in
16 those other states compared to Georgia?

17 A Well, sure. I mean, you know, if we think
18 about the RNR cap as it is right now -- or, sorry, the
19 monthly netting cap as it is right now, you know, it's -- I
20 think it's equivalent to, like, .2 percent of peak load,
21 which is about the lowest in the country.

22 You know, those states that -- that were
23 referenced as kind of transitioning away from net metering,
24 you know, certainly none of them that I can recall did any
25 transition before reaching 1 percent. That's even, you

1 know, states like -- you know, states like an Indiana or a
2 Kentucky, they were still basically kind of like at the
3 1 percent level by the time they transitioned.

4 Most of those states that have actively kind of
5 had these extensive proceedings and ultimately adopted a
6 successor have, you know, penetration levels, I mean, you're
7 talking in Hawaii, like, 50 percent on one island. You
8 know, California, I would imagine it's -- you know, it's
9 certainly well in excess of 10 percent and probably closer
10 to 20 percent.

11 You know, so, I mean, where Georgia stands
12 right now relative to those benchmarks is on kind of the
13 very, very low end. And, you know, my recommended 3 percent
14 cap on monthly netting under an extended program, is kind
15 reflective of the low end of where states have kind of
16 historically decided to make decisions on successors.

17 Q Would you agree --

18 MADAM CHAIR PRIDEMORE: Mr. Barnes, I'm going
19 to stop you right there. You didn't answer her
20 question. Her question was very specific, and it
21 asked how Georgia ranks in solar energy adoption
22 compared to other states. Not about monthly netting
23 or rooftop solar. Solar.

24 Where is Georgia in relation to other states in
25 the nation when it comes to solar rankings?

1 MR. BARNES: I don't know the specific answer
2 to -- like, from a rooftop standpoint or like --
3 MADAM CHAIR PRIDEMORE: She asked you solar.
4 She didn't -- she didn't get specific.
5 MS. WHITFIELD: Well, Madam Chair, if it
6 helps --
7 MADAM CHAIR PRIDEMORE: She asked you solar,
8 so --
9 MS. WHITFIELD: My intention was to ask about
10 rooftop, but if the Chair would prefer to talk about
11 solar generally, we could --
12 MADAM CHAIR PRIDEMORE: Your question was about
13 solar, Ms. Whitfield, and just --
14 MS. WHITFIELD: I know. I'd like to clarify
15 just to make everyone more focused on the issue at
16 hand.
17 MADAM CHAIR PRIDEMORE: Okay. Well, the issue
18 that I have at hand is solar, and if you don't know
19 where Georgia ranks, I think that probably
20 Commissioner McDonald would love to tell you, because
21 he started the program. So we are at -- we were
22 nine, we're at seven, and now it's been, when
23 everything is fully subscribed, we'll be number four
24 in the country in solar. So, yeah.
25 MR. BARNES: I accept that. You know, my -- I

1 interpreted that as, like, framing a comparison
2 between, like, behind-the-meter solar and the caps
3 that states have placed on that.

4 MADAM CHAIR PRIDEMORE: Okay.

5 MR. BARNES: I didn't mean to speak to, you
6 know, overall, like, utility scale, all that stuff.

7 MADAM CHAIR PRIDEMORE: All right. Obviously,
8 you answered about rooftop, but the question was
9 about solar. And we're number four in the country.
10 So I just wanted you to know that.

11 MS. WHITFIELD: And that was my intention as
12 well with respect to the question. Which -- is there
13 any clarification further that you think is helpful,
14 Madam Chair?

15 MADAM CHAIR PRIDEMORE: No. Thank you. Go
16 ahead.

17 MS. WHITFIELD: Okay. That is all I have for
18 now. But I would like the opportunity to supplement
19 the record with respect to Mr. Barnes's testimony on
20 the North Carolina bill in light of the fact that he
21 was characterized as being inaccurate, and I'm not
22 sure that that was, in fact, the testimony on the
23 record here today.

24 So I would like the opportunity for us to have
25 an opportunity to clarify that by supplementing the

1 record in some way.

2 MADAM CHAIR PRIDEMORE: Mr. Hewitson, you have
3 a comment?

4 MR. HEWITSON: I think that would be a
5 wonderful thing for their brief, but in Georgia the
6 proceedings and the record usually close right after
7 the rebuttal hearing ends. So if they want to brief
8 it, I think everyone could brief it, and I think that
9 would be the proper avenue.

10 MS. WHITFIELD: They usually do close, but also
11 I think it's a little atypical for an expert witness
12 to be told he's inaccurate on the stand and not be
13 given an opportunity to clarify that.

14 MR. HEWITSON: And there's nothing --

15 MADAM CHAIR PRIDEMORE: Considering he was told
16 that he was inaccurate by the Chair, and it's at the
17 Chair's discretion, I say put it in your brief or --
18 but we go into ex parte at the conclusion of this
19 hearing. So this is it. This is the end. So...

20 MS. WHITFIELD: Denied?

21 MADAM CHAIR PRIDEMORE: Denied, yeah. Put it
22 in the brief. But use the proper -- there's a proper
23 way for you to be able to address the Commission.
24 I'm just asking you to use the appropriate legal
25 channel.

1 MS. WHITFIELD: The procedures.

2 MADAM CHAIR PRIDEMORE: Thank you.

3 MS. WHITFIELD: Yes, Chair.

4 I would request that GIPL Exhibits 11 and 12 be

5 admitted into evidence, and that Mr. Barnes be

6 excused.

7 MADAM CHAIR PRIDEMORE: So moved, and you're

8 excused, Mr. Barnes.

9 (GIPL Exhibits 11 and 12 were admitted into

10 evidence.)

11 MS. WHITFIELD: Thank you.

12 MR. BARNES: Thank you.

13 MADAM CHAIR PRIDEMORE: GA Solar, please go

14 ahead with your witness. I just want to remind

15 witnesses, you are under oath.

16 All right. Go ahead, Mr. Moreland.

17 MR MORELAND: Georgia Solar calls Kenneth Sercy

18 to the stand.

19 Mr. Sercy, could you please raise your right

20 hand.

21 Thereupon,

22 KENNETH SERCY,

23 having been duly sworn, testified as follows:

24 DIRECT EXAMINATION

25 //

1 BY MR. MORELAND:

2 Q Please state your name, employer, and business
3 address.

4 A Kenneth Sercy of Greenlink Analytics, Inc., 252
5 Carlisle Park Drive Northeast, Atlanta, Georgia.

6 Q Are you here today testifying on behalf of
7 Georgia Solar?

8 A Yes, I am.

9 Q On November 18th, did you file or cause to be
10 filed 41 pages of written direct testimony for this
11 proceeding in a question-and-answer format along with two
12 exhibits?

13 A Yes, I did.

14 Q Do you have any corrections to that testimony?

15 A No, I do not.

16 Q If I were to ask you the same questions today
17 as filed in your prefiled testimony, would your answers be
18 the same?

19 A Yes, they would.

20 MR. MORELAND: Madam Chair, we move to have the
21 witness's prefiled testimony be copied into the
22 record as read orally today.

23 MADAM CHAIR PRIDEMORE: Mr. Moreland, I have to
24 ask you a question. Let me stop you right there.
25 There's a discrepancy in here.

1 Are you an attorney?

2 MR. MORELAND: I am an attorney, yes.

3 MADAM CHAIR PRIDEMORE: You are? Okay. All

4 right.

5 MR. MORELAND: However, I have not -- I don't

6 practice a lot, and so my CLE classes have lapsed.

7 I'm an attorney, but I am not licensed to practice

8 law until I get my CLE classes up to date.

9 MADAM CHAIR PRIDEMORE: Okay. So for -- for

10 the point of caution, legally, let's have one of the

11 attorneys in the room swear your witness in. Okay?

12 MR. MORELAND: Okay. That's fine.

13 MADAM CHAIR PRIDEMORE: All right. Anybody

14 who's willing to swear in Mr. Moreland's witness?

15 MR. HEWITSON: I don't think it would be proper

16 for us to swear him in.

17 MADAM CHAIR PRIDEMORE: It would not. It would

18 not. Mr. Thomasson maybe? Or Mr. Thomas?

19 Thank you.

20 MR. THOMAS: Can you please raise your right

21 hand.

22 Thereupon,

23 KENNETH SERCY,

24 having been duly sworn, testified as follows:

25 MADAM CHAIR PRIDEMORE: Thank you, Mr. Thomas.

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Thank you, Mr. Sercy. Legal proceeding.

Okay. Go ahead, Mr. Moreland. Your testimony
is marked in the record and so moved.

(Whereupon, the prefiled testimony of Kenneth
of Kenneth Sercy follows:)

STATE OF GEORGIA

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY OF
KENNETH SERCY

Presented on behalf
of the Georgia Solar Energy Association, ("GA Solar")

November 18, 2022

I. INTRODUCTION

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

A: My name is Kenneth Sercy. I am an Energy Analyst at Greenlink Analytics, Inc, a scientific energy research non-profit organization located at 252 Carlyle Park Drive NE, Atlanta, GA 30307.

Q: PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A: I have a Bachelor of Science degree from Clemson University and a Master of Environmental Management degree from Duke University, and ten years of experience in electricity markets, policy, and regulation focused on engineering-economic modeling and cost-of-service ratemaking. I have designed, run, and evaluated a variety of electric power modeling analyses including production cost, capacity expansion, and avoided cost and related cost-effectiveness tests, and have evaluated cost recovery, resource planning, asset certification, program and tariff design in more than sixty regulated utility proceedings, primarily in South Carolina. My professional experience also includes modeling renewable energy project economics and supporting state-level distributed energy resource policy and regulatory efforts.

While studying at Duke University, I worked for two years at the Nicholas Institute for Environmental Policy Solutions supporting energy modeling research using the US Department of Energy's National Energy Modeling System. After graduating from Duke in 2012, I served as the South Carolina Coastal Conservation League's Utility Regulation Specialist for five years, where I managed the organization's work before the South Carolina Public Service Commission and supported a variety of electric sector policy objectives. From 2018 to 2021, I worked as an independent clean energy consultant providing expert witness testimony, regulatory analysis and guidance, energy modeling

1 services, and market research relating to renewable energy and energy storage
2 development, in both traditionally regulated and competitive wholesale regions of the
3 United States. I joined Greenlink Analytics in 2022 where I work across teams to provide
4 quantitative analyses, research, and decision-making support at the city, state, and
5 institutional level. I have co-authored technical papers published by Clemson
6 University's Strom Thurmond Institute, the North Carolina Sustainable Energy
7 Association, and the journal *Energy Policy*. A copy of my curriculum vitae is included as
8 Exhibit 1 to my testimony.

9 Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE
10 COMMISSION?

11 A: No, I have not.

12 Q: ON WHOSE BEHALF ARE YOU TESTIFYING?

13 A: I am testifying on behalf of the Georgia Solar Energy Association, known locally as
14 Georgia Solar. Georgia Solar is a 501(c)(3) organization and the oldest solar education
15 and advocacy organization in the State of Georgia.

16 Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

17 A: The purpose of my testimony is to provide analysis and recommendations relating to
18 the structure and pricing of the RNR-10 tariff and its customer impact, in order to
19 contribute to the considerations raised in the 2022 Georgia Power Company ("GPC")
20 Integrated Resource Plan order.¹

¹ Georgia Public Service Commission Docket Nos. 44160 and 44161, Order Adopting Stipulation at 44.

1 Q: PLEASE SUMMARIZE YOUR CONCLUSIONS.

2 A: Net metering is a proven rate design approach for enabling customer-sited solar PV. A
3 modest increase in monthly netting participation across GPC territory would have
4 widespread benefits, including creation of 2,400 jobs and \$75 million in annual bill
5 savings, as well as enhanced customer choice, a variety of system-wide benefits, and a
6 maturing local rooftop solar market with further reduced PV prices. All GPC customers
7 would benefit, with increasing distributed generation participation providing a range of
8 direct and indirect benefits to customers.

9 Expanding net metering would promote equity across Georgia as well. Low- and
10 moderate-income (LMI) and disadvantaged communities have been adopters of rooftop
11 solar nationally and in Georgia. And with intentional programming, additional shares of
12 the benefits of an expanded monthly netting program could flow into these
13 communities and provide a much-needed financial boost. A dedicated working group
14 could coordinate financial support from sources such as IRA programs and LIHEAP,
15 ensure streamlined program administration, provide for workforce training, and help to
16 educate and enroll customers, all as part of a place-based approach. This working group
17 could also develop a rooftop PV consumer protections framework.

18 Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

19 A: I'm making three recommendations. First, I recommend that the customer and capacity
20 limits on the RNR tariff's monthly netting provisions be lifted. Second, I recommend that
21 GPC's request to force rooftop solar PV adopters onto a 3-part rate be rejected and that
22 customers adopting rooftop solar continue to be permitted to choose their own service
23 tariff. And third, I recommend that a rooftop solar working group be formed to
24 coordinate efforts to ensure that all customers, including those in LMI communities,
25 benefit from the market growth under an expanded monthly netting program, and I

1 recommend that the same or similar working group be tasked with collaboratively
2 developing reasonable rooftop PV consumer protections.

3
4 **II. NET METERING BENEFITS**
5

6 Q: WHAT IS NET METERING?

7 A: Net metering is a policy that allows energy produced behind the customer's meter and
8 exported onto the grid to offset the customer's energy consumption for billing
9 purposes, thus crediting the customer's energy production at the retail rate.

10 Q: WHY IS NET METERING IMPORTANT?

11 A: Net metering is the most widely used approach across the United States for enabling
12 customers to choose to meet a portion of their electricity consumption with on-site
13 solar photovoltaic renewable energy.² It has been a foundational policy that has led to
14 job creation, customer bill savings, and energy resource diversification in dozens of
15 states.³ Based on the wide gap between the amount of net metered capacity and the
16 amount of distributed PV capacity under compensation approaches other than net
17 metering, no other compensation approach comes close to net metering in terms of
18 proven success at enabling customer-sited renewable energy.

² The most recent US Energy Information Administration Form 861 data, from 2021, shows 31.4 GW of net metered PV capacity and only 2.4 GW of non-net metered distributed PV capacity in the United States.

³ NREL's Net Metering Basics webpage (<https://www.nrel.gov/state-local-tribal/basics-net-metering.html>, accessed 11/15/22) notes that 41 states, plus Washington, D.C., American Samoa, U.S. Virgin Islands, and Puerto Rico, have mandatory net metering policies, while some utilities in additional states such as Texas and Idaho voluntarily offer net metering arrangements to customers. Further, NREL states that "Net metering has been consistently recognized as a foundational policy to support the growth of a distributed solar marketplace."

1 The US National Renewable Energy Laboratory ("NREL") summarizes several advantages
2 of net metering⁴ that have driven this success:

- 3 • Straightforward billing concept for customers and utilities
- 4 • Customer compensation for excess generation improves their financial
5 return
- 6 • Can be implemented with existing retail rates and often with existing
7 metering infrastructure

8 Q: HAS GEORGIA SEEN BENEFITS FROM NET METERING?

9 A: Yes. The existing GPC "monthly netting" program available to up to 5,000 customers has
10 driven installation of approximately 36.79 MW of customer-sited solar PV.⁵ This rooftop
11 solar market activity has provided electric bill savings to thousands of GPC customers,
12 helped drive local economic growth, and diversified the state's power grid.

13 It's also worth noting that more rooftop solar was installed in GPC territory since the
14 monthly netting pilot began than in multiple decades before the pilot. Based on the data
15 reported to the US Energy Information Administration ("EIA"), GPC had 5.4 MW of
16 residential solar PV through 2019, which had grown to 21.5 MW of residential solar PV
17 by 2021.⁶

18 Even with the market growth under the monthly netting pilot, Georgia has among the
19 lowest shares of rooftop solar in the country, including substantially trailing other
20 Southeastern states like Florida, Louisiana, South Carolina, Virginia, North Carolina, and
21 Arkansas. This is shown below in Table 1.

⁴ Id.

⁵ <https://www.georgiapower.com/company/energy-industry/energy-sources/solar-energy/solar/solar-buy-back.html>, accessed 11/7/22.

⁶ US Energy Information Administration Form 861, data for 2019 and 2021.

1

Table 1: Distributed Generation Relative to Customer Base by State⁷, 2021

⁷ Source: EIA 861, 2021 data. "NM" represents net-metered PV installations; "DG" represents the sum of net metered PV installations and all non-net-metered distributed generation (Form 861 does not provide installation counts by technology).

	DG as % of customer	NM as % of customer
HI	19.4%	18.1%
CA	7.0%	7.0%
NJ	6.8%	3.2%
AZ	6.7%	6.7%
NV	5.6%	5.6%
UT	4.3%	4.3%
NM	3.8%	3.8%
CO	3.8%	3.8%
VT	3.3%	2.5%
CT	3.3%	3.2%
DC	2.9%	2.9%
MD	2.7%	2.7%
MA	2.5%	2.5%
RI	2.2%	1.3%
DE	1.7%	1.7%
NY	1.7%	1.7%
OR	1.4%	1.3%
TX	1.4%	0.6%
NH	1.4%	1.4%
ID	1.2%	1.2%
FL	1.2%	1.2%
LA	1.2%	1.2%
SC	1.0%	1.0%
WA	0.9%	0.9%
ME	0.8%	0.8%
VA	0.6%	0.6%
MO	0.6%	0.6%
IA	0.6%	0.6%
AK	0.6%	0.6%
MT	0.6%	0.6%
NC	0.6%	0.5%
PA	0.5%	0.5%
IL	0.5%	0.4%
WY	0.5%	0.5%
AR	0.4%	0.4%
MN	0.4%	0.4%
WI	0.3%	0.3%
MI	0.3%	0.3%
IN	0.2%	0.2%
KS	0.2%	0.2%
OK	0.2%	0.2%
KY	0.2%	0.2%
OH	0.2%	0.2%
WV	0.2%	0.2%
GA	0.1%	0.1%
NE	0.1%	0.1%
SD	0.1%	0.0%
TN	0.1%	0.0%
MS	0.1%	0.1%
AL	0.0%	0.0%
ND	0.0%	0.0%

1 Q: HAVE YOU QUANTIFIED ANY POTENTIAL BENEFITS GEORGIA COULD EXPERIENCE IF THE
2 MONTHLY NETTING PROGRAM WERE EXPANDED?

3 A: Yes, I've analyzed the benefits of additional monthly netting in two areas: economic
4 development impacts and bill savings. While these analyses are not intended as
5 comprehensive benefits assessments, I also discuss several additional monthly netting
6 benefits in a qualitative manner.

7 In my quantitative analysis, I evaluated the impact of monthly netting at several
8 participation levels for illustrative purposes: 1%, 2%, and 3% of GPC's customer base.
9 These participation levels represent market growth that could be expected over the
10 next 3 to 5 years under an uncapped monthly netting program.

11 Q: PLEASE SHARE YOUR APPROACH AND FINDINGS ON ECONOMIC DEVELOPMENT
12 IMPACTS OF AN EXPANDED MONTHLY NETTING PROGRAM.

13 A: I used the IMPLAN macroeconomic model⁸ to estimate net job creation, gross state
14 product, and income impacts in Georgia at different retail monthly netting program
15 participation levels. IMPLAN is widely used to analyze the effects of changes in an area's
16 economy – for example, the construction and operation of a new factory. I deployed the
17 IMPLAN model to evaluate the impacts of investment in rooftop solar PV, along with the
18 associated bill savings impacts.

19 Table 2 shows direct, indirect, and induced economic impacts of a monthly netting
20 program reaching 80,000 residential GPC customers (3% of the Company's total
21 customer base). I assume an average PV system size of 6 kW, for a total capacity of 478
22 MW. Exhibit 2 shows the same figures for 1% and 2% participation levels.

⁸ www.implan.com

Table 2: Net Economic Development Impacts of 3% Monthly Netting

	Direct	Indirect	Induced	Total
Employment	1,477	386	559	2,422
Income (\$M)	286	66	93	445
GSP (\$M)	93	30	199	322

For context, the jobs growth figure at 3% participation amounts to approximately half of the workforce at Coca-Cola's Atlanta headquarters.⁹ These are important jobs and economic development considerations that have informed past Georgia Public Service Commission actions – for example, earlier this year the Commission approved a motion on a biomass RFP in recognition of "...the benefits of biomass as a renewable resource, and in order to support Georgia's forest industry and rural job and economic development growth..."¹⁰

Q: CAN YOU ELABORATE ON THE FINDINGS OF THE ECONOMIC DEVELOPMENT IMPACTS ANALYSIS?

A: Absolutely. First, I'll discuss the definitions of direct, indirect, and induced effects.

1. Direct effects are those occurring directly from the economic activity in question – in this case, rooftop solar PV installations. For example, direct employment effects would be the jobs created for technicians to install the PV systems onto customer rooftops as well as the management, administrative, and other jobs within the solar businesses that deliver rooftop solar to customers.
2. Indirect effects are supply chain impacts occurring from the direct effects. For example, solar businesses source products and services from a variety of other firms, some of which are Georgia businesses that then employ more workers to meet additional demand.

⁹ <https://www.coca-colacompany.com/au/news/explore-cutting-edge-coca-cola-offices-around-the-world>

¹⁰ Georgia Public Service Commission Docket Nos. 44160 and 44161, Order Adopting Stipulation at 43.

1 3. Induced effects are further ripple effects in the economy that stem from direct and
2 indirect effects. For example, induced employment effects occur because of the
3 income earned by workers employed due to direct and indirect effects, which the
4 workers then spend on a variety of local goods and services, such as housing, food,
5 and entertainment, thereby creating demand in those economic sectors that leads
6 to employment gains to meet the elevated demand.

7 Second, I'll describe the output metrics themselves. The employment data in Table 2
8 refer to full-time employees under an assumption that an average job lasts 4 years.
9 Income is the salary compensation received by the workers in the jobs created. And
10 gross state product is the value-add of the goods produced by the economic activity.

11 Third, I'd like to emphasize that this is a net economic impacts analysis, meaning that
12 the analysis accounts not only for positive economic development but also for any
13 economic losses that may occur. For example, I assume that reduced consumption of
14 utility power has a negative effect on jobs, income, and GSP from the electric utility
15 sector in Georgia, and the figures in Table 2 have netted out these losses.

16 Q: PLEASE SHARE YOUR APPROACH AND FINDINGS ON BILL SAVINGS IMPACTS OF AN
17 EXPANDED MONTHLY NETTING PROGRAM.

18 A: I modeled electric bill costs for a household consuming 1,000 kWh per month on the
19 current GPC R-25 tariff, along with a second case where the household adds a PV system
20 to offset approximately 50% of its grid consumption. Because households installing
21 rooftop solar vary in their before-solar electricity consumption and in the size of the PV
22 system installed, I also modeled a higher consumption household with a larger PV
23 system and confirmed that on a per-kWh basis the bill savings were virtually the same.

24 I extrapolated the bill savings calculated for the household described above across the
25 same program size assumed for the economic development analysis above; that is, 3%
26 of GPC customers. I estimate approximately \$75 million in annual bill savings from

1 monthly netting under the current residential rates, which equates to an average
2 household savings of \$937 over the course of a year. Exhibit 2 shows the bill savings
3 estimates for 1% and 2% participation levels.

4 While these bill savings benefit customers installing rooftop solar, the entire GPC system
5 benefits as well from reduced strain on the transmission and distribution grids,
6 increased fuel diversity, and lower environmental and public health impacts (and thus
7 lower utility regulatory risk) from the power system as more electricity is generated
8 from small, distributed renewable systems.¹¹

9 Q: HOW WOULD YOU EXPECT THESE ECONOMIC DEVELOPMENT AND BILL SAVINGS
10 BENEFITS TO BE DISTRIBUTED ACROSS GEORGIA?

11 A: That depends on how the program is designed and implemented. Generally, the
12 economic development and bill savings benefits I've estimated would flow to a wide
13 range of Georgians, in different parts of the state and at different income levels. A
14 Lawrence Berkeley National Laboratory report released this month on residential solar
15 adopter trends found that solar adopters are heterogeneous in income and
16 demographics, with solar adoption becoming more widespread over time and reaching
17 more low-income households.¹² In Georgia, 30% of recent residential solar adopters
18 were households below 300% of FPL, with about 15% below 200% FPL and about 8%
19 below 150% FPL.¹³ About 6% of Georgia solar adopters were in disadvantaged
20 communities, compared to 18% of all Georgia households being in disadvantaged

¹¹ Numerous studies have estimated system-wide grid, financial, and social benefits of rooftop solar PV. For examples see Hansen, Lacy & Glick. A Review OF Solar PV Benefit & Cost Studies, 2nd Edition (Rocky Mountain Institute, 2013). https://rmi.org/wp-content/uploads/2017/05/RMI_Document_Repository_Public-Reprts_eLab-DER-Benefit-Cost-Deck_2nd_Edition131015.pdf Many of the studies reviewed found rooftop PV benefits equal to or exceeding the local retail rate.

¹² Sydney Forrester, Galen Barbose, Eric O'Shaughnessy, Naïm Darghouth, and Cristina Crespo Montañés. Residential Solar-Adopter Income and Demographic Trends. LBNL (November 2022) at 5 and 42. https://eta-publications.lbl.gov/sites/default/files/solar-adopter_income_trends_nov_2022.pdf

¹³ Id at 19.

1 communities.¹⁴ As noted above, all customers experience benefits from rooftop solar
2 additions to the grid via the value of multiple system-wide factors such as deferred grid
3 investment and risk reduction.

4 However, intentionally designing an inclusive monthly netting program that reaches
5 larger numbers of low- and moderate-income customers would enhance the level of
6 program benefits accruing to those communities and further promote equity in Georgia.
7 This is discussed in more detail later in my testimony.

8 Q: BESIDES ECONOMIC DEVELOPMENT, BILL SAVINGS, AND THE SYSTEM-WIDE BENEFITS
9 YOU'VE NOTED, ARE THERE OTHER BENEFITS OF AN EXPANDED MONTHLY NETTING
10 PROGRAM?

11 A: Yes. An expanded monthly netting program enhances customer choice within GPC
12 territory. Additionally, the market growth that would be supported by greater access to
13 monthly netting would aid in the maturation of the local renewable energy market,
14 which would in turn yield industry learning and lower installed costs for customers.¹⁵

15 Q: WOULD YOU EXPECT TO SEE THESE BENEFITS WITHOUT AN EXPANDED MONTHLY
16 NETTING PROGRAM?

17 A: No. Alternative compensation approaches generally lose either the financial benefits or
18 the simplicity of net metering, or both. As a result, I would expect customer adoption
19 without monthly netting to be comparatively muted.

¹⁴ Id at 21.

¹⁵ Solar PV soft costs have been found to be lower for larger systems (economies of scale could be accessed via customer aggregation approaches like Solarize campaigns), as well as for systems installed by more experienced installers, and systems installed in more concentrated and more competitive markets. Eric O'Shaughnessy, Gregory F. Nemet, Jacquelyn Pless, Robert Margolis. Addressing the Soft Cost Challenge in U.S. Small-Scale Solar PV System Pricing. *Energy Policy* **134** (November 2019). <https://www.osti.gov/servlets/purl/1566058>

1 An NREL analysis of the impact of rate design alternatives on solar PV customer electric
2 bills found that both demand charges and increased fixed charges could result in
3 substantially higher bills than under the standard net metering approach, and also
4 described and illustrated the complexity of the demand charge from a customer
5 perspective.¹⁶

6 This aligns with the EIA Form 861 data that I cited previously, showing that across the
7 US, relatively little distributed PV has been installed outside of net metering programs.
8 It's also consistent with the GPC experience whereby residential rooftop solar expanded
9 considerably under monthly netting compared to pre-net metering installations.

10 Thus, given diminished financial benefits to solar adopters and muted market growth
11 without monthly netting in place, the benefits I've described – from economic
12 development to customer bill savings to system benefits and enhanced customer choice
13 – would be unlikely to materialize.

14 Q: PLEASE PROVIDE YOUR CONCLUSIONS RELATED TO NET METERING BENEFITS.

15 A: My conclusions on net metering benefits are as follows:

- 16 • Net metering is unique as a compensation approach in its proven track record of
17 success, both in Georgia and nationally
- 18 • A modest increase in residential rooftop solar under an expanded monthly
19 netting program, to 3% of GPC's customer base, would add approximately 2,400
20 jobs and save \$75 million on participating customer bills, while also providing
21 additional grid benefits, enhancing customer choice, and driving rooftop solar
22 prices down

¹⁶ Lori Bird, Carolyn Davidson, Joyce McLaren, and John Miller. Impact of Rate Design Alternatives on Residential Solar Customer Bills: Increased Fixed Charges, Minimum Bills and Demand-Based Rates (NREL, September 2015).

- A diverse cross-section of Georgians would be expected to adopt rooftop solar PV with expanded monthly netting, including low- and moderate-income customers and households in disadvantaged communities, and
- This array of benefits is unlikely to materialize without monthly netting in place.

III. LOW- AND MODERATE-INCOME COMMUNITY BENEFITS

Q: HAS THE GEORGIA PUBLIC SERVICE COMMISSION TAKEN ACTIONS TO PRIORITIZE LOW- AND MODERATE-INCOME COMMUNITIES?

A: Yes. For example, this year the Commission approved significant funding for demand-side management programs designed to reach low- and moderate-income customers. The HopeWorks Program is aimed at "senior income qualified customers who have been underserved by previous DSM offerings."¹⁷ The Commission extended the Residential Investment to Save Energy pilot, which is "designed to serve income qualified customers that could not otherwise participate in DSM programs..."¹⁸ The Commission also approved a new Manufactured Homes Program "to serve homes that historically have been underserved by the Company's current DSM programs" and found that "customers living in manufactured homes often have significant energy burdens and thereby could greatly benefit from energy efficiency upgrades..."¹⁹

Further, the Commission approved an Income-Qualified Community Solar pilot.²⁰ GPC proposed the program in alignment with its "commitment to the communities it serves and recognizing barriers that may prevent income-qualified customers from accessing renewable energy..." The pilot will offer community solar subscriptions at discounted

¹⁷ Georgia Public Service Commission Docket Nos. 44160 and 44161, Order Adopting Stipulation at 37.

¹⁸ Id at 38.

¹⁹ Id at 39.

²⁰ Id at 27.

1 prices and will be marketed "through established relationships with community
2 partners, including housing authorities and customer education and awareness
3 organizations."²¹

4 These efforts to reach LMI communities are in line with actions by peer utilities
5 authorized by regulators across the Southeast. For example, the Mississippi Public
6 Service Commission recently approved a net metering program that provides additional
7 compensation to income-qualified customers for exported energy and also offers a
8 \$3,000 rebate to LMI customers to help defray upfront solar PV installation costs.²² A
9 recent review by the Southeast Energy Efficiency Alliance found 28 ratepayer-funded
10 low-income programs in 8 Southeastern states, and noted that "southeastern utilities
11 and policy makers have moved to address the dual issues of poverty and energy burden.
12 This has been reflected in both the volume of policy directives surrounding this issue
13 and the significant expansion of low-income energy efficiency programs."²³

14 Q: HOW WOULD AN INCLUSIVE EXPANDED MONTHLY NETTING PROGRAM REACHING LMI
15 COMMUNITIES MESH WITH THESE ACTIONS?

16 A: An expanded monthly netting program designed to reach LMI communities would
17 further build on past Georgia Public Service Commission actions to support LMI
18 customers as the cost of energy continues to rise. In other words, net metering is one
19 tool among many that can provide targeted benefits to communities that need them
20 most. Giving customers a variety of options for bill relief helps ensure that customers
21 with different needs and in different circumstances have access to programs that work

²¹ Georgia Power Company 2022 Integrated Resource Plan at 14-112 and 14-113.

²² Mississippi Public Service Commission Docket No. 2021-AD-19, Final Order Amending Rules (July 12, 2022; https://www.psc.state.ms.us/InSiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=671390) and Order Amending Rules Post-Rehearing (October 4, 2022; https://www.psc.state.ms.us/InSiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=673045).

²³ Abby Fox. Utility-Administered Low-Income Programs in the Southeast (Southeast Energy Efficiency Alliance, 2016). <https://www.seealliance.org/wp-content/uploads/Low-Income-Landscape-Assessment-FINAL.pdf>

1 for them, while also increasing the total numbers of customers and communities that
2 can benefit.

3 Q: IS THERE A NEED FOR ADDITIONAL PROGRAMMING AIMED AT BRINGING BENEFITS TO
4 LMI COMMUNITIES?

5 A: Across Georgia, there are more than 1 million households with an electricity burden
6 greater than 6%, and more than 600,000 households with an electricity burden greater
7 than 10%.²⁴ The median electricity burden in Georgia (currently 3.6%) is likely to rise as
8 GPC rates continue to increase – the Company is requesting a \$1 billion increase, a 12%
9 increase to retail rates that would “result in an increase of approximately \$16.29 to the
10 monthly bill of a typical residential customer using an average of 1,000 kWh per
11 month.”²⁵ And while many initiatives are in place and even poised to grow as a result of
12 Commission orders, an increasingly-large portion of GPC’s customer base is expected to
13 continue to live with above average, high (6-10%) or severe electricity burden (greater
14 than 10%). Additional options that can deliver benefits to these households can have a
15 transformative positive impact on communities across the state.

16 Q: COULD YOU PROVIDE AN ILLUSTRATION OF HOW AN LMI CUSTOMER COULD BENEFIT
17 FROM MONTHLY NETTING?

18 A: Yes. Table 3 illustrates how net metering bill savings can reduce energy burden. Energy
19 burden is the percentage of household income spent on energy bills, including electric
20 and other fuels such as natural gas or propane. In Table 3 I focus specifically on
21 electricity burden, which is the portion of income spent on the electric bill. The table
22 shows how an example home consuming 1,000 kWh per month (under GPC’s current
23 residential tariff) and with income equal to 100% of the Federal Poverty Level for a

²⁴ Greenlink Equity Map data, accessed November 2022.

²⁵ Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson at 11.

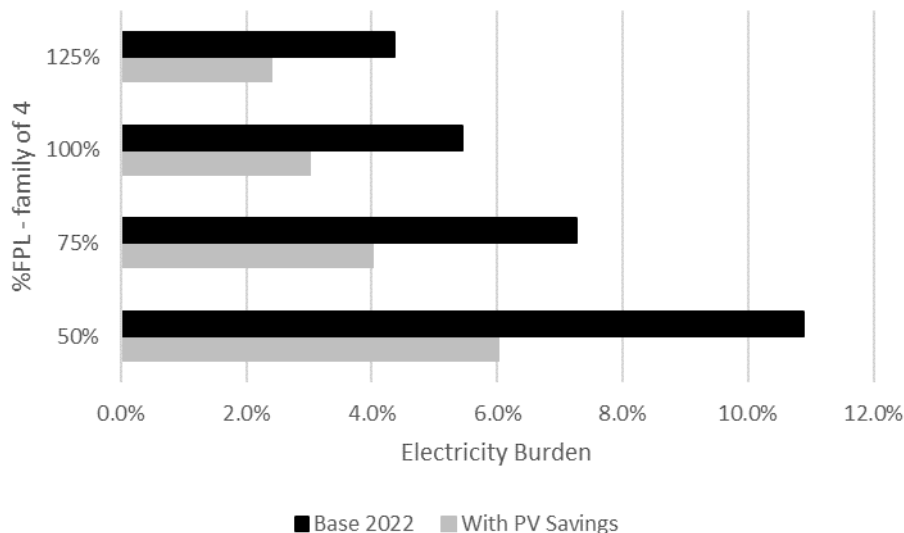
family of four would benefit from monthly netting with a solar PV system sized to produce about half of the amount of electricity consumed by the family.

Table 3. Electricity burden with and without monthly netting for a 4-person HH at 100% FPL

Annual electric bill	\$1,512
Annual income	\$27,750
Electricity burden	5.4%
Annual elec bill w/monthly netting	\$834
Electricity burden w/monthly netting	3.0%

In this example, adding a PV system has the potential to pull this family from nearly high electricity burden to below-average. Further, in Figure 1, I show how households at different income levels could benefit from the same bill savings from Table 3. The effects shown in the figure are similarly transformative, moving households from severe to high, high to above-average, and above-average to below-average electricity burden.

Figure 1. Electricity burden impacts of monthly netting at 4 income levels



Q: WOULD LMI COMMUNITIES EXPERIENCE BENEFITS FROM THE ECONOMIC DEVELOPMENT IMPACTS YOU DESCRIBED ABOVE?

1 A: Yes. Job creation and the additional income flowing into Georgia communities would
2 also benefit LMI communities. And because income is part of the energy burden metric,
3 these economic development benefits can further reduce energy burden.

4 The average salary for solar industry jobs in the analysis I present above is \$59,000, with
5 indirect jobs earning \$53,000 on average and induced jobs earning an average of
6 \$42,000. For a household at or below the FPL, obtaining a job in the local solar industry
7 could increase household income considerably, and for many of these households
8 would pull them out of high or even severe energy burden.

9 For example, most of the census tracts in Ware and Clinch counties served by GPC have
10 high electricity burdens, and several have severe electricity burdens. Thousands of
11 households in these example counties have incomes at or below the federal poverty
12 level. A Ware County family of four at the FPL spending \$2,600 annually on electricity
13 with an income of \$27,750 would have an electricity burden of 9.4%. If the household's
14 income was provided by an average solar industry job paying \$59,000, the family's
15 electricity burden would be reduced to 4.4%.²⁶

16 Q: WHAT OTHER BENEFITS COULD GEORGIA'S LMI COMMUNITIES SEE FROM EXPANDED
17 MONTHLY NETTING?

18 A: A monthly netting program broadly available to GPC customers would leverage the
19 market growth and cost-reducing impacts of non-LMI adopters of rooftop solar PV. Non-
20 LMI customers generally find it easier to access renewable energy financing and take
21 advantage of federal tax credits. The lower barriers faced by these customers can lend
22 stability and geographic diversity to rooftop solar market growth, thus helping to push
23 down costs more consistently across counties and over time. These effects facilitate LMI
24 customer adoption and support their access to the benefits of rooftop solar PV. Further,

²⁶ Clinch and Ware County electricity bill and income data referenced here from Greenlink Equity Map, accessed November 2022.

1 non-LMI adoption deepens the economic development impacts that could benefit LMI
2 communities and helps spread those impacts more widely across Georgia.

3 Q: OVERALL, WHAT IMPACT COULD GEORGIA'S LMI COMMUNITIES SEE FROM EXPANDED
4 MONTHLY NETTING?

5 A: Considering both the bill savings opportunities and the job creation that would be
6 driven by the growing local solar market, tens of thousands of households across the
7 state could see significant improvements in their energy burden, thus driving significant
8 equity gains within GPC territory. As discussed above, at a 3% participation level, about
9 80,000 customers could experience considerable bill savings from rooftop PV, while
10 creating 2,400 full-time jobs with salaries averaging much higher than the annual
11 income of many lower income households. Even at this very modest participation level,
12 large numbers of Georgians could experience a dramatic improvement in their financial
13 status. LMI customer choice will have been increased through additional program
14 offerings. And the bill savings that LMI communities would ultimately realize would be
15 enhanced through the cost-reducing impacts of wider Georgia adoption of rooftop solar
16 PV. Similarly, a broadly available monthly netting program would support elevated
17 economic development impacts that would widen the potential for LMI communities to
18 obtain jobs and increase household income through solar market growth.

19 Q: PLEASE PROVIDE YOUR CONCLUSIONS RELATED TO LMI CUSTOMER MONTHLY NETTING
20 BENEFITS.

21 A: My conclusions on LMI customer monthly netting benefits are as follows:

- 22 • While the Georgia Public Service Commission has provided for substantial
23 programming aimed at benefiting LMI customers, a large need remains, and
24 expanded monthly netting is an appropriate addition to the suite of program
25 choices available to these customers

- Both the economic development impacts and the bill savings potentials from a monthly netting expansion would have dramatically positive impacts on household finances for lower income customers, in many cases pulling them out of severe or high energy burden
- The geographic and volumetric solar market boosts achieved by broad participation in a monthly netting program would increase the numbers of new jobs that could be obtained within LMI communities and would drive down rooftop solar prices, thereby enhancing the net bill savings LMI customers realize.

IV. DESIGNING AN INCLUSIVE MONTHLY NETTING PROGRAM

Q: HOW CAN A MONTHLY NETTING PROGRAM BE DESIGNED TO BE INCLUSIVE OF LMI COMMUNITIES, AS DISCUSSED ABOVE?

A: I recommend considering three factors that can guide program design toward extending the benefits of an expanded monthly netting program to a broad and diverse cross-section of GPC customers. Importantly, this encompasses promoting inclusion of LMI communities and thus driving equity gains in Georgia:

- Place-based approach to programming,
- Forging partnerships, and
- Leveraging financial support

Q: PLEASE ELABORATE ON CONSIDERATION OF A PLACE-BASED APPROACH TO PROGRAMMING.

A: Income and other economic and social indicators vary greatly by geography. Figure 2 below illustrates this point with the wide variation of electricity burden across Georgia

counties, from a low of under 2% to a high of over 10%.²⁷ Indeed, electricity burden and other metrics also vary at a finer level of granularity, as shown in Figure 3, which zooms in on Savannah, Georgia as an example.²⁸ In 2019, electricity burden in individual census tracts ranged from a low of under 2% to a high of over 16% in Savannah.

Figure 2: Electricity burden in Georgia, by county.

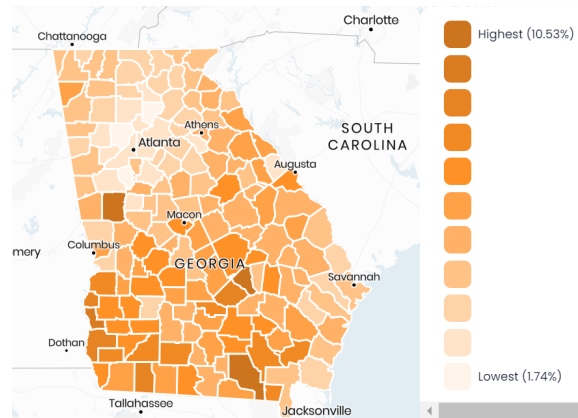
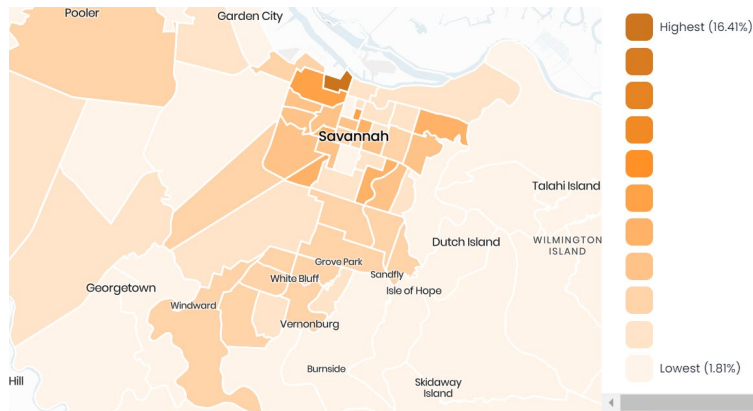


Figure 3: Electricity burden in Savannah, GA by census tract.



A place-based approach to programming considers such data on income, demographics, electricity burden, and other factors to strategically determine where and how to focus

²⁷ Greenlink Equity Map, electricity burden by county for the state of Georgia, accessed November 2022.

²⁸ Greenlink Equity Map, electricity burden by census tract for the Savannah, GA area, accessed November 2022.

1 program resources and efforts. LMI communities will receive greater shares of program
2 benefits if such location-specific considerations guide program implementation.

3 Q: PLEASE ELABORATE ON FORGING PARTNERSHIPS.

4 A: Effective partnerships can serve numerous critical functions in the process of developing
5 and implementing a program intended to reach a wide audience, including increasing
6 shares of LMI participation. These include:

- 7 1. Coordinating program administration
- 8 2. Successfully combining services and incentives from multiple
9 organizations and programs
- 10 3. Achieving trust and educating and marketing within communities

11 A recent NRRI report notes that "project experience demonstrates that special attention
12 is needed to effectively combine and coordinate multiple low-income programs and
13 implement ideas about how best to deliver solar benefits to low-income customers."²⁹
14 The report further spotlights several tested strategies for coordinating administration
15 and combining multiple programs, including a "one-stop shop" platform, use of trained
16 navigators to help customers understand offerings, and use of working groups to guide
17 program development.

18 The Low-Income Solar Policy Guide emphasizes the importance of community
19 engagement throughout the process of program development and implementation,

²⁹ Tom Stanton. Solar Energy that Pays for Low-Income Customers and Communities (National Regulatory Research Institute (December 2020) at 3. <https://pubs.naruc.org/pub/46965D7D-155D-0A36-315D-58319B591EB8>

1 noting that "Engagement should include partnerships with trusted local community-
2 based organizations, which can help educate and enroll customers."³⁰

3 Workforce training is another key objective to emphasize in a program aiming to include
4 LMI communities in the positive economic development impacts that would accrue with
5 expanded monthly netting. Partnerships with organizations that provide such training
6 can prepare community members with the knowledge and skills to obtain employment
7 in the solar industry and in firms expanding due to indirect and induced economic
8 impacts.

9 In sum, partnerships among entities such as community-based organizations, solar
10 installers, Georgia Power, and state and local officials could be a powerful means of
11 coordinating various financial support mechanisms, engaging with communities, and
12 streamlining enrollment processes, all of which would support GPC customer access to
13 an expanded monthly netting program, with potential to substantially boost LMI
14 customer adoption of rooftop solar PV. One potential venue for forging such
15 partnerships could be a working group analogous to the Distributed Generation Working
16 Group ("DGWG") created under the 2022 IRP order³¹, except in this case focused on
17 rooftop solar PV.

18 Q: PLEASE ELABORATE ON LEVERAGING FINANCIAL SUPPORT.

19 A: A Lawrence Berkeley National Laboratory study released in 2022 found that while
20 rooftop solar financial incentives have generally been phased down over time in the US

³⁰ Environmental Law and Policy Center et al. Low-Income Solar Policy Guide: Principles and Recommendations for Utility Participation in Solar Programs for Low-Income Customers (2020) at 15, <https://www.lowincomesolar.org/wp-content/uploads/2020/01/Utility-LMI-Solar-paper.pdf>

³¹ Georgia Public Service Commission Docket Nos. 44160 and 44161, Order Adopting Stipulation at 44-45.

1 by policy design, financial incentives still drive PV adoption by LMI households that
2 would not have otherwise happened.³²

3 NREL's Low- and Moderate-Income Solar Policy Basics web publication discusses the
4 importance of financial support for extending solar access to LMI populations.³³ NREL
5 lists both direct incentives such as rebates towards the cost of PV systems and
6 supplemental bill credits, as well as credit- and financing-related mechanisms such as
7 loan loss reserves, on-bill financing, and revised underwriting criteria. Potential funding
8 sources listed include the Low-Income Home Energy Assistance Program ("LIHEAP"), the
9 Weatherization Assistance Program ("WAP"), and Community Development Financial
10 Institutions ("CDFIs").

11 The Inflation Reduction Act ("IRA") represents another opportunity to leverage federal
12 funding in support of LMI customers realizing benefits from customer-sited solar PV.
13 Several programs created by the IRA are viable sources of funds, including the
14 Greenhouse Gas Reduction Fund³⁴, the Climate Pollution Reduction Grants program³⁵,
15 and the Environmental and Climate Justice Block Grants program³⁶. These three
16 programs represent approximately \$35 billion of funding, including grants and financing,
17 that are not dependent on a household's ability to benefit from tax credits. Multiple
18 programs could be layered on top of one another to provide both direct incentives and
19 financing to a wide range of low-income and disadvantaged communities.

20 Q: WHAT MIGHT A SUCCESSFUL PROGRAM DESIGN LOOK LIKE, CONSIDERING THE THREE
21 FACTORS?

³² Eric O'Shaughnessy. Rooftop solar incentives remain effective for low- and moderate-income adoption (Lawrence Berkeley National Laboratory, April 2022).

³³ <https://www.nrel.gov/state-local-tribal/lmi-solar.html>

³⁴ IRA Section 60103

³⁵ IRA Section 60114

³⁶ IRA Section 60201

1 A: An alliance of Georgia stakeholders could form that would provide for coordinated
2 action to greatly enhance the level of net metering benefits realized by LMI
3 communities. Trusted local organizations could serve as community liaisons and support
4 community participation in development and implementation of an LMI rooftop solar
5 program, ensuring that LMI communities are at the center of these efforts. State and
6 local officials could work with communities and Georgia Power to use a data-driven
7 approach to focus on specific geographies across Georgia, achieving an appropriate
8 place-based program rollout. All parties would collaborate on applying for funding
9 under the IRA as well as leveraging existing funding under LIHEAP, WAP, and other
10 sources. Through a combination of IRA and existing LMI-targeted funding, rebates
11 and/or other financial support would be provided to LMI households in order to offset
12 costs and maximize their bill savings from net metering. And parties would develop a
13 one-stop-shop or similar mechanism for administering the financial support, place-
14 based programming, workforce training, and other key functions.

15 Q. PLEASE PROVIDE YOUR CONCLUSIONS ON DESIGNING AN INCLUSIVE MONTHLY
16 NETTING PROGRAM.

17 A: My conclusions on program design are as follows:

- 18 • A greater share of the benefits of net metering can be channeled into LMI
19 communities through place-based programming, effective partnerships, and
20 leveraging financial support from the IRA and other sources
- 21 • A working group similar to the DGWG but dedicated to rooftop PV issues could
22 be a means to forging partnerships and coordinating financial support
23 mechanisms and program administration.

V. RNR TARIFF PROPOSAL AND RESPONSES TO GPC WITNESSES

Q: WHAT CHANGES DO YOU PROPOSE TO THE RNR TARIFF MOVING FORWARD?

A: I propose that the existing limitations on customer access to the retail rate monthly netting provisions of the RNR-10 tariff be removed. In other words, I recommend lifting the customer count and capacity limits on monthly netting participation.

This would enable Georgia Power customers to participate more widely in the successful monthly netting program, paving the way for the economic development and bill savings benefits presented in my testimony to be attained.

Q: DO YOU HAVE ANY COMMENTS ON THE SUPPLEMENTAL RNR-10 TESTIMONY OF COMPANY WITNESSES EVANS AND LEGG?

A: Yes, I'd like to comment on the cost shift claims, the recommended 3-part rate, and consumer protections.

First, Witnesses Evans and Legg state that "...the Company has made an adjustment of approximately \$1.4 million to rates related to the projected cost shift from the monthly netting pilot."³⁷ My testimony does not include analysis of the Company's alleged cost shift claims or methodology; however, taking it at face value, it's important to recognize how tiny this figure is in relation to the Georgia Power system. The Company's 2021 revenues totaled \$8.48 billion,³⁸ meaning less than 0.02% of the Company's revenues would account for the alleged monthly netting cost shift.³⁹ Again taking this figure at face value, under a modest expansion, as envisioned in my testimony and calculations, the level of revenue implicated in monthly netting would remain minimal. This

³⁷ Supplemental Testimony of Evans and Legg at 11, lines 19-21.

³⁸ US EIA Form 861 data.

³⁹ Stated on a per-customer basis, the 5,000 customer limit on the current monthly netting pilot is less than 0.2% of GPC's customer base.

1 conclusion is in line with recent research and analysis finding that at low participation
2 levels, the impact of rooftop solar PV on retail rates is negligible.⁴⁰

3 Second, GPC is proposing to require "all customers who enroll in RNR on or after
4 January 1, 2023 to take service under a three-part rate"⁴¹ consisting of a customer
5 charge, a demand charge, and an energy charge. However, the Company hasn't
6 provided evidence that RNR customers have a distinctive usage pattern that warrants
7 grouping them together as a separate customer class and forcing them to take service
8 under a particular rate tariff. Other customers continue to have options as to which
9 tariff they take service under, including customers who adopt technologies or behaviors
10 that impact their usage patterns. In the absence of such evidence, taking away these
11 customers' ability to choose their rate tariff is discriminatory and should be rejected.

12 Third, Witnesses Evans and Legg support "...the development of a more formal
13 framework..." for consumer protections related to rooftop solar.⁴² A reasonable,
14 collaboratively developed approach to consumer protections for the rooftop solar
15 industry aligns well with the goal of expanding the benefits of rooftop solar across
16 Georgia. This could be an additional topic for development under a rooftop solar
17 working group, as discussed above.

18 Q: DO YOU HAVE ANY COMMENT ON THE SUPPLEMENTAL RNR-10 TESTIMONY OF
19 COMPANY WITNESS GATTIE?

20 A: Yes, I'd like to comment on Witness Gattie's view of Georgia's policy choices and on his
21 assertions about the implications of the IRA.

⁴⁰ Galen Barbose. Putting the Potential Rate Impacts of Distributed Solar into Context (Lawrence Berkeley National Laboratory, 2017). <https://eta-publications.lbl.gov/sites/default/files/lbnl-1007060.pdf>

⁴¹ Supplemental Testimony of Evans and Legg at 14, lines 4-5.

⁴² Supplemental Testimony of Evans and Legg at 16.

1 First, Witness Gattie focuses on California and its evolving net metering policy. The
2 Georgia rooftop solar market, unlike the market in California, is in relative infancy. What
3 California regulators and policymakers are debating with respect to net metering and
4 distributed generation has little relevance to Georgia at this stage. Witness Gattie fails
5 to note that most states have implemented a net metering policy as I reference above,
6 and many have embraced net metering as a means to grow a rooftop solar market that
7 is far larger than the existing market in Georgia.⁴³ States such as California and Arizona
8 are adapting their policies only after capturing the benefits of years of robust growth in
9 this sector, which Georgia has not experienced thus far.

10 Second, Witness Gattie claims that "As a result of the IRA, Georgia is likely to see
11 considerable growth in the rooftop solar market in the coming years—without any
12 modification to Georgia's existing compensation structures for customer-owned
13 generation."⁴⁴ Yet he offers no Georgia-specific analysis supporting this claim. As I've
14 described, retail net metering is simple for customers to understand, creates a value
15 proposition conducive to customer adoption of the technology, and has a tried-and-true
16 track record of success. While the IRA extends tax credits that will be useful to some
17 customers and provides funds that a variety of local and state entities may apply for,
18 without net metering in place locally in Georgia, these incentives (even if they are
19 available to customers) may not significantly impact Georgia's rooftop solar market
20 trajectory. As I noted previously, the creation of the monthly netting pilot resulted in a
21 step-change in rooftop solar adoption in GPC territory even though tax credits have
22 been available for many years before the pilot. Customers, especially in LMI
23 communities, are likely to struggle with the value proposition of rooftop solar under the
24 3-part rate approach advocated by the Company or under instantaneous netting. To
25 understand the financial implications of such tariff approaches, customers must
26 consider the timing of their own demand, the timing of PV generation, how those

⁴³ Table 1 above shows distributed generation relative to customer counts by state, with Georgia near the bottom nationally, and many Southeastern and other states with far more distributed generation than Georgia.

⁴⁴ Supplemental Testimony of Gattie at 23, lines 15-17.

1 overlap, and how the rate structure impacts their bills with and without rooftop solar.
2 Such complexity is likely to pose a significant barrier to adoption, even with direct
3 incentives and financing solutions in place. Retail net metering, by contrast, represents a
4 simple and proven tariff approach both nationally and in Georgia, whereby IRA
5 incentives may be leveraged to complement net metering policy and make rooftop solar
6 a viable option with pronounced benefits for LMI communities.

7
8 **VI. CONCLUSIONS AND RECOMMENDATIONS**
9

10 Q: PLEASE SUMMARIZE THE CONCLUSIONS YOU'VE MADE THROUGHOUT YOUR
11 TESTIMONY.

12 A: Net metering is a tried-and-true rate design approach to enabling customer-sited solar
13 PV. A modest increase in monthly netting participation across GPC territory would have
14 widespread benefits, including creation of 2,400 jobs and \$75 million in annual bill
15 savings, as well as enhanced customer choice, a variety of system-wide benefits, and a
16 maturing local rooftop solar market with further reduced PV prices. All customers would
17 benefit, with increasing distributed generation participation providing a range of direct
18 and indirect benefits to customers.

19 Expanding net metering would promote equity across Georgia as well. LMI and
20 disadvantaged communities have been adopters of rooftop solar nationally and in
21 Georgia. And with intentional programming, even more of the benefits of an expanded
22 monthly netting program could flow into these communities and provide a much-
23 needed financial boost. A dedicated working group could coordinate financial support
24 from sources such as IRA programs and LIHEAP, ensure streamlined program
25 administration, provide for workforce training, and help to educate and enroll

1 customers, all in a place-based approach. This working group could also develop a
2 rooftop PV consumer protections framework.

3 Q: WHAT RECOMMENDATIONS ARE YOU MAKING RELATED TO THE RNR-10 TARIFF?

4 A: First, I recommend that the customer and capacity limits on the RNR tariff's monthly
5 netting provisions be lifted.

6 Second, I recommend that GPC's request to force rooftop solar PV adopters onto a 3-
7 part rate be rejected, and that customers adopting rooftop solar continue to be
8 permitted to choose their own service tariff.

9 Third, I recommend that a rooftop solar working group be formed to include GPC, PIA
10 Staff, rooftop solar installers, community-based organizations, city officials, and others
11 with the capacity to contribute to defining and executing financial support, partnership
12 actions discussed in my testimony, and place-based programming. Further, I
13 recommend that the same or similar working group be tasked with collaboratively
14 developing reasonable rooftop PV consumer protections.

15 Q: DOES THIS CONCLUDE YOUR TESTIMONY?

16 A: Yes.

17

18

Table 4: Economic Development Impacts of 1% Monthly Netting

	Direct	Indirect	Induced	Total
Employment	492	129	186	807
Income (\$M)	95	22	31	148
GSP (\$M)	31	10	66	107

Table 5: Economic Development Impacts of 2% Monthly Netting

	Direct	Indirect	Induced	Total
Employment	985	258	373	1,615
Income (\$M)	191	44	62	297
GSP (\$M)	62	20	133	215

Table 6: Bill Savings by Participation

	Customer Savings (\$M)
1%	24.9
2%	49.8
3%	74.7

1 MADAM CHAIR PRIDEMORE: Please continue.

2 BY MR. MORELAND:

3 Q Mr. Sercy, do you have a summary of your
4 testimony prepared today?

5 A Yes, I do.

6 MR. MORELAND: Madam Chair, we ask he could do
7 so now?

8 MADAM CHAIR PRIDEMORE: Please go ahead,
9 Mr. Sercy.

10 A Good morning, Chair Pridemore and members of
11 the Commission. I am providing testimony on behalf of the
12 Georgia Solar Energy Association, also known as Georgia
13 Solar, the oldest solar education and advocacy organization
14 in the state of Georgia.

15 My testimony relates to the structure and
16 pricing of the RNR-10 tariff and its customer impact. I
17 focus on the economic development that would be expected
18 under an expanded monthly netting program, as well as
19 electric bill savings and how these benefits could impact
20 Georgia Power customers.

21 I also highlight how intentional programming
22 could channel additional shares of the benefits of an
23 expanded monthly netting program into low- and
24 moderate-income communities and provide a much-needed
25 financial boost, thus promoting equity across the state.

1 I begin by making note of the proven track
2 record of retail net metering as an approach for enabling
3 customer-sited solar PV, both nationally and in Georgia.
4 Net metering is in widespread use and is considered a
5 foundational policy for rooftop solar market growth.

6 Georgia currently has among the lowest shares
7 of rooftop solar in the country, which means a significant
8 opportunity exists for rooftop solar market growth across
9 the state.

10 Next, I present quantitative analysis of some
11 of the benefits that Georgia communities could enjoy under
12 an expansion of the GPC monthly netting pilot. I used the
13 M-plan macroeconomic model to estimate the changes to
14 Georgia's economy for several illustrative net metering
15 participation levels.

16 At 3 percent of Georgia Power's customer base,
17 or about 80,000 customers, I estimate that over 2,400 net
18 jobs would be created, considering direct, indirect, and
19 induced economic development impacts.

20 I also estimated total electric bill savings
21 for the same 80,000-customer net metering participation
22 level and found an annual savings of \$75 million.

23 Finally, I quantified the impact of both the
24 economic development and the bill savings on example
25 low-income households, finding that obtaining a job in a

1 growing rooftop solar market or participating in an expanded
2 monthly netting program could have a transformative effect
3 on household finances, pulling families out of high or even
4 severe electricity burden.

5 I discussed how all GPC customers experience
6 benefits from adding rooftop solar to the grid. The
7 economic development and bill savings benefits I've
8 estimated would be expected to flow to a wide range of
9 Georgians in different parts of the state and at different
10 income levels.

11 Data on residential solar adopter trends in
12 Georgia shows that 15 percent of the state's recent solar
13 adopters were households below 200 percent of the federal
14 poverty level; 8 percent were below 150 percent of the
15 federal poverty level; and 6 percent were in disadvantaged
16 communities.

17 In addition to participant benefits, the value
18 of multiple system-wide factors accrues to all customers.
19 For example, reduced strain on the grid, increased fuel
20 diversity, and reduced public health impacts.

21 My testimony goes on to discuss how an expanded
22 monthly netting program could be intentionally designed to
23 promote inclusion of LMI communities and drive equity gains
24 in Georgia. I describe three key considerations: A
25 place-based approach, forging partnerships, and leveraging

1 financial support. I'll summarize each of these now.

2 In a place-based approach, data on the
3 geographic variations and income demographics, electricity
4 burdens, and other factors are used to strategically
5 determine where and how to focus program resources and
6 efforts.

7 The second consideration, forging partnerships,
8 is crucial for coordinating program administration,
9 combining multiple services and incentives, and achieving
10 trust within communities.

11 Third, leveraging financial support entails
12 accessing existing funding sources like LIHEAP and new
13 sources such as Inflation Reduction Act programs to maximize
14 net metering bill savings.

15 These considerations are a means to greatly
16 enhancing the level of net metering benefits realized by LMI
17 communities across Georgia.

18 I make three recommendations in my testimony:
19 Drawing on the historical success of net metering, the
20 quantitative analyses presented in my testimony, and the
21 program design considerations I discussed.

22 First, I recommend that the customer and
23 capacity limits on the RNR tariffs' monthly netting
24 provisions be lifted. Second, I recommend that GPC's
25 request to force rooftop solar PV adopters onto a three-part

1 rate be rejected, and that customers adopting rooftop solar
2 continue to be permitted to choose their own service tariff.

3 Third, I recommend that a rooftop solar working
4 group be formed. The working group would include GPC, PIA
5 staff, rooftop solar installers, community-based
6 organizations, city officials, and others with the capacity
7 to define and execute financial support, partnership actions
8 discussed in my testimony, and place-based programming.

9 Further, I recommend that the same or similar
10 working group be tasked with collaboratively developing
11 reasonable rooftop PV consumer protections.

12 Thank you very much, Chair Pridemore and
13 Commissioners. This concludes my testimony summary.

14 MADAM CHAIR PRIDEMORE: Questions from
15 Commissioners? Commissioner Shaw?

16 COMMISSIONER SHAW: Yes, sir. In your
17 testimony where you referenced some economic impacts
18 from an expansion or from your recommendations, you
19 referenced the creation of 2,400 jobs and 75 million
20 in annual bill savings.

21 What numbers are you using to come up with that
22 impact in terms of the -- is it a percentage of
23 customers? Is it a certain amount of customers? can
24 you explain that?

25 MR. SERCY: Yes, I can. So I looked at three

1 different potential participation levels. 1 percent,
2 2 percent, and 3 percent of Georgia Power's customer
3 base. So the 2,400 employment result was for the
4 3 percent case. So that's about 80,000 customers.

5 So what I did is I used a macroeconomic model
6 that looks at Georgia's economy, and it looks at
7 about 550 different industry sectors, everything from
8 different types of agricultural products to
9 manufacturing to health care, restaurants and
10 entertainment, everything in between. And it lets
11 you ask the question: If I take some action, if I
12 build a manufacturing plant, if I build a new road,
13 how does that change Georgia's economy?

14 And so the question I ask is, if you installed
15 80,000 rooftop solar systems in Georgia, how would
16 that affect Georgia's economy?

17 And so the model, then, takes your assumptions
18 about what is involved in doing those rooftop PV
19 installations -- the electrical work, the contracting
20 work on the roof, all the administrative and
21 management positions that are involved in the
22 industry -- and it says, what kind of employment
23 impacts would we see based on that and based on the
24 addition of all of those systems? What kind of
25 income growth would we see? How would gross state

1 product change? So that's what these results are
2 from.

3 And so we see the 2,400 total jobs is
4 considering what's called direct, indirect, and
5 induced jobs. Direct jobs are the direct installing
6 the solar PV systems. Indirect are the company that
7 installed the systems bought things from other
8 companies. Some of those are Georgia companies.
9 That created demand. That created jobs.

10 And then induced are all of the folks -- all of
11 the job creation from direct and indirect, they go
12 out and they buy things in Georgia; and that creates
13 demand, and that creates jobs. And so it's really
14 looking at the ripple effects across the Georgia
15 economy of installing these rooftop PV systems.

16 And the last thing that I'll say is, this is a
17 net jobs analysis, so it includes looking at the bill
18 savings and accounting for the fact that you've got
19 less demand for utility power, and you are having
20 some negative economic impacts from that lower
21 demand.

22 So all of these numbers that I'm presenting in
23 my testimony, the 2,400 total jobs, for example, it's
24 already netted out, you know, the somewhat negative
25 impacts from buying less power off the grid.

1 COMMISSIONER SHAW: Just one follow-up
2 question, Mr. Sercy. So you are saying, then, that
3 those numbers are based on a number of 80,000
4 customers?

5 MR. SERCY: Yes. That's correct, Commissioner.

6 COMMISSIONER SHAW: In your testimony, you're
7 just saying that's a modest increase. So you're
8 saying that an increase from 5,000 customers to
9 80,000 customers is a modest increase?

10 MR. SERCY: Well, I'm saying that in the scope
11 of the entire system, 2.6 million customers.

12 COMMISSIONER SHAW: Okay. Thank you.

13 MADAM CHAIR PRIDEMORE: Any other questions
14 from Commissioners?

15 (No response.)

16 MADAM CHAIR PRIDEMORE: Okay. Americans for
17 Affordable Clean Energy?

18 MR. GALLOWAY: No questions.

19 MADAM CHAIR PRIDEMORE: ChargePoint?

20 MR. FYKES: No questions, Madam Chair.

21 MADAM CHAIR PRIDEMORE: Coalition of Local
22 Government?

23 MS. BROWN: No questions, Madam Chair.

24 MADAM CHAIR PRIDEMORE: GIPL?

25 MS. WHITFIELD: No questions, Madam Chair.

1 MADAM CHAIR PRIDEMORE: GASEIA?
2 MR. THOMASSON: No questions.
3 MADAM CHAIR PRIDEMORE: MARTA?
4 MS. STURM: No questions.
5 MADAM CHAIR PRIDEMORE: Sierra Club?
6 MS. ARIZA: No questions.
7 MADAM CHAIR PRIDEMORE: SACE?
8 MR. DOWDY: No questions.
9 MADAM CHAIR PRIDEMORE: Georgia Public Service
10 Commission?
11 MR. THOMAS: No questions.
12 MADAM CHAIR PRIDEMORE: Georgia Power?
13 Mr. Thomas, do you have questions for any of these
14 intervenor witnesses?
15 MR. THOMAS: I do not.
16 MADAM CHAIR PRIDEMORE: You do not? Oh, okay.
17 That's unique.
18 Go ahead.
19 MR. MARZO: Thank you, Madam Chair, just very
20 briefly.
21 CROSS-EXAMINATION
22 BY MR. MARZO:
23 Q Good afternoon, Mr. -- is it Sercy?
24 A Yes.
25 Q Did I say that right?

1 A Good afternoon.

2 Q Brandon Marzo on behalf of Georgia Power
3 Company. I just had a few questions for you about your
4 testimony. Your testimony does not include an independent
5 analysis of the cost shift from the monthly netting pilot;
6 is that correct?

7 A That's correct. I did not evaluate the
8 company's calculation of the 1.4 million. I did note that
9 1.4 million compared to, say, the 8.5 billion of total
10 revenues from the company is extremely small, or compared to
11 the billion dollar rate increase requested, it's extremely
12 small. But, no, I didn't do an independent analysis of that
13 calculation or my own calculation of the cost shift. And I
14 don't -- I mean, I -- if we just take the 1.4 million for
15 the sake of argument, I make the observation that it's very
16 small.

17 Q Okay. And I think you answered --

18 MADAM CHAIR PRIDEMORE: Mr. Marzo, can I ask
19 you, straighten the neck of the mic and bring it
20 down. We're having some --

21 MR. MARZO: Straighten it?

22 MADAM CHAIR PRIDEMORE: Straighten it and then
23 bring the whole thing down but from the base.

24 MR. MARZO: Bring this down?

25 MADAM CHAIR PRIDEMORE: This is state

1 government. Our equipment is old, like its
2 commissioners. Straighten it. Straighten the neck.
3 MR. MARZO: Just --
4 MADAM CHAIR PRIDEMORE: Think Bob Barker in the
5 1980s.
6 MR. MARZO: You mean, and bring it down like
7 this.
8 MADAM CHAIR PRIDEMORE: Bring it down from --
9 thank you. Thank you.
10 COMMISSIONER MCDONALD: Did you say old like
11 the commissioner?
12 MADAM CHAIR PRIDEMORE: "Commissioners." Me.
13 Me. Plural.
14 COMMISSIONER MCDONALD: You don't know what old
15 is.
16 MADAM CHAIR PRIDEMORE: No reason to get
17 offended; it was plural.
18 Go ahead, Mr. Marzo.
19 MR. MARZO: Sure.
20 BY MR. MARZO:
21 Q And just to make sure I've got this correct,
22 it's fair to say that you reviewed the company's analysis,
23 and you just concluded that the cost shift in your opinion
24 was tiny? Is that -- is that correct?
25 A Well, that's mostly correct.

1 Q Yes.

2 A I didn't review the company's analysis. I'm
3 just saying if -- I saw in the company's testimony on RNR
4 that you're saying there's a \$1.4 million cost shift. And I
5 just said, if I take that at face value without having
6 assessed the calculations myself, I'm just noting it's
7 extremely small.

8 Q Okay. So that answers my question. So really,
9 when I looked at your testimony before, only four of the 31
10 pages of your testimony even respond to the company's
11 positions on RNR in this case; right?

12 A That sounds right.

13 Q Okay. Are you reviewing something, Mr. Sercy?
14 I don't want to jump in if you're --

15 A No, I hadn't done the page count before, but,
16 yes, that's correct.

17 Q And just briefly, I don't want to spend a lot
18 of time on this, we hit this earlier. I know the
19 commissioners have heard this, but you take issue with
20 Dr. Gattie's references to California, but in your
21 testimony, you don't make any -- you don't make any --
22 provide any evidence that the allegations that are made by
23 Dr. Gattie, that, for example, there is a \$3 billion cost
24 shift in California, you don't refute that; correct?

25 A Well, in my testimony I point out that what is

1 going on with net metering in California doesn't have any
2 relevance to net metering in Georgia, because of the low
3 share of distributed generation currently installed in
4 Georgia. And so Georgia is at a very early stage within
5 rooftop solar market growth.

6 There is a big opportunity, as I have talked
7 about in my testimony, to grow that market. And even with
8 modest growth, you still wouldn't be anywhere close to where
9 California is with net metering. And so, what I take issue
10 with and disagree with is the comparison to California and
11 that that's -- that that's relevant to where Georgia is
12 right now with the rooftop solar market.

13 Q So it's a very similar -- maybe I can cut to
14 the chase here and avoid questions. So very similar to some
15 of the witnesses that we've heard from already, for example,
16 Mr. Hill yesterday, your position is, let's just wait for
17 the problem to get -- to grow, become substantial, before we
18 actually address it. Is that fair?

19 A Well, I don't think it's a problem right now.
20 Again, if I take the 1.4 million at face value, it's such a
21 small number, when you compare that to the benefits that net
22 metering has produced so far, the 1.4 million is very small,
23 and even if you -- you grow the industry to 1 percent or
24 2 percent, or 3 percent, that's modest growth, again. And
25 if you take the company's cost shift calculation as it is,

1 the 1.4 percent is 0.2 percent of the customer base.

2 So if you multiplied that by 10 to get to the
3 2 percent participation level, then you go up to 14 million
4 instead of 1.4 million. 14 million compared to 8.5 billion
5 is still tiny.

6 So it's not a problem now. Whenever you look
7 at all of the benefits that come from the rooftop solar
8 industry in the state, the economic development impacts, the
9 bill savings opportunities for customers, the system-wide
10 benefits that accrue from the rooftop solar, not a problem
11 now. Wouldn't be a problem at modest additional growth.

12 In fact, it's just the opposite. It's a good
13 deal. It's significant job growth, significant system
14 benefits, and significant opportunity for customers to save
15 on their utility bills, including customers that very much
16 need ways to save on their electricity bills. So it is a
17 good deal; not a problem.

18 Q Well, Mr. Sercy, it's not a problem for people
19 who can afford to actually go out and purchase solar panels
20 and put them on their home and put them in place, but
21 wouldn't you agree it is a problem for those who can't do
22 that who are then subsidizing those individuals who are
23 doing that? Correct?

24 A So as I point out in my testimony, based on the
25 data that we have, including the most recent data, low- and

1 moderate-income customers are solar adopters, and customers
2 in disadvantaged communities are solar adopters.

3 So I disagree with the characterization that
4 there aren't any low- and moderate-income customers who
5 adopt rooftop solar and benefit from it and use it to help
6 control their bills, especially with rates going up as much
7 as they are.

8 Q So -- let's look at your data, then. I mean,
9 let's, for example, look at your Table 3, which you talk
10 about electricity burden with and without monthly netting
11 for a four-person household. And in that particular chart,
12 you list out the annual electric bill, annual income -- and
13 this is on page 18 of your testimony -- electricity burden,
14 annual electricity bill with monthly netting, and then you
15 show what it would be with monthly netting/without monthly
16 netting.

17 But the one thing I don't see in this table is
18 the cost for the solar system itself. That's not part of
19 your analysis, is it?

20 A That's correct. And a big part of my testimony
21 is, how do we roll out a net metering program that reaches,
22 not only the LMI customers that you would expect it to reach
23 based on the data that we have right now, which is already
24 significant, but what are the things that you can do to
25 enhance the inclusion of LMI communities and disadvantaged

1 communities.

2 I talk about three different ways to do that.
3 And one of those ways is leveraging financial support.

4 And so, without a doubt, taking advantage of
5 things like LIHEAP, and taking advantage of the new
6 Inflation Reduction Act programs that are being developed
7 right now, will be very important for allowing low- and
8 moderate-income customers to participate more fully and
9 realize as much of the bill-savings benefit as possible, get
10 them as far along towards these electricity burden-reducing
11 impacts as -- as we can.

12 Q So I take all that to mean that Mr. Moreland
13 won't be giving those systems away to low-income customers;
14 right?

15 A Well, I think with a partnership and with
16 coordinated work that obtains funding from different
17 sources, you could certainly set up a program where that's
18 the case.

19 Q And just to close this out, and I won't, once
20 again, try not to revisit things we've covered with other
21 witnesses, but in no way have you refuted the fact that in
22 several jurisdictions, it's been found that low-income
23 customers who don't participate have been disproportionately
24 affected by net metering programs; correct?

25 A I focused on Georgia.

1 Q Okay.

2 A And Georgia is at a very low penetration level
3 right now. It can grow a lot and still be at a very low
4 penetration level. And again, we take the company's cost
5 shift calculation at face value, it's a tiny amount.

6 Q Okay. And that's something we'll disagree on.

7 MR. MARZO: Madam Chair, that's all I have for
8 cross-examination. I thank the Commission for its
9 time.

10 Thank you, Mr. Sercy.

11 THE WITNESS: Thank you.

12 MADAM CHAIR PRIDEMORE: Redirect?

13 MR. MORELAND: Madam Chair, I have no redirect
14 and request that Georgia Solar Exhibits Nos. 1 and 2
15 be admitted into evidence.

16 MADAM CHAIR PRIDEMORE: So moved.

17 (GA Solar Exhibits 1 and 2 were admitted into
18 evidence.)

19 MR. MORELAND: Can the witness be excused?

20 MADAM CHAIR PRIDEMORE: You are excused.

21 MR. SERCY: Thank you.

22 MADAM CHAIR PRIDEMORE: GASEIA?

23 MR. THOMAS: Madam Chair, we don't have
24 questions for intervenors in this round. We did in
25 the last round.

1 MADAM CHAIR PRIDEMORE: Yeah, but in this
2 round. This is all on net metering that staff is
3 proposing should be a policy call of the Commission.
4 I just don't understand why staff wouldn't put any
5 effort to question these witnesses.

6 MR. THOMAS: Well, Madam Chair, in this round,
7 both the company and the staff put forward a
8 proposal. Most of these intervenors focus their
9 criticism on Georgia Power's proposal. If staff were
10 to question these intervenors, I'm afraid it would
11 sound like friendly cross. And I know the Commission
12 wants us to avoid that. And so that's staff's
13 strategy during this round. We did in the last round
14 when we felt like there were areas where it was
15 appropriate.

16 MADAM CHAIR PRIDEMORE: But it's a completely
17 different purpose now. This -- these are only about
18 net metering. Staff hasn't questioned one intervenor
19 witness on the subject of net metering.

20 MR. THOMAS: Right. And I'm saying that staff
21 chose not to do that because we felt like, if we
22 focused on these intervenors with cross, it would
23 come across as friendly cross, and we wanted to avoid
24 that.

25 MADAM CHAIR PRIDEMORE: But you can make that

1 argument about the previous round as well or any time
2 that staff crosses an intervenor witness. You can
3 always make that argument that it's friendly cross or
4 unfriendly cross.

5 What's more important to me is that the staff
6 puts forward questions to help commissioners make
7 decisions, and -- I mean, you can always make that
8 argument, Mr. Thomas, that -- that staff doesn't
9 question intervenor witnesses.

10 MR. THOMAS: Well, we did in the last round
11 because we felt like some of the intervenor testimony
12 criticized some of the staff positions and gave us an
13 opportunity to develop that cross. In this round on
14 the net metering issue, we felt like it would be
15 friendly cross; and like I said, that's just
16 something we're trying to avoid. Staff has tried to
17 put on a case where they present options in response
18 to Commissioner Shaw's motion, and we hope we've
19 helped commissioners in that sense.

20 MADAM CHAIR PRIDEMORE: Well, you haven't
21 helped this commissioner. It's helpful when the
22 staff participates in this process.

23 MR. THOMAS: Well, staff feels like we have;
24 but we thank you for the feedback, Commissioner.

25 MADAM CHAIR PRIDEMORE: Go ahead,

1 Mr. Thomasson.

2 MR. THOMASSON: Commissioner, before I swear
3 in, I would ask permission from Ms. Whitfield to
4 approach with our demonstratives for --

5 MADAM CHAIR PRIDEMORE: Yes, please go ahead.

6 MR. THOMASSON: All right, gentlemen, if you
7 would stand and raise your right hand.

8 Thereupon,

9 THATCHER YOUNG,
10 WILL GIESE,
11 KEVIN LUCAS,
12 having been duly sworn, testified as follows:

13 DIRECT EXAMINATION
14 BY MR. THOMASSON:

15 Q Could you please each state your names, your
16 employer, and your job titles, please.

17 A (Witness Young) Yes. Good morning. My name
18 is Thatcher Young. I am vice president and owner of Velo
19 Solar based at 154 Krog Street, Suite 140, Atlanta, Georgia,
20 30307.

21 A (Witness Giese) My name is Will Giese. I am
22 the southeast regional director for the Solar Energy
23 Industries Association. I believe our address is 1408
24 Northwest K Street, Suite 1000.

25 A (Witness Lucas) Kevin Lucas, senior director
of utility regulation and policy at the Solar Energy
Industries Association. Our address is 1401 K Street --

1 Will doesn't get up there that often -- Washington D.C.,
2 20005.

3 Q On November 18th, did you cause to be filed 83
4 pages of prefiled testimony in this proceeding along with
5 the one exhibit?

6 A (Witness Lucas) Yes.

7 Q And did you also cause to be filed 83 pages of
8 trade secret testimony along with it?

9 A (Witness Lucas) Yes.

10 Q And if I asked you the same questions today as
11 are asked in your prefiled testimony, would your answers be
12 the same?

13 A (Witness Lucas) Yes. I think we did find one
14 typo. Apologies for not having this up in advance.

15 Sorry. I had them marked in my other copy,
16 which I don't have here. It was a typo that was incorrectly
17 referencing a recommendation on the interconnection fee, and
18 it should have been a recommendation related to the RNR
19 tariff. It was just a cut-and-paste error. It wasn't
20 anything of substance.

21 Q Okay. Well, if you can find that --

22 A (Witness Lucas) Yeah, I will try.

23 Q -- during your testimony, maybe we can correct
24 that for the record.

25 Do you have any -- well, I guess we just

1 answered if you have any other corrections.

2 MR. THOMASSON: Madam Chair, I'd ask that the
3 prefiled testimony be copied into the record as if
4 read.

5 MADAM CHAIR PRIDEMORE: So moved.

6 (Whereupon, the prefiled testimony of Thatcher
7 Young, Will Giese, and Kevin Lucas follows:)

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BEFORE THE PUBLIC SERVICE COMMISSION

STATE OF GEORGIA

**In Re: Georgia Power Company's
2022 Rate Case**

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Docket No. 44280

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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1 I. INTRODUCTION AND QUALIFICATIONS

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

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

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

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

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

13 A2. [Mr. Lucas] Yes.

14 A2. [Mr. Young] Yes.

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

16 **Q3. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?**

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

20 **Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

21 A4. The purpose of our testimony is to respond to the Georgia Power Company’s (“Georgia
22 Power”, “GPC”, or “the Company”) supplemental direct testimony in this proceeding that
23 focused on RNR customers.¹

24 **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”).

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

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

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

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

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

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

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

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

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

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

12 **Q6. WHAT ARE YOUR OVERALL RECOMMENDATIONS?**

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

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

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

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

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

6 **Q8. PLEASE SUMMARIZE YOUR FINDINGS.**

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

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

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

22 A9. We implore the Commission to reject GPC's unsupported opposition to expanded RNR
23 monthly netting and move forward with an expansion of the pilot program until such time as
24 GPC adopts a more rigorous, cost-based approach to this issue. The Commission ordered
25 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.

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

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

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

16 **Q10. PLEASE REVIEW THE HISTORY OF PARTIES’ RNR TESTIMONY IN THE 2022 IRP AND THIS**
17 **CASE.**

18 A10. Beginning in the 2022 IRP case, the Company advanced arguments claiming that RNR
19 Monthly Netting customers were causing a “cost shift” to other customers.⁵ GPC claimed
20 that RNR Monthly customers caused a \$382,000 and \$968,000 revenue erosion in 2020 and
21 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”)

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

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

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

11 Rather than continuing to try to address rooftop solar with a series of temporary and
12 partial measures where some customers receive net metering while others receive
13 only avoided cost or, in some cases, nothing at all, I move that the Commission direct
14 Staff and the Company to each address the appropriate structure and pricing of the
15 RNR-10 tariff in the current rate case so that the Commission can move towards a
16 fair and long term way of addressing the issue.

17
18 In this IRP, we simply do not have the cost information necessary to set just and
19 reasonable rates, terms, and conditions for rooftop solar. In addition, we do not have
20 the information to determine whether or how such rates, terms, and conditions would
21 impact other customers. Under my motion, the parties in the rate case would have the
22 opportunity to provide, test, and challenge cost-based data and the Commission
23 would have more options than simply deciding whether or not to continue
24 temporarily doling out net metering to a subset of customers.¹⁰

25 Fast forwarding to the current rate case, the Company reintroduced its revenue
26 erosion analysis in the first phase of this docket. GPC proposed to adjust its target base
27 revenue requirement by \$1.4 million, claiming that it was necessary to recoup revenue loss
28 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.

1 the IRP related to unspecified operational issues and an increase in “bad actors” in the BTM
2 solar market.¹²

3 In the first phase of this case, GASEIA Intervenor again rebutted the Company’s
4 revenue erosion claims, pointing out again the lack of any cost of service analysis to support
5 its “cost shift” claim. After all, one cannot credibly claim that revenue erosion causes a cost
6 shift without actually analyzing whether costs fell by a commensurate amount; if costs fall
7 from \$10 to \$7, then a corresponding revenue reduction from \$10 to \$7 does not cause a cost
8 shift. We also contrasted the magnitude of the purported RNR Monthly Netting revenue shift
9 (\$0.20 per year for a typical residential customer) with the Company’s requests in this case
10 (\$195 per year), the projection of Vogtle costs (\$166 per year), and the excess revenue
11 collection above its central ROE but below the ROE dead band (\$46 in 2021.)¹³

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

22 **Q11. HAS THE COMMISSION RECENTLY OPINED ON THE NEED FOR A COST-BASED ANALYSIS OF**
23 **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 Intervenor 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.

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

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

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

9 **Q13. WHAT ARE YOU BASING THAT CONCLUSION ON?**

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

19 GPC was also asked in discovery to elaborate on its RNR testimony on this point.
20 The Company was asked to “provide all data, studies and analyses that have been performed
21 by, or on behalf of, the Company regarding cost shifting, revenue erosion, or that indicate
22 rooftop solar customers on the RNR Monthly Netting tariff are not paying their full cost of
23 service.” The Company responded with workpapers that further supported its revenue
24 erosion analysis found in Witness Evans’ and Legg’s supplemental testimony but did not
25 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.

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

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

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

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

18 Its load values are calculated to the nearest [REDACTED].²¹ For 12CP allocators, this produces
19 values at a resolution of roughly [REDACTED]. For 4CP allocators, the resolution is [REDACTED]. Sales
20 are loaded into the model at the [REDACTED] resolution for higher voltage levels B through F and at
21 the [REDACTED] level – or [REDACTED] significant digits – for voltage level G.²² Line losses are
22 also recorded to the [REDACTED] level, producing a line loss factor that is presented to [REDACTED] decimals
23 of precision. Revenue is entered to the nearest [REDACTED], also recorded at [REDACTED] significant
24 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.

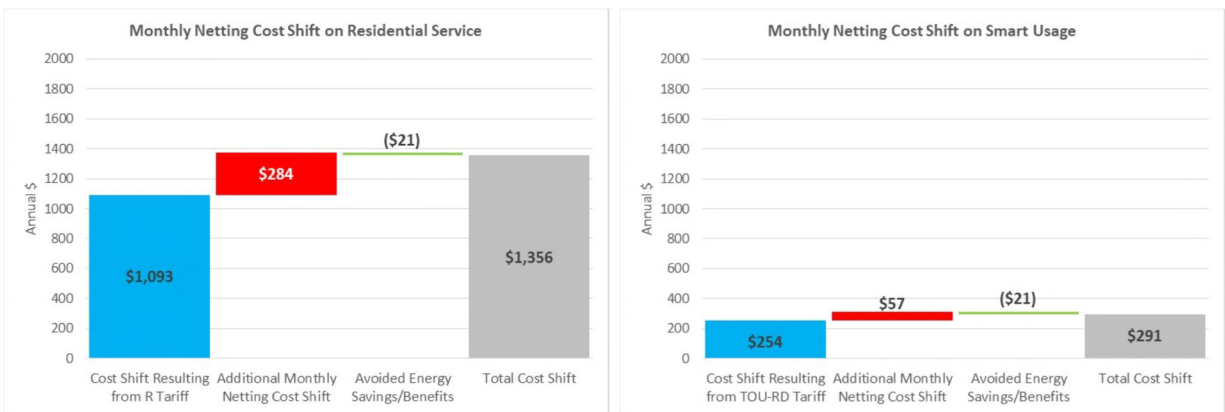
²⁵ Exhibit LPE-1 and LPE-2.

²⁶ STF-TAI-1-27 Attachment A.

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

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

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



11
12 *Figure 1 - GPC Monthly Netting Cost Shift Analysis*

13 **Q17. WHAT WAS YOUR INITIAL RESPONSE TO THIS ANALYSIS?**

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

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

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

7 **Q19. WHAT IS YOUR IMPRESSION OF THE COMPANY’S ANALYSIS?**

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

11 **Q20. WHAT IS THAT ISSUE?**

12 A20. The workpaper has a glaring error: the bill for usage over 1,000 kWh in summer months for
13 the R tariff is multiplied by 2.²⁹ This is due to a mistake in a formula where rather than
14 rounding the value to 2 decimal places, the workpaper multiplies this value by 2.

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

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

22 Second, the workpaper also includes a direct comparison of bills between the R and
23 TOU-RD rate, including for pre-solar customers. Due to the error, the 4th quartile customer
24 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.

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

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

8 **Q22. WHAT HAPPENS WHEN YOU CORRECT THIS ERROR?**

9 A22. The Company’s cost shift argument is severely wounded. Because the error occurred only on
10 one component (pre-solar use on the R tariff), its impact was maximized. Correcting only
11 this error and rerunning the Company’s analysis produces substantially different results. The
12 \$1,093 of “cost shift” from the R tariff falls to \$560. So instead of the R tariff causing \$840
13 more per year in “cost shift” than the TOU-RD tariff, the value falls to \$305. Even without
14 addressing the many other issues with the Company’s analysis, this alone slashes the impact
15 of and justification for requiring new RNR customers to move to three-part rates.

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

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

19 A23. Yes, it did.

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

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

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

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

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

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

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

13 Included in this response is the Cost of Service model used by Georgia Power in its
14 cost of service study (the "Software"). The Software is a working, proprietary Cost of
15 Service model. The Software is being provided solely for PIA Staff's review in
16 connection with the 2022 Rate Case. **Use of the Software by others is strictly**
17 **prohibited.** The Software should not be shared with anyone, including consultants,
18 who have not signed a consultant acknowledgement or equivalent confidentiality
19 agreement with Georgia Power. While the resulting numbers from the Software are
20 not necessarily trade secret information, **Georgia Power will consider any**
21 **unauthorized use of the Software itself to constitute misappropriation of a trade**
22 **secret in violation of the Georgia Trade Secrets Act of 1990, O.C.G.A. § 10-1-**
23 **760 et seq., as well as violation of Commission rules.**

24
25 The Software and any attendant documentation contain valuable intellectual property
26 and proprietary information belonging to Georgia Power and Southern Company. The
27 Software is provided for review as a single product. **Its component parts may not**
28 **be separated for use. Reproduction or distribution of the Software source code,**
29 **object code, or any copy thereof is strictly prohibited.** All title and copyrights in
30 and to the Software, any accompanying printed materials, and any copies of the
31 Software, are owned by Georgia Power and its parent and/or affiliates. The Software
32 is protected by copyright laws and international treaty provisions.³¹

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

³¹ STF-TAI-1-1. Emphasis added.

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

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

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

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

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

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

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

3 A30. Staff had filed a data request on September 16, 2022, asking “all data, studies and analyses
4 ... regarding cost shifting, revenue erosion, or that indicate rooftop solar customers on the
5 RNR Monthly Netting tariff are not paying their full cost of service.”³² The response to this
6 request was due October 17, 2022. The Company responded on that day saying it would
7 update its response after filing its RNR testimony, due on October 20, 2020. On October 21,
8 2022, the Company supplemented its response to include workpapers associated with the
9 revenue erosion analysis.

10 On October 27, Staff filed another set of data requests that asked more detailed
11 questions about the Company’s RNR testimony and requested hourly data and system
12 information for 2018-2021 “for all RNR customers.”³³ Under the shortened discovery
13 timeline for the RNR phase of the proceeding, responses were due Wednesday, November 9,
14 2022, directly in the middle of the first round of intervenor hearings. This was nine days
15 before intervenor RNR testimony was due on Friday, November 18, 2022.

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

23 On Monday, November 14, 2022, at nearly 9 PM, GASEIA Intervenors were notified
24 by the Company that supplemental files had been created. While the supplemental file did
25 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.

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

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

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

20 The system information file contains only one date element, titled “Established
21 Date.” Of the 7,297 systems identified in this file, only 14 had established dates prior to
22 2020.³⁷ However, the 2019 hourly data file contained more than 700 customers with
23 exported energy.³⁸ Given it is not possible for a customer to have exported energy prior to
24 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.

1 interconnection. More likely it represents the date that a customer (many of whom had
2 existing solar systems) was added to the RNR tariff, which is not what was requested.

3 GASEIA informed the Company of these continued issues with its supplemental responses
4 on the afternoon of Tuesday November 15, 2022.

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

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

15 **Q32. WHAT IS YOUR RESPONSE TO THESE CLAIMS?**

16 A32. The Company’s claims are simply inaccurate. The Company provided an example of a
17 customer that came online in October 2020 would not be included in the hourly data file, but
18 sure enough, there were in fact 72 customers that came online in October 2020 that were in
19 the hourly data file. In fact, many systems that came online in the middle of the year were
20 present in the hourly data files. In the 2019 file, only 520 of the 721 customers had data on
21 1/1/2019. In the 2020 file, only 650 of the 1,169 had data on 1/1/2020. In both files,
22 customers were added throughout the year, contrary to the Company’s claims that it only
23 provided customers with 12 months of data in a given year.

24 Likewise, the contention that the Established Date was “very closely aligned” with
25 the interconnection date is readily disproved in the data. Only two customers had Established
26 Dates in 2019 (both in December), but there were 721 customers that showed outflow during
27 2019. Unless the Company is claiming that all of these customers improperly interconnected

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

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

7 **Q33. WHAT IS THE RESULT OF THIS DISCOVERY ISSUE?**

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

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

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

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

³⁹ Legg Direct at 5

⁴⁰ STF-TAI-1-27 Attachment A.

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

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

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

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

10 **Q37. PLEASE EXPLAIN FURTHER.**

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

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

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

⁴¹ GASEIA Intervenor IRP Direct at 39.

⁴² See e.g., GASEIA Intervenor 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.

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

5 The only way that the revenue adjustment would not simply add to the Company's
6 revenue surplus is if it were earning less than the Commission-approved ROE, which is
7 currently set at 10.5%. This has never happened since 2011. And even if the Company is
8 earning below its central ROE value, it does not have any recourse to seek recovery of those
9 revenues unless the ROE falls below the bottom of the ROE dead band, currently set at 9.5%.
10 Given Southern Company's recent 2022 Q3 earnings report, it appears that 2022 will be
11 another banner year for GPC, with 2022 year-to-date net income 80% higher than in
12 2021.^{46,47}

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

18 **Q38. DESPITE THE COHERENT LOGIC OF YOUR PREVIOUS ARGUMENT, HAS GPC INVESTIGATED**
19 **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>

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

6 It continued:

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

15 **Q39. WHAT IS YOUR REACTION TO THIS RESPONSE?**

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

25 The only limit to its claim is if there is a “comparable reduction in the Company’s
26 retail cost of service / revenue requirement.” But of course, it simultaneously claims that no
27 action can reduce the embedded cost of service of its system, and that its tools and models do
28 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.

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

6 **Q40. IS THIS INTERPRETATION CONSISTENT WITH THE COMPANY’S OTHER TESTIMONY?**

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

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

23 **Q41. DO YOU AGREE WITH THIS INTERPRETATION?**

24 A41. No. While we agree that GPC is *allowed* to keep money above its central ROE and the upper
25 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.

1 the revenue requirement calculated at the central ROE represents the best and most
2 appropriate value for profits. If the Commission truly believed that GPC was *entitled* to a
3 12.0% ROE, then it could have simply established a 12.0% ROE. But it did not do this; it
4 established a 10.5% ROE paired with an earnings band mechanism as part of the multi-year
5 rate plan structure. This is a critical distinction, and one that has major implications for both
6 the requested \$1.4 million RNR adjustment and the Company's arguments about cost shifts
7 in general. Clearly, however, the Company sees this as a distinction without a difference.

8 **Q42. WHY IS THIS DISTINCTION IMPORTANT?**

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

13 A reasonable revenue requirement would include one that is calculated based on the
14 central ROE set point. Given that GPC is only entitled to an opportunity to earn these
15 revenues, it is hard to understand why it believes "appropriate ratemaking principles" would
16 dictate that it "must recover" any and all revenue erosion at any point in its earnings band.
17 To put numbers to this argument, in 2021 GPC collected \$258.0 million more than what a
18 10.5% ROE would have dictated.⁵² Here, it argues that it is entitled to collect another \$1.4
19 million for RNR revenue erosion and push its surplus revenue to \$259.4 million. The hubris
20 in this claim is astonishing, particularly considering the massive, multi-billion dollar rate
21 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.

1 **III. GEORGIA POWER’S RNR QUANTITATIVE ANALYSES ARE FLAWED, NOT COST**
2 **BASED, AND SHOULD BE REJECTED**

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

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

8 **Q44. PLEASE SUMMARIZE YOUR FINDINGS.**

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

17 **Q45. WHAT IS YOUR RECOMMENDATION ON THE COMPANY’S ANALYSIS?**

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

23 *The Company’s Analysis is Flawed, Uses Dubious Assumptions, and Discards Critical Data*

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

1 A46. In the IRP docket earlier this year and in the first phase of this rate case, the Company
2 produced an analysis that compared retail bills from customers on the RNR Monthly Netting
3 and RNR Instantaneous tariffs. It calculated the difference between these two bills and
4 labeled the delta as a “cost shift.” We have discussed the flaws in this analysis extensively in
5 both the IRP⁵³ and first phase of the rate case.⁵⁴

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

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

⁵³ GASEIA Intervenor’s IRP Direct at 39.

⁵⁴ GASEIA Intervenor’s Direct Section IV.

⁵⁵ STF-TAI-7-1 Revised.

⁵⁶ STF-TAI-7 Attachment A.

⁵⁷ STF-TAI-7-1 Revised.

1 there would have been \$6.9 million in revenue erosion, with each customer causing a \$1,377
2 annual “cost shift.”⁵⁸

3 **Q47. WHAT IS YOUR IMPRESSION OF THIS ANALYSIS?**

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

12 **Q48. ARE THERE PARTICULAR CHOICES THAT YOU DISAGREE WITH OR MISTAKES YOU FOUND IN**
13 **THE COMPANY’S ANALYSIS?**

14 A48. Yes, there are myriad, listed below.

- 15 • **GPC fails to conduct the analysis at an individual customer level.** This is critical as net
16 load is a function of both solar generation and household use, and bills are a non-linear
17 function of net load. Averaging out 1,110 customers into four quartiles removes all the
18 variation that is inherent in individual customer’s usages.
- 19 • **GPC calculation of the “pre-solar” loads overstates generation and is not representative**
20 **of the RNR customer group.** The Company was asked for “all data, studies and analyses”
21 used in its analysis.⁵⁹ Nowhere in the initial round of workpapers did the Company
22 demonstrate how it calculated the pre-solar loads. In a subsequent round of discovery, the
23 Company provided its methodology, which was to simply assume that every PV system had a
24 16.3% capacity factor and a 120% AC to DC ratio.⁶⁰ These values are indicative of ideal,
25 unshaded, south-facing roofs with insolation attainable in only some parts of the state.
26 Applying this solar production to every RNR system overestimates how much solar is
27 produced, which overstates the “pre-solar” values used in subsequent analyses.
- 28 • **GPC uses four non-solar customers as the basis for its entire analysis.** There is
29 considerable risk in selecting only four customers to represent the entire RNR pilot program.
30 No data about whether these customers are representative of the broader customer basis is
31 provided. It is unknown whether they use electric or gas heating, whether they live in a rural
32 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 necessary 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.

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

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

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

16 A49. We recommend the Commission give it little weight. Putting aside the major calculation
17 error discussed above and the PVWatts daylight saving time error, the approach to condense
18 1,110 customers into four customers was done without sufficient consideration of the
19 individual usage variation and the non-linear nature of rates. The Company admitted that it
20 did not produce “a formal model or worksheet that would be considered to be ‘analysis.’”⁶⁸
21 The subsequent decision to expand those four customers to represent 1,110 and 5,000
22 customers assumes the usage profiles are representative of the pilot customer base, a fact
23 which the Company did not establish.

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

⁶⁶ Id.

⁶⁷ Evans and Legg Supplemental at 12.

⁶⁸ STF-TAI-8-3

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.

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

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

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

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

23 These characteristics are separate and distinct from revenue collected through
24 different ratees. For example, suppose a utility had a rate where every customer paid a fixed
25 \$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.

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

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

9 A55. Yes. Michigan has a statute that requires export compensation for BTM systems to be cost-
10 based.⁷⁴ DTE Energy (“DTE”), a regulated Michigan utility, proposed to implement a grid
11 access charge for solar customers that was predicated on a supposed cost shift that led to a
12 revenue deficiency from BTM DG customers.⁷⁵ This is the exact type of argument made by
13 the Company in this case. The Michigan Public Service Commission rejected DTE Energy’s
14 argument, finding the grid access charge “is neither COS-based, as required by MCL
15 460.6a(14), nor equitable. As ELPC noted, the utility’s method for calculating the [grid
16 access] charge explicitly relied on the distribution revenue deficiency and not on any cost to
17 serve.”⁷⁶ While Georgia does not have a similar statute regarding cost-base export rates for
18 BTM DG customers, it is instructive that another utility commission reviewed and rejected
19 claims that a rate design / revenue erosion argument for BTM DG customer was compatible
20 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).

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

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

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

11 **Q57. PLEASE SUMMARIZE YOUR FINDINGS.**

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

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

25 A58. We recommend the Commission recognize the myriad benefits that BTM solar brings to
26 Georgia. In addition to helping customers control their bills in a time of rising prices, it
27 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.

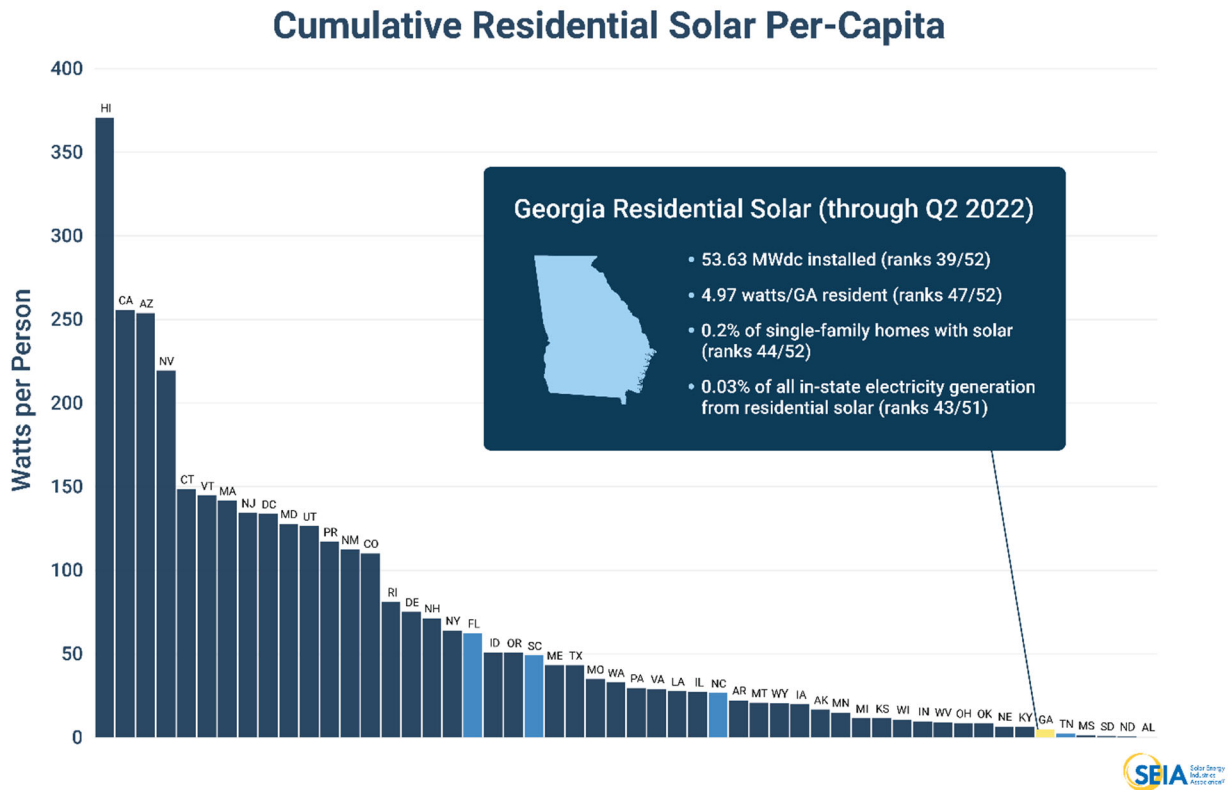


Figure 2 - Georgia Residential Solar Per-Capita

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.

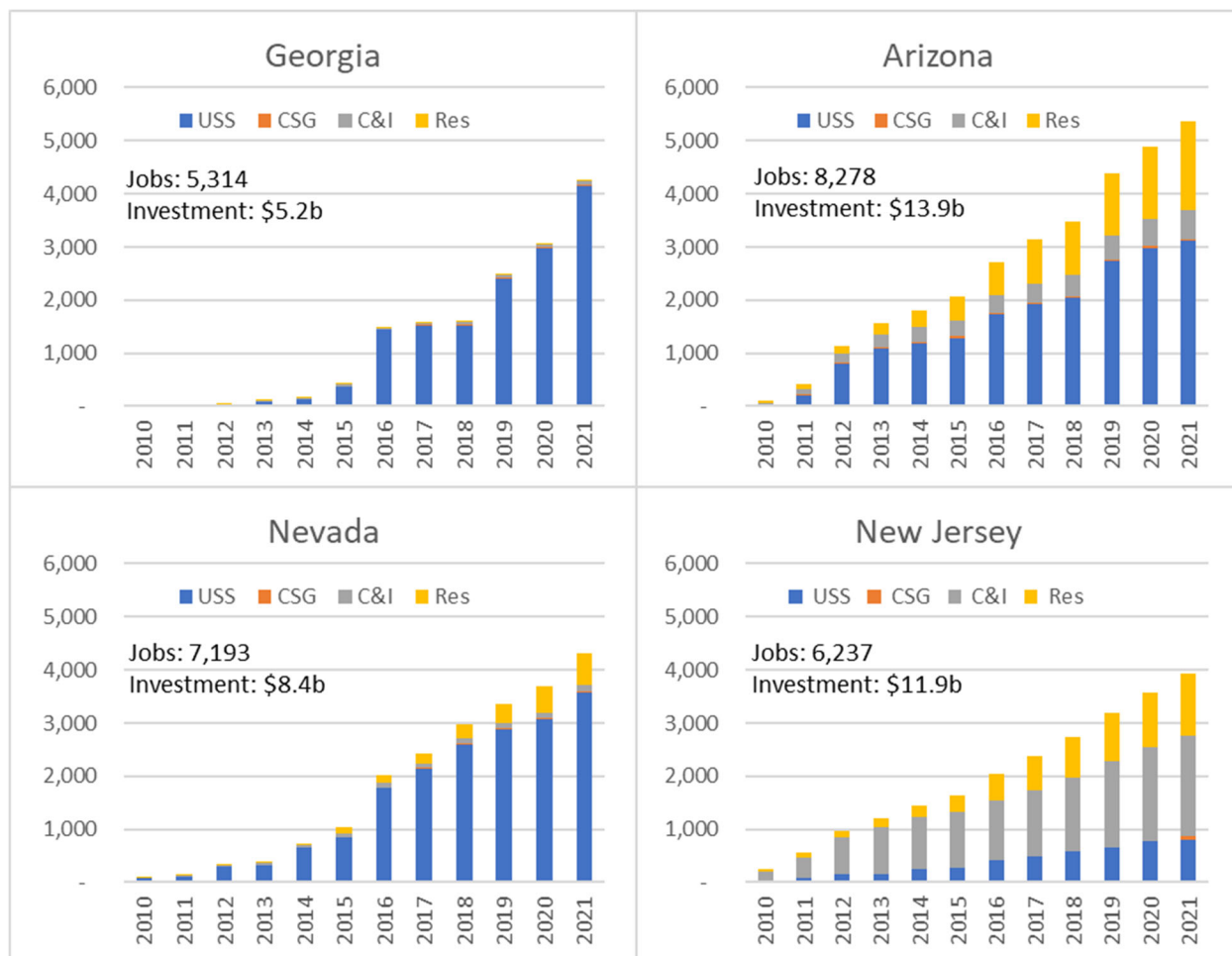


Figure 3 - Capacity, Jobs, and Investment of Selected States

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 Census⁷⁹ 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/>

1 *Other States that are “Walking Back” Net Metering Still Have More Generous Policies than Georgia*

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

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

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

10 **Q64. DID THE COMPANY PROVIDE SUPPORT FOR THIS POSITION?**

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

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

15 A65. Conventional net metering remains the law of the land in many states. While it is true that
16 some states such as those listed above are transitioning to post-NEM structures, most of the
17 country continues to utilize net metering as the default. In fact, as of spring 2022, 33 states
18 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.

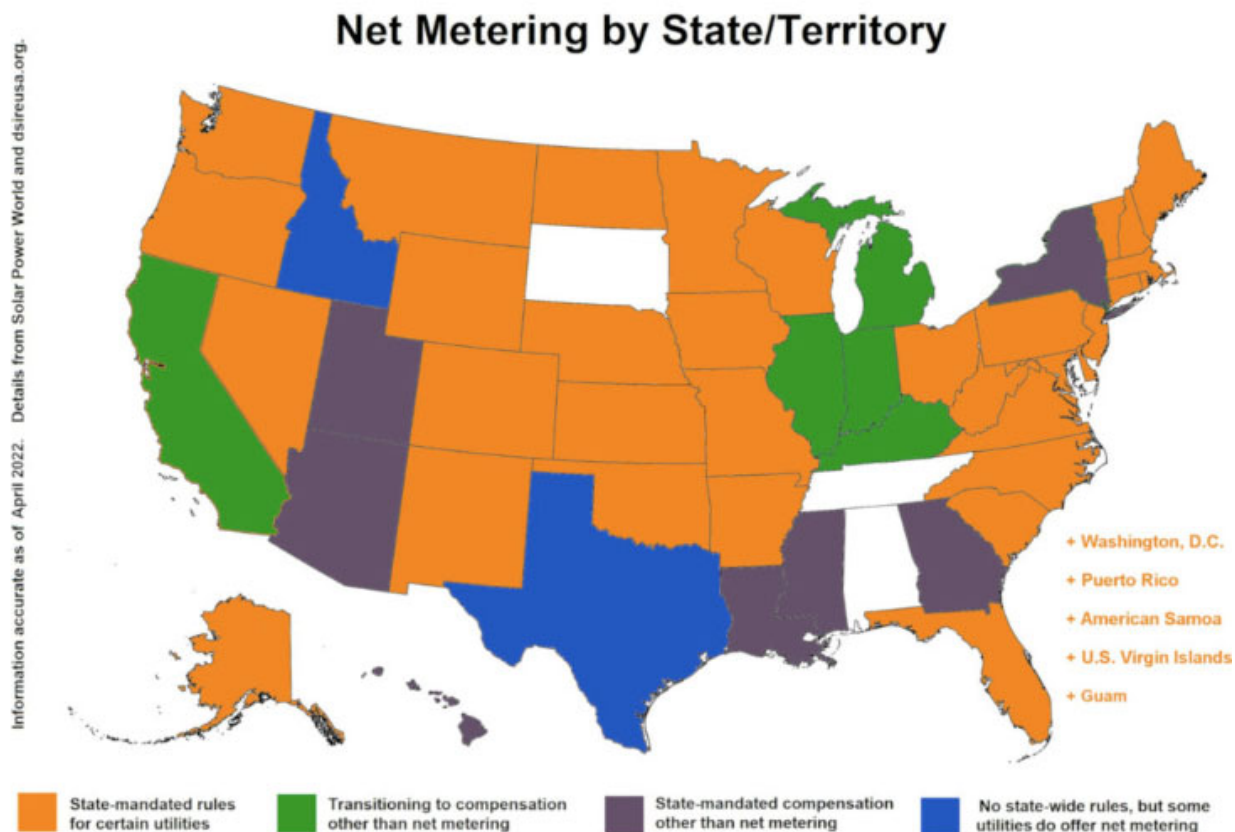


Figure 4 - Net Metering Policy State Map

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/>

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

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

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

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

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

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

⁸⁹

<https://mgaleg.maryland.gov/mgaweb/Legislation/Details/sb0407?ys=2021RS>.
<https://mgaleg.maryland.gov/mgaweb/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

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

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

5 A69. We do not dispute the figures he produced, but we do believe his commentary is overstated.
6 For instance, he clearly implies that California's focus on decarbonization has led to
7 reliability challenges and high rates. In reality, California's reliability issues have been
8 exacerbated in recent years by utility negligence⁹³ and wildfires driven by worsening climate
9 change.⁹⁴ Likewise, Texas's problems during the winter storm a few years ago was caused in
10 large part by its electric and gas industry regulators failing require generators to winterize
11 their equipment, despite having been warned about the potential risk years before after a bad
12 storm in 2011.⁹⁵

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

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

20 **Q71. PLEASE EXPLAIN.**

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

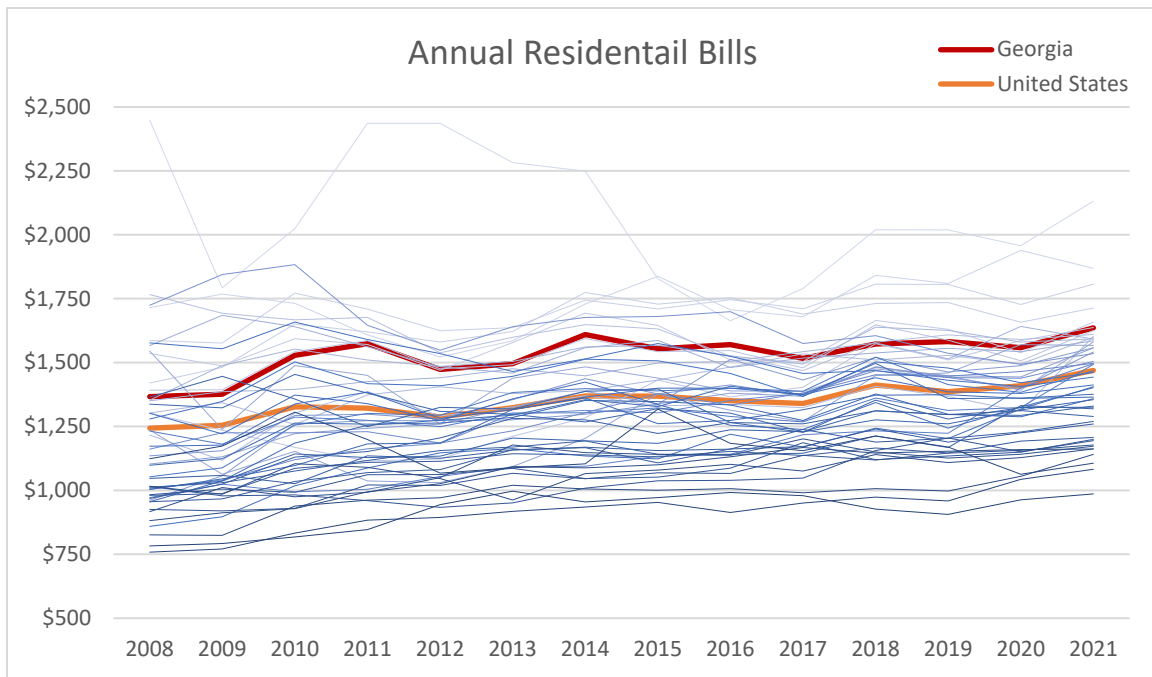
⁹² Gattie Supplemental at 21.

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/>

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



3
4 *Figure 5 - Comparison of Residential Bills*

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

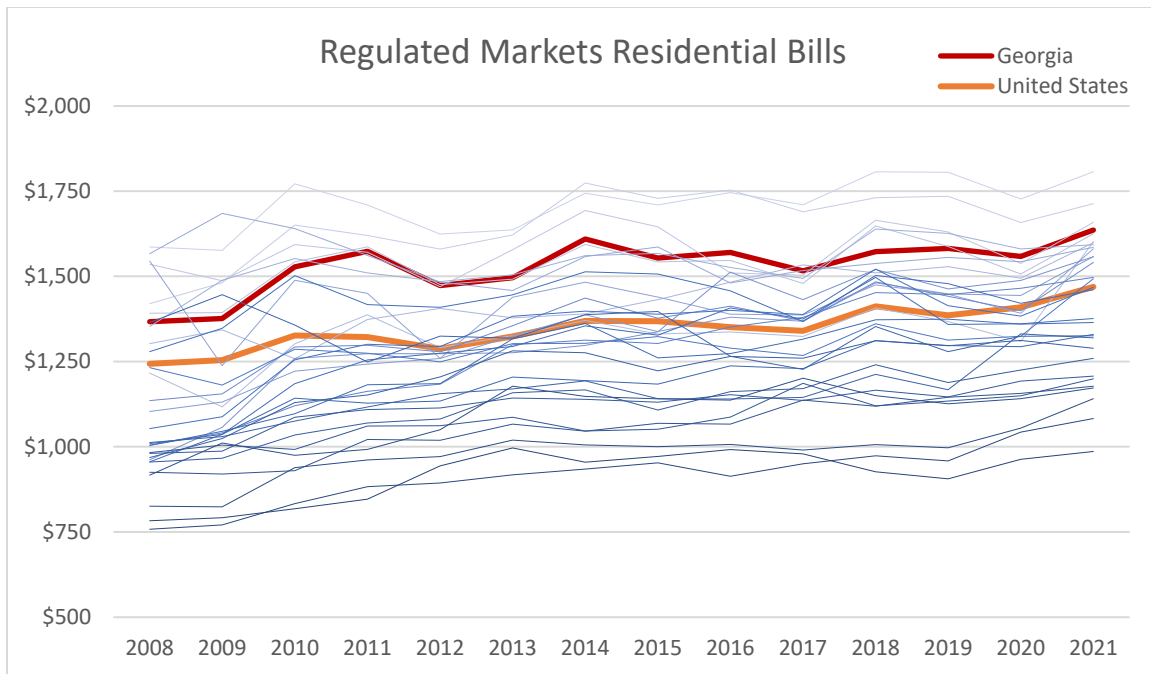


Figure 6 - Regulated Markets Residential Bills

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.

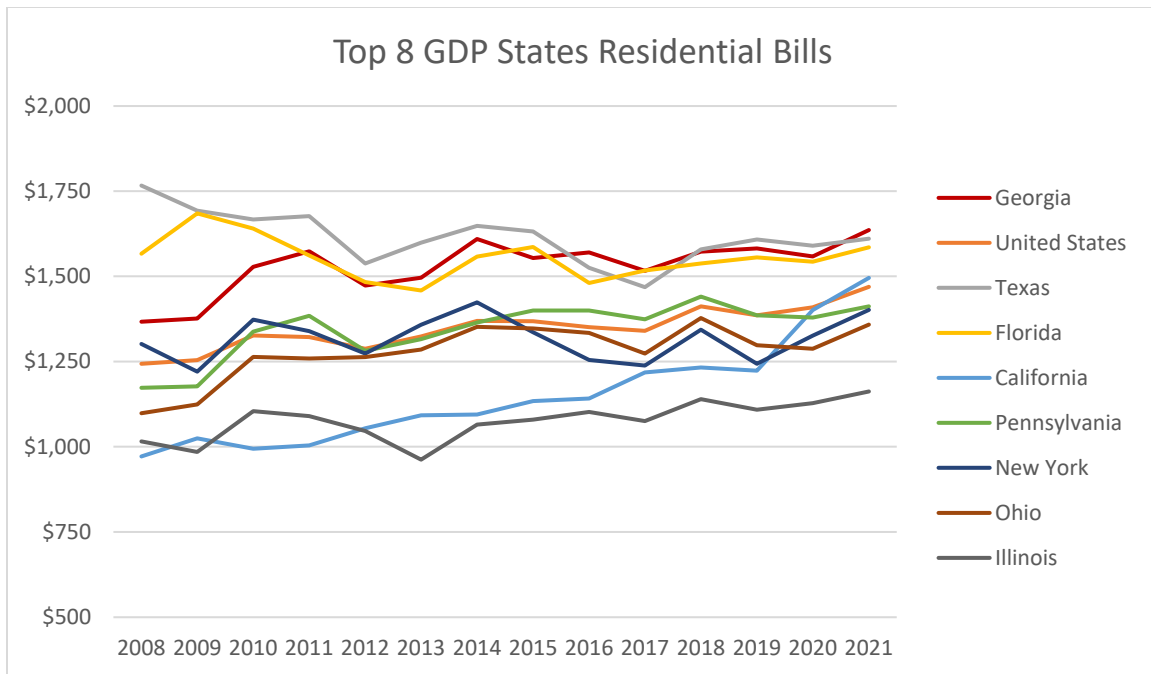


Figure 7 - Top 8 GDP States Residential Bills

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

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

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

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

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

13 **Q76. DOES THE COMPANY PROPOSE TO CHANGE THIS?**

14 A76. Yes. It proposed that all new RNR customers who move to the tariff on or after January 1,
15 2023, must take service on a three-part rate with a demand charge.⁹⁷ For residential
16 customers, the only such tariff is the TOU-RD rate. In the Company’s view, three-part rates
17 “better align with the Company’s underlying costs, and further mitigate the cost shift between
18 participating and non-participating customers.”⁹⁸

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

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

⁹⁷ Evans and Legg Supplemental at 14.

⁹⁸ Id.

⁹⁹ See e.g., GASEIA Intervenor’s Direct at Section V.

¹⁰⁰ Id. at 105.

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

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

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

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

22 **Q79. HAS ANOTHER STATE TESTED THIS APPROACH OF MANDATING BTM PV CUSTOMERS TAKE**
23 **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 Intervenor Direct at 59.

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

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

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

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

15 A81. It is dead last.

16 **Q82. WHAT IS THE BASIS FOR GPC’S PROPOSAL TO SHIFT CUSTOMER TO A DEMAND-BASED**
17 **TARIFF?**

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

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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

¹⁰⁸ Gattie Supplemental at 23.

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

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

- 4 • **Residential customers are not eligible for the Production Tax Credit (“PTC”).** The
5 PTC, which offers a \$0.015/kWh inflation-adjusted credit (currently set to \$0.026/kWh) for
6 renewable energy production, was expanded to make solar an eligible technology, but it is
7 only applicable to commercial taxpayers under Section 48. Residential customers do not
8 qualify. SEIA anticipates that while some utility-scale solar developers may opt for the PTC
9 in certain parts of the country, for higher-cost BTM systems, the investment tax credit
10 (“ITC”) will remain substantially more lucrative.
- 11 • **The residential ITC is not refundable.** Residential customers do qualify for a 30% ITC
12 under Section 25D, but they must have taxable income to offset as the tax credit is not
13 refundable. Non-profit entities are now eligible for direct pay, so this provision might assist
14 non-residential entities such as churches seeking to install BTM solar.
- 15 • **The residential ITC was restored to 30%, but it never went below 26% before.** Prior to
16 the passage of the IRA, the Section 25D residential ITC was scheduled to step down from
17 30% in 2021, to 26% in 2022, to 22% in 2023, and to 0% in 2024 and beyond. However,
18 with the passage of the IRA in 2022, the credit never dropped below 26%. Restoring this
19 credit to 30% is certainly beneficial but it will not have a major impact on the short-term
20 market conditions.
- 21 • **Domestic Content and Energy Community Bonus Credits are only for commercial**
22 **customers.** As with the PTC, the bonus adders for domestic content and energy community
23 locations are only applicable to commercial entities under Section 48. Residential owners
24 will not qualify for these bonus credits.
- 25 • **Commercial projects over 1 MW face new conditions on the full ITC.** Unlike before,
26 when all projects received a 30% ITC, commercial projects that exceed 1 MW will now have
27 to comply with prevailing wage and apprenticeship program requirements in order to receive
28 the full 30% ITC. If they meet none of the new requirements, the projects will only receive
29 a 6% ITC.

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

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

1 Unfortunately, at the same time, other factors impacting the market have driven
2 prices up by well more than the 4% of reestablished ITC. Tariffs continue to be placed on
3 solar cells and modules, and COVID-induced supply chain pinches have impacted the solar
4 market as with many other industries. Likewise, solar projects are not immune to inflation,
5 which has pushed up commodity prices such as steel and aluminum as well as wages. At the
6 same time, the sharp rise in interest rates has made consumer loans and other financing more
7 expensive, further reducing demand. Together, these trends have contributed to push
8 national average prices up from \$3.90/w to \$4.10/w in the first half of 2022.¹⁰⁹ This price
9 jump effectively negates the benefit of the higher ITC. Along with higher inflation, interest
10 rates have also increased. Many customers finance their solar systems with loans, and the
11 jump in personal loan rates is another near-term headwind.

12 SEIA certainly anticipates that the market dynamics will improve, and that the IRA
13 will unleash domestic manufacturing and support the creation of well-paying jobs in the
14 industry. But these benefits will take some time to implement and internalize. In the
15 meantime, support from state policies such as net metering will be critical to help the industry
16 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 unconvincing. 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

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

6 **Q94. WHAT IS THE LOGICAL FLAW IN THIS ARGUMENT?**

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

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

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

18 A95. Yes, it has grown substantially. Figure 8 below shows the net plant in service ("PIS") for the
19 Company by function. The net PIS has climbed from \$15.8 billion in 2011 to \$26.9 billion in
20 2021, a compound average growth rate of 5.5% per year.¹¹² Every rate base component
21 increased in value in every year except for one (production between 2019 and 2020), with the
22 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.

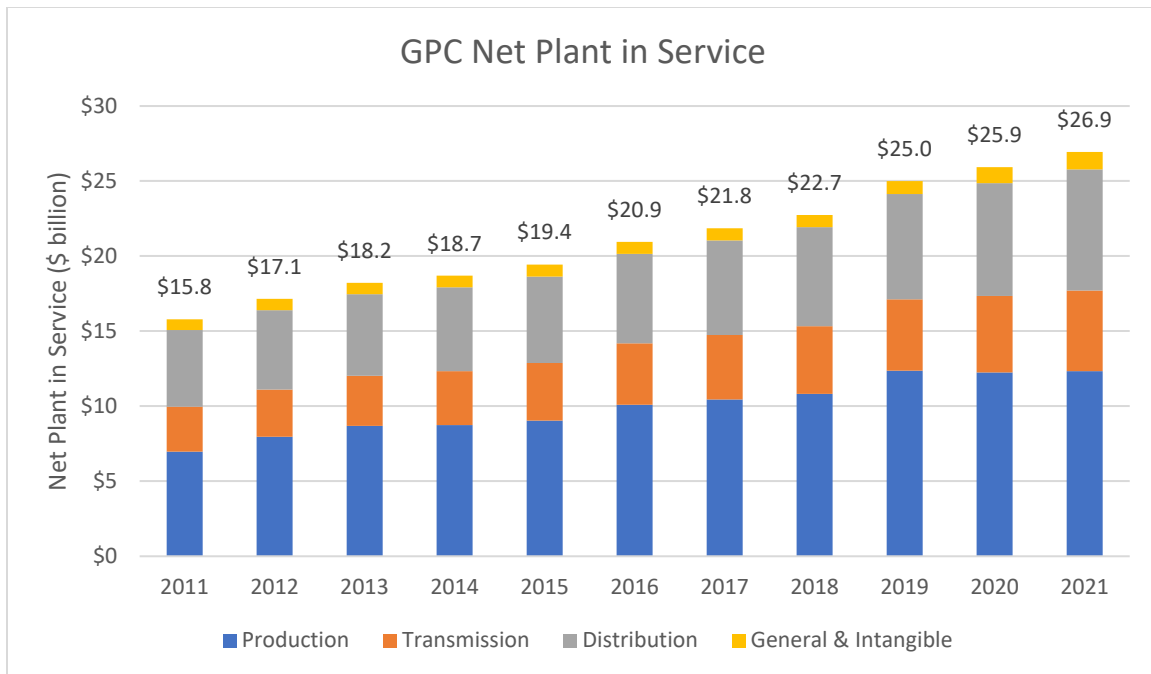


Figure 8 - GPC Net Plant in Service

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.

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

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

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

15 A101. Yes. The Company's load forecasts are based on projections of usage from different sectors.
16 The residential sector forecast includes assumptions about appliance usage and housing
17 stock. GPC, as is typical in the industry, made assumptions about the adoption of efficiency
18 standards such as ENERGY STAR.¹²¹ These factors impact how much energy the Company
19 projects will be used by air conditioners, water heaters, televisions, and other categories.
20 Nowhere in this process does the Company require long-term, fixed commitment contracts to
21 install certain types of air conditioners. Instead, it simply assumes an evolution in the
22 marketplace and incorporates a statistical analysis of air conditioning usage. GPC can and
23 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.

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

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

6 Based on current IEEE standards, there is no offset to any future distribution costs.
7 Consistent with IEEE-1547, the IEEE Standard for Interconnecting Distributed
8 Resources with Electric Power Systems, Southern Company requires all distributed
9 resources (including solar generation facilities) to cease energizing the distribution
10 system upon occurrence of a fault on the distribution system. These resources are
11 required to stay off-line for up to five minutes after the distribution system voltage
12 and frequency are restored to ranges specified in ANSI standard C84.1. Therefore,
13 the distribution system must be capable of serving 100 percent of the customer's load
14 during this timeframe. Further, the distribution system must be capable of serving
15 100 percent of the load when behind-the-meter generation resources are unavailable
16 for any reason. As a result, planning of the distribution system must assume that the
17 feeders containing such generation are still required to carry the full load connected
18 to these circuits, thereby negating any potential deferment of distribution investment,
19 as referenced in the Renewable Cost Benefits Framework filed in the Company's
20 2016 and 2019 IRPs in Docket Nos. 40161 and 42310, respectively.¹²²

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

26 Additionally, it is unclear whether the Companies are referring to the IEEE 1547-
27 2003 standard, or the updated IEEE 1547-2018 standard which was designed with the
28 expectation that DERs installed under this standard will "play and larger role and, overall,
29 improve power quality" in distribution and transmission networks broadly depending on
30 penetration level.¹²⁴

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>

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

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

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

18 The load diversification factor quickly scales as a function of customers, as seen
19 below in Figure 9.¹²⁶ For equipment close to customers such as line transformers, the
20 diversified demand may be 60% lower than the sum of the maximum individual customer
21 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 Transformers²⁹

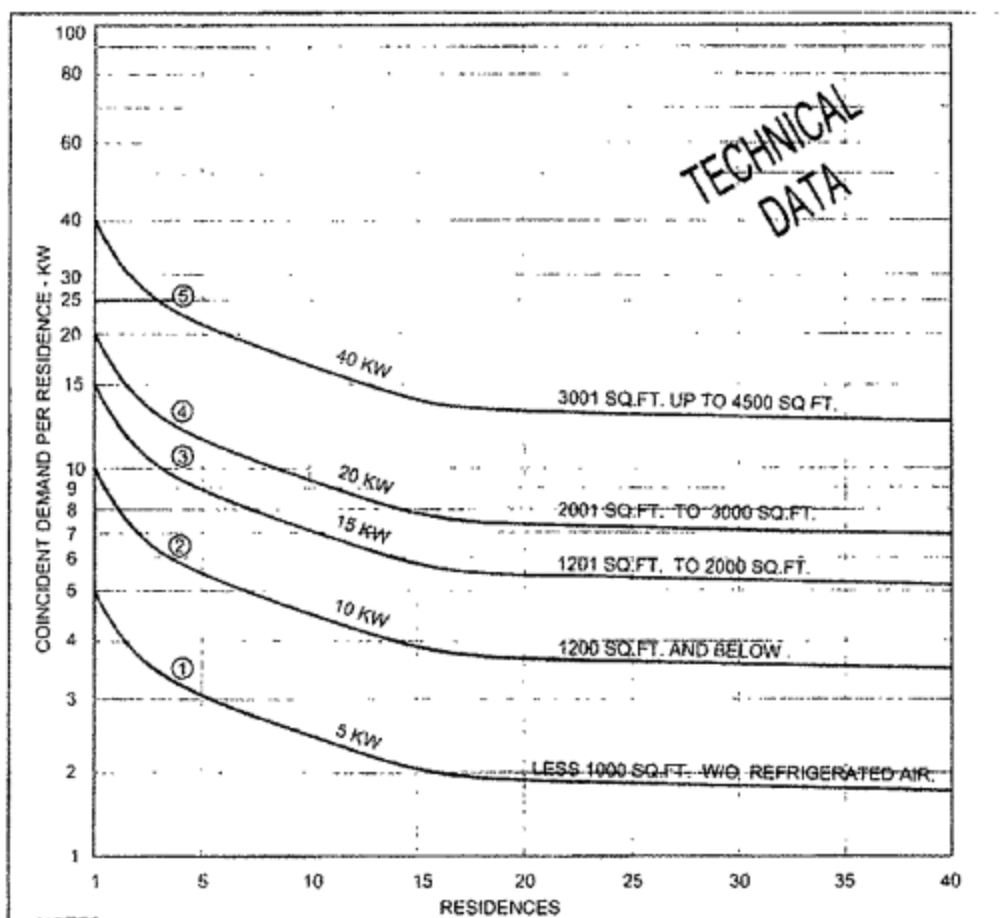


Figure 9 - Residential Load Diversity and Transformer Sizing

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

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

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

14 **Q104. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.**

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

127

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

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

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

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

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

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

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

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

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

10 A109. No, it did not.

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

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

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

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

21 A111. This analysis used hourly load data by tariff¹²⁸ and hourly inflow (power consumed from
22 GPC's grid) and outflow (power exported to GPC's grid) data provided for 1,016 RNR
23 customers in 2021.¹²⁹ The non-RNR customer data set was developed from hourly load data
24 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.

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

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

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

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

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

22 **Q113. HOW DO THE RNR CUSTOMERS AND NON-RNR CUSTOMERS COMPARE IN TERMS OF BASIC**
23 **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.

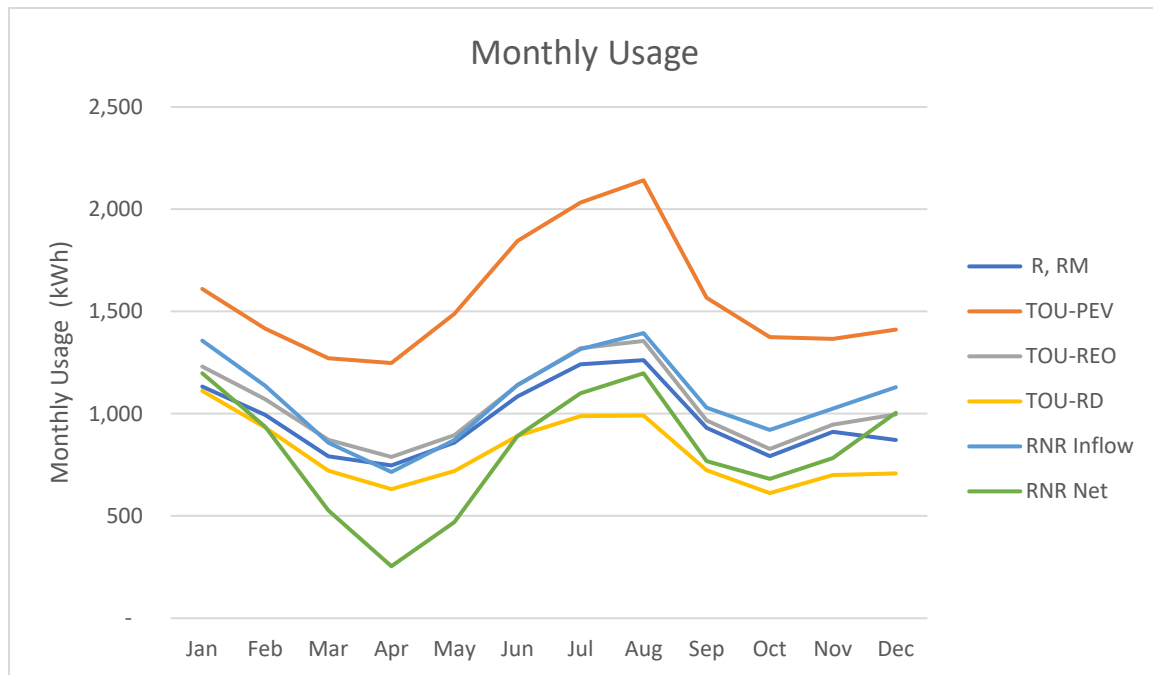


Figure 10 - Monthly Usage by Tariff

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.

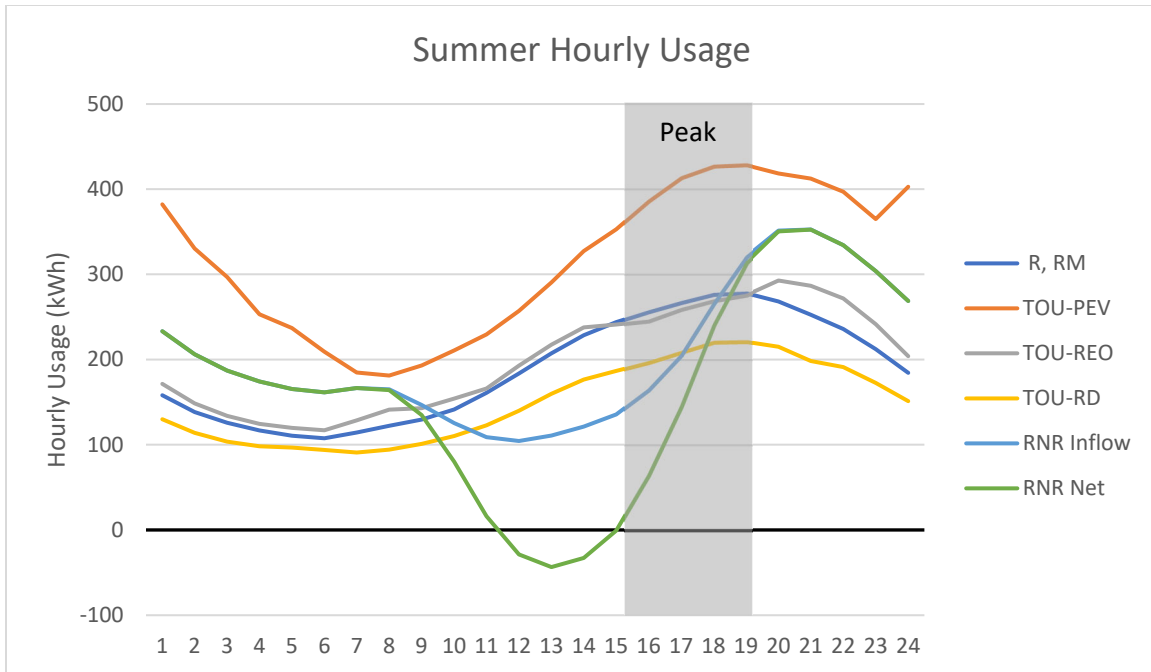


Figure 11 - Summer Hourly Usage by Tariff

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.

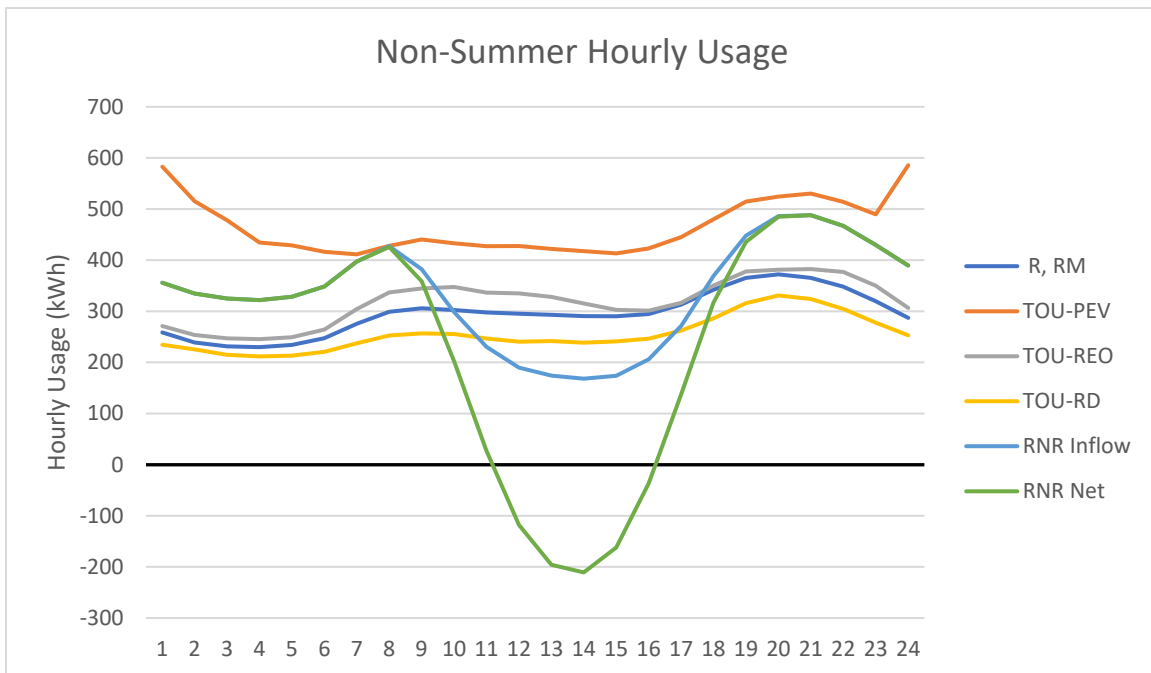


Figure 12 - Non-Summer Hourly Usage

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.

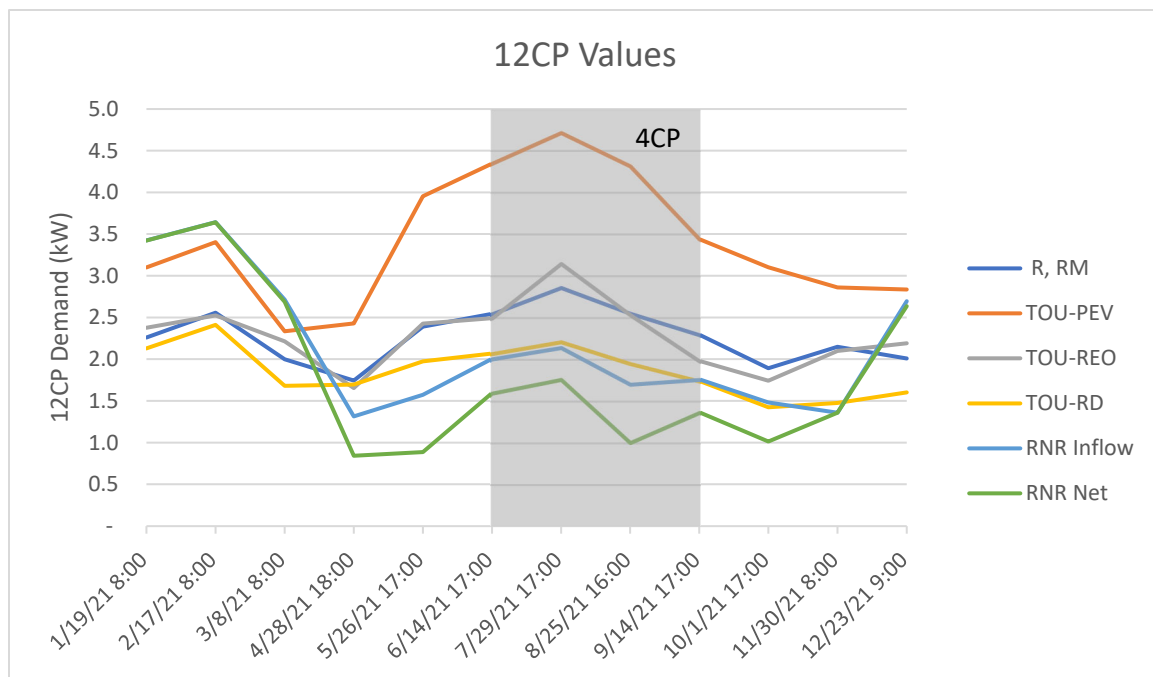


Figure 13 - 12CP Demand

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.

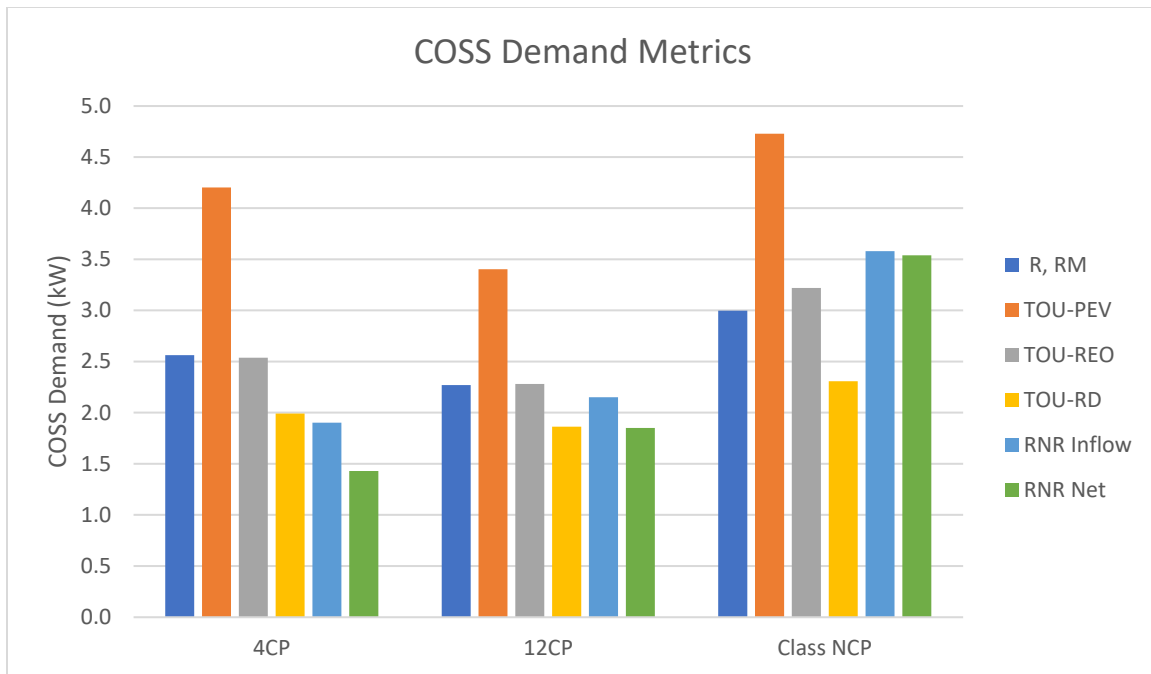


Figure 14 - COSS Demand Metrics

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.

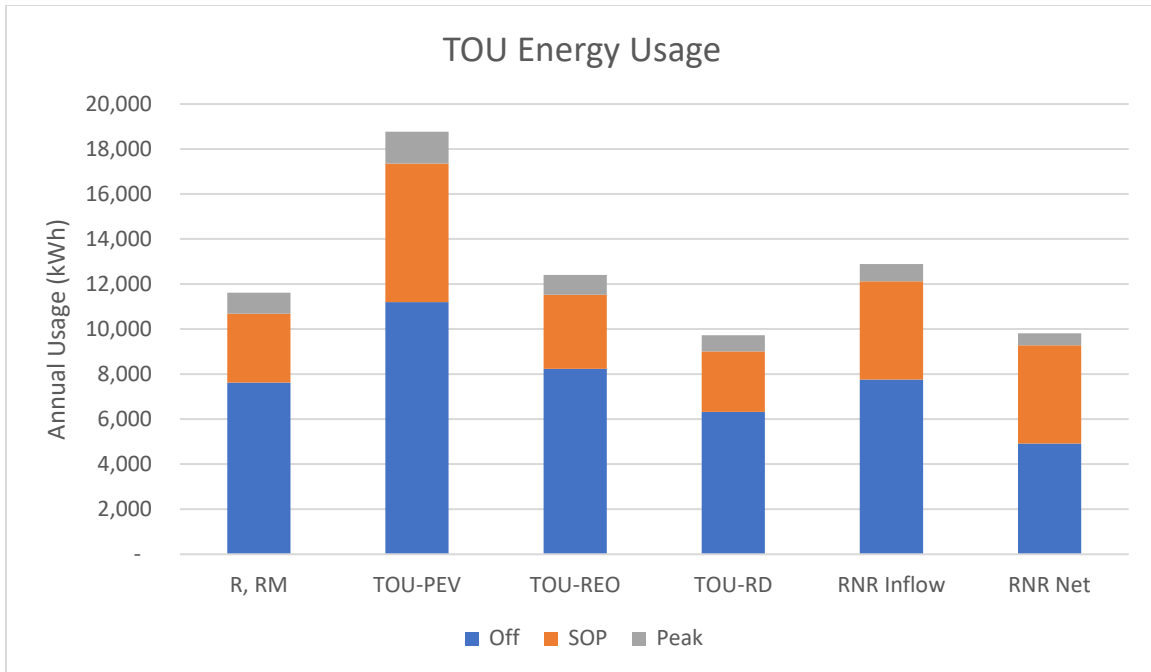


Figure 15 - TOU Energy Use by Period

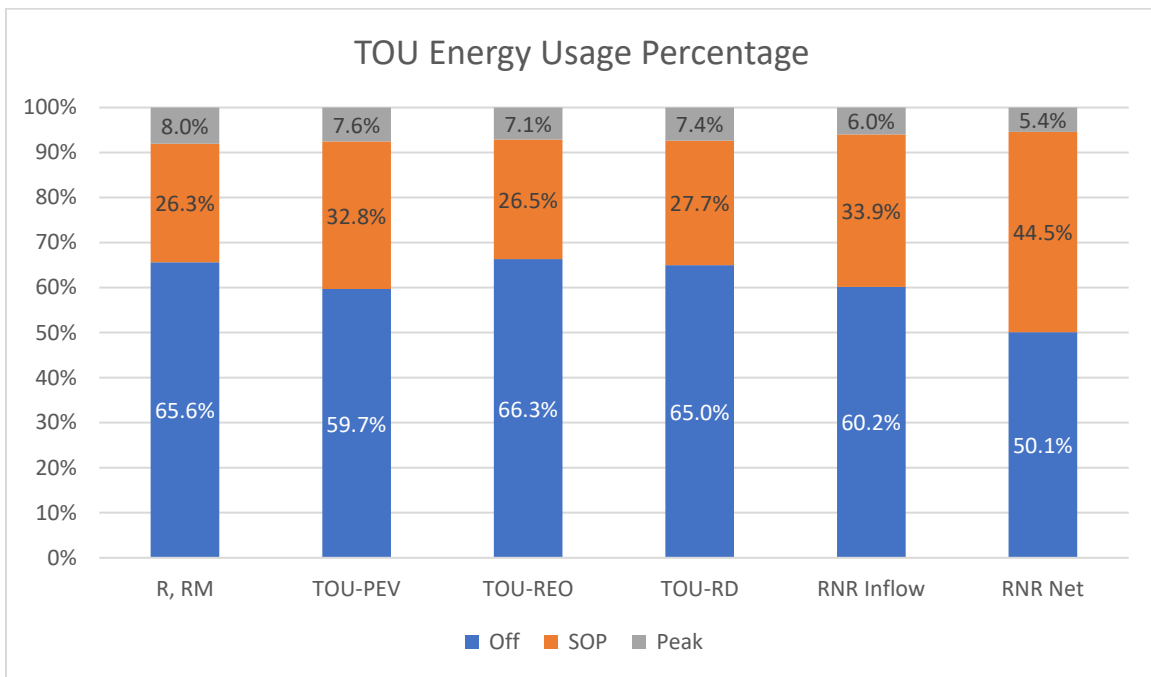


Figure 16 - TOU Energy Usage Percentage by Period

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),

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

6 **Q116. WHAT IS THE FINAL CHART YOU HAVE PREPARED?**

7 A116. The final chart in Figure 17 below shows the load factors using the COSS demand metrics.¹³²

8 Load factor relates the demand of a customer or customer group to its energy usage and can
9 be viewed as a measure of the efficiency of system usage. The higher the load factor, the
10 more consistently or “efficiently” a customer used the system.

11 As expected, the lower 4CP demand values coupled with higher energy consumption
12 causes the 4CP RNR Inflow and RNR Net load factors to climb substantially above all other
13 tariffs. The RNR customers approach a 4CP load factor of 80%, while the remaining tariffs
14 are in the 50-55% range. The increase on the 12CP is not quite as large, but RNR Inflow
15 customers still attain a 68% load factor, roughly 10% higher than the R group. The Class
16 NCP load factor is marginally lower for RNR Inflow customers, reflecting the higher demand
17 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 $LF = \text{Total Energy} / (\text{COSS Demand} * 8760)$

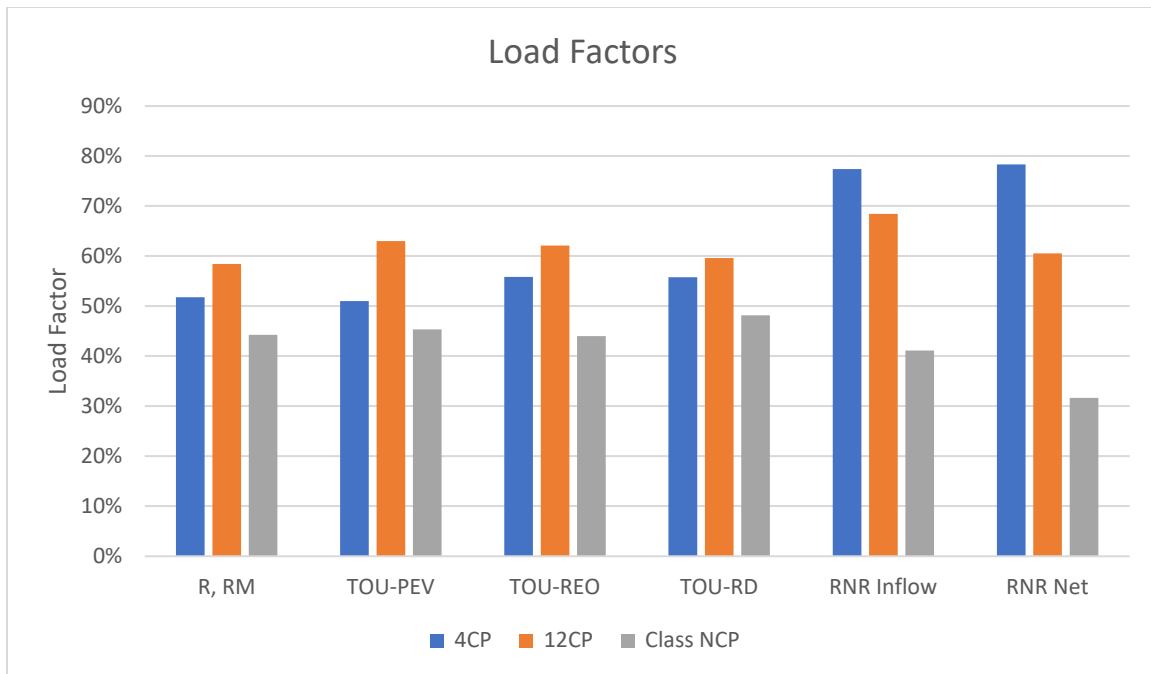


Figure 17 - Load Factors

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.

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.

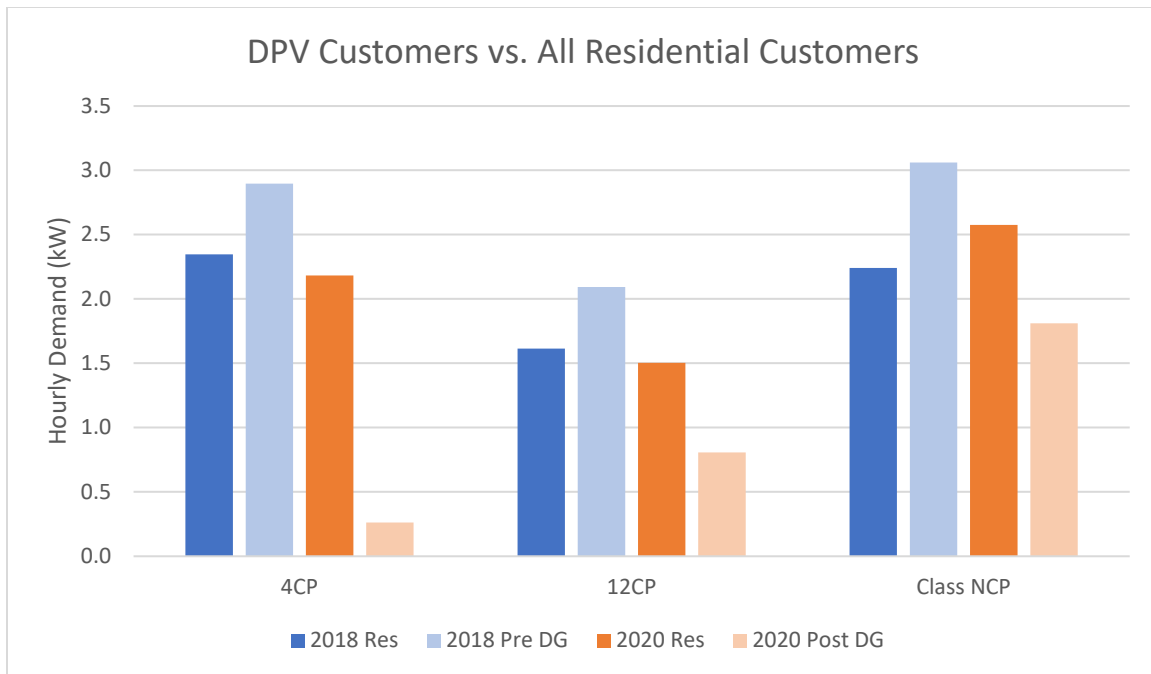


Figure 18 - DTE BTM PV COSS Analysis

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,

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

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

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

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

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

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

16 We aggregated data from the hourly outflows from 2019, 2020, and 2021 and broke
17 the data into summer and non-summer months.¹³⁴ Even though outflow is a function of both
18 solar generation and customer load, as seen below in Figure 19, the outflow shape closely
19 mirrors solar production. More than a third of outflow energy in the summer occurs during
20 the 2 PM to 7 PM hours that comprise the TOU peak period. Further, the average outflow
21 during these peak periods is 0.5 kW per residential customer. Multiplied by roughly 4,200
22 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.

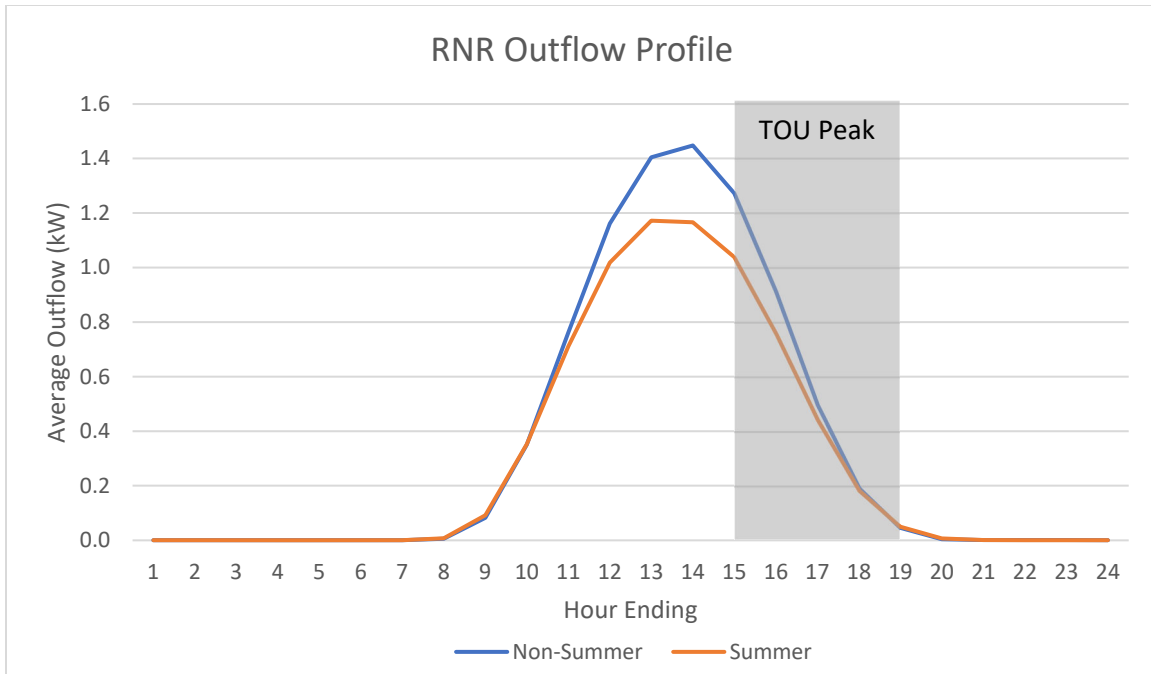


Figure 19 - RNR Outflow Profile

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.

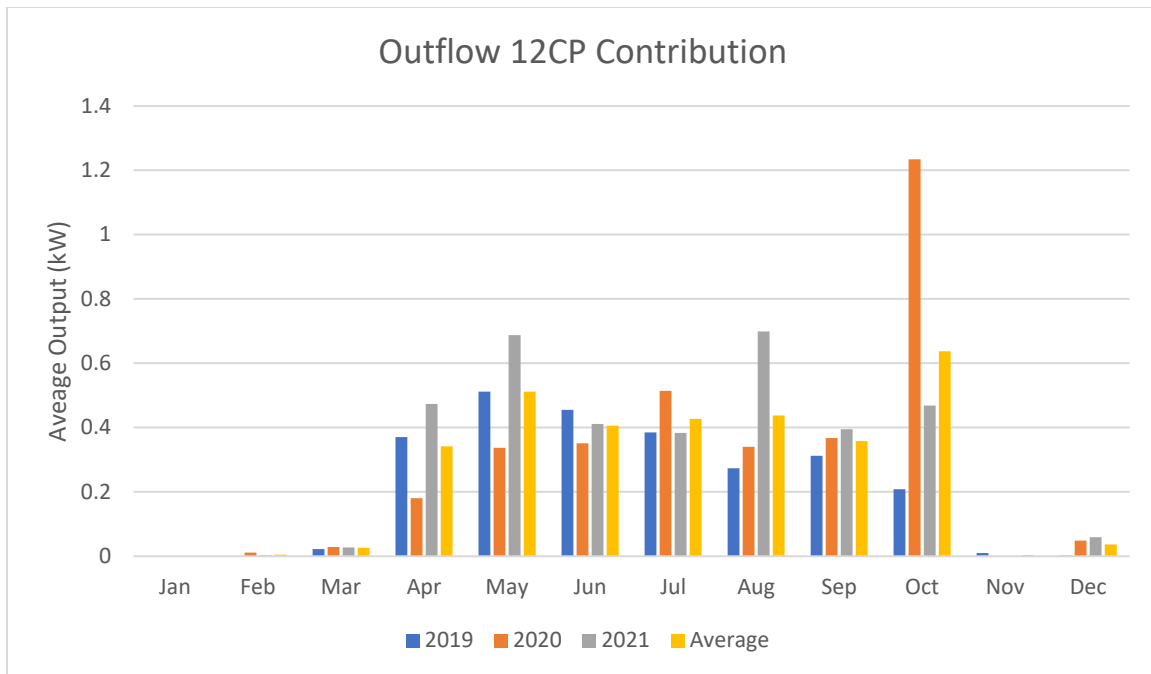


Figure 20 - Outflow 12CP Contribution

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

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

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

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

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

23 While this analysis was not as complete as we would have liked given the Company's
24 inability to furnish accurate data that was responsive to discovery, it still demonstrates the
25 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.

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

4 **Q127. DOES THIS CONCLUDE YOUR TESTIMONY?**

5 A127. Yes, it does.

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

Cumulative Residential Solar Capacity			Residential Solar Capacity per Capita			Single-Family Homes with Solar		
State	MW	Rank	State	W/Person	Rank	State	Percent	Rank
California	10,035.7	1	Hawaii	370.6	1	Hawaii	27.0%	1
Arizona	1,846.3	2	California	255.8	2	California	15.4%	2
Florida	1,359.5	3	Arizona	253.7	3	Nevada	9.4%	3
Texas	1,276.6	4	Nevada	219.3	4	Arizona	9.0%	4
New York	1,267.5	5	Connecticut	148.6	5	Washington DC	8.5%	5
New Jersey	1,245.5	6	Vermont	144.8	6	Massachusetts	7.3%	6
Massachusetts	989.8	7	Massachusetts	141.7	7	Connecticut	6.4%	7
Maryland	787.0	8	New Jersey	134.4	8	Utah	6.4%	8
Nevada	689.5	9	Washington DC	133.7	9	New Jersey	6.0%	9
Colorado	639.9	10	Maryland	127.7	10	Colorado	5.2%	10
Connecticut	535.7	11	Utah	126.4	11	New Mexico	5.0%	11
Hawaii	534.2	12	Puerto Rico	117.1	12	Puerto Rico	4.9%	12
Utah	421.9	13	New Mexico	112.4	13	Maryland	4.3%	13
Pennsylvania	383.9	14	Colorado	110.1	14	Rhode Island	4.3%	14
Puerto Rico	382.3	15	Rhode Island	81.1	15	New York	3.8%	15
Illinois	346.3	16	Delaware	75.1	16	Vermont	3.4%	16
North Carolina	280.9	17	New Hampshire	71.4	17	New Hampshire	2.3%	17
Washington	254.8	18	New York	63.9	18	Delaware	2.2%	18
South Carolina	254.6	19	Florida	62.4	19	Oregon	2.2%	19
Virginia	250.9	20	Idaho	50.9	20	Florida	2.0%	20
New Mexico	237.9	21	Oregon	50.7	21	Idaho	2.0%	21
Oregon	215.5	22	South Carolina	49.0	22	Texas	2.0%	22
Missouri	215.4	23	Maine	43.3	23	Missouri	1.5%	23
Louisiana	128.1	24	Texas	43.2	24	South Carolina	1.4%	24
Michigan	115.9	25	Missouri	34.9	25	Washington	1.3%	25
Ohio	101.1	26	Washington	32.9	26	Illinois	1.1%	26
New Hampshire	99.1	27	Pennsylvania	29.6	27	Louisiana	1.1%	27
Idaho	96.8	28	Virginia	29.0	28	Virginia	1.1%	28
Vermont	93.5	29	Louisiana	27.7	29	Pennsylvania	1.0%	29
Washington DC	89.6	30	Illinois	27.3	30	North Carolina	0.8%	30
Rhode Island	88.9	31	North Carolina	26.6	31	Alaska	0.7%	31
Minnesota	84.6	32	Arkansas	22.2	32	Maine	0.7%	32
Delaware	75.4	33	Montana	20.8	33	Wyoming	0.7%	33
Arkansas	67.1	34	Wyoming	20.5	34	Montana	0.6%	34
Indiana	65.7	35	Iowa	19.9	35	Arkansas	0.6%	35
Iowa	63.6	36	Alaska	16.6	36	Iowa	0.6%	36
Wisconsin	62.7	37	Minnesota	14.8	37	Minnesota	0.5%	37
Maine	59.3	38	Michigan	11.5	38	Wisconsin	0.5%	38
Georgia	53.6	39	Kansas	11.5	39	Michigan	0.4%	39
Kansas	33.8	40	Wisconsin	10.6	40	Ohio	0.3%	40
Oklahoma	33.5	41	Indiana	9.7	41	Kansas	0.3%	41
Kentucky	28.8	42	West Virginia	9.2	42	Oklahoma	0.3%	42
Montana	22.9	43	Ohio	8.6	43	Indiana	0.3%	43
Tennessee	17.2	44	Oklahoma	8.4	44	Georgia	0.2%	44
West Virginia	16.4	45	Nebraska	6.5	45	Kentucky	0.2%	45
Nebraska	12.8	46	Kentucky	6.4	46	Nebraska	0.2%	46
Alaska	12.2	47	Georgia	5.0	47	West Virginia	0.2%	47
Wyoming	11.9	48	Tennessee	2.5	48	Tennessee	0.1%	48
Mississippi	4.1	49	Mississippi	1.4	49	Mississippi	0.1%	49
Alabama	1.4	50	South Dakota	0.9	50	South Dakota	0.0%	50
South Dakota	0.8	51	North Dakota	0.7	51	North Dakota	0.0%	51
North Dakota	0.5	52	Alabama	0.3	52	Alabama	0.0%	52

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

1 BY MR. THOMASSON:

2 Q Have you prepared a summary of your testimony?

3 A (Witness Giese) Yes.

4 Q Would you please give that now?

5 A (Witness Giese) Sure thing.

6 MR. GIESE: Commissioners, thank you for
7 allowing me to speak on behalf of SEIA, Georgia SEIA,
8 and Vote Solar in this critically important matter.
9 The Commission has done a commendable job thus far of
10 bringing a comprehensive record in this proceeding,
11 as have many of the intervenors before you today. As
12 a solar industry professional with almost 10 years of
13 experience across 14 states, I am personally excited
14 to see how the industry will unfold in Georgia over
15 the next several years.

16 As a solar industry professional with almost
17 10 years of experience across 14 states, I'm
18 personally excited to see how the industry will
19 unfold in Georgia in the next seven years.

20 In my position at SEIA, I've had the unique
21 opportunity to participate or assist in a number of
22 residential solar regulatory proceedings across the
23 south. These include direct participation in the
24 Mississippi, North and South Carolina net metering
25 successor proceedings, and in assisting other

1 organizations develop rooftop solar policies in
2 Arkansas, Kentucky, Florida, Tennessee, and Virginia.

3 Prior to my work at SEIA, I worked in Hawaii
4 and on the west coast advising or directly
5 intervening in rooftop solar proceedings in states
6 with some of the highest rooftop solar penetration
7 rates in the country.

8 Like my colleagues, Mr. Lucas and Mr. Young, I
9 believe that these resources provide value to both
10 consumers and the utility, while providing primarily
11 locally grown economic opportunities across the
12 state. This is clearly the case in rooftop-heavy
13 states like Hawaii and California, but it is as
14 equally true in places like Florida, whose rooftop
15 solar industry supports more than 40,000 jobs
16 statewide, according to the local solar trade
17 association.

18 But we do not have to look to Hawaii or
19 California to know that these resources provide value
20 to both consumers and the broader utility grid.
21 There are a variety of program models that exist to
22 foster the sustainable and predictable growth of
23 rooftop solar, many of which are here in the south.

24 Arkansas, for instance -- and that's my home
25 state -- allows full retail net metering with

1 reasonable regulatory off-ramps to allow
2 re-examination of existing policies should the
3 utility company prove that there are unreasonable
4 cost shifts from solar adopters to nonparticipants.
5 Since 2019, no utility has been able to do so.

6 Virginia also allows for full retail net
7 metering and encourages the utility to seek some
8 amount of rooftop solar generation every year through
9 its distributed generation carve-out.

10 In South Carolina, the Commission has examined
11 two different types of solar programs beyond flat net
12 metering. A one-to-one time-bearing-based tariff in
13 Dominion service territory and a flat rate net
14 metering tariff with a demand-response
15 incentive-induced territory called the Smart Saver
16 program, which Mr. Barnes, I believe, referenced
17 earlier.

18 The aforementioned time-bearing tariff allows
19 appropriate compensation for a customer-sided
20 resource at times when that energy is most valuable,
21 while a future iteration of the Smart Saver program
22 will hopefully provide participants price signals to
23 adopt grid-beneficial technology, such as energy
24 storage and advanced inverter functionality.

25 After five years, Mississippi reopened its

1 rooftop solar proceeding earlier this year -- or last
2 year and concluded that proceeding earlier this year
3 by adding a first in the nation low-, middle-income
4 direct cash rebate for residents looking to install
5 solar and expanded the low-, middle-income rate adder
6 to individuals at 225 percent of the poverty line and
7 below.

8 Finally, last year's rate case in Kentucky
9 Power Service territory created a novel, multi-part
10 credit structure for rooftop solar resources that
11 include a variety of compensation rates for several
12 different capacity services that the Commission
13 concluded that rooftop solar provides, such as
14 generation, transmission and distribution capacity,
15 as well as other ancillary services.

16 The point of all of this is that there are many
17 potential paths of reaching the same goals; the goals
18 of consumer choice, resource diversity and economic
19 development.

20 The company consistently claims that, in its
21 very narrow view, the current slate of rooftop solar
22 installations across the service territory per its
23 revenue, to the tune of 20 cents per person per year,
24 and they recommend that the only sensible course of
25 action is to create a program structure that will

1 conveniently result in very little customer adoption
2 of rooftop solar resources.

3 Like my colleagues, I ask for the Commission's
4 support in expanding the RNR tariff to provide
5 Georgia's electric consumers with choice, resiliency
6 and economic opportunity. I also challenge the
7 Commission to question how the company reaches these
8 conclusions when so many of their counterparts and
9 commissions in states across the south don't appear
10 to be doing the same.

11 Again, thank you for allowing me the
12 opportunity to participate in this critical matter.

13 MR. LUCAS: Thank you for that.

14 And, Commissioners, before I start my end of
15 the summary, I did find that typo that I referenced
16 earlier. It is on page 65, line 20, what currently
17 reads: What is your recommendation on the company's
18 interconnection fee proposal?

19 It should read: What is your recommendation on
20 the company's RNR monthly program proposal?

21 Thank you, Madam Chair and Commissioners. Good
22 to see you guys again. I hope you had an enjoyable
23 and restful Thanksgiving break.

24 As Will set up in our -- the first part of our
25 summary, laying the stage for what's happening in the

1 broader context of net metering discussions, I would
2 like to highlight a couple elements of our testimony
3 that we put in just to bring out a few of the
4 specific points that we talked about and have had
5 some discussion previously before.

6 The three things I'd like to talk about first
7 are about information that you, the Commission, asked
8 for from the company, which the company failed to
9 provide to you.

10 The second is about the earnings band. And I
11 will touch lightly on that because I know we've
12 talked quite a bit on that, as well.

13 And third is a summary of the analysis that we
14 were able to do with the limited information that the
15 company provided.

16 So in the first instance, among other things,
17 you, the Commission, asked for two specific elements
18 from the company in this case. The first was a
19 report on the TOU-RD rate and how it was working as
20 the default rate service.

21 As we heard yesterday from the company's
22 witnesses, they didn't do the report. They just did
23 not do the report, despite you asking for it, despite
24 them filing four rounds of testimony in this
25 proceeding.

1 So into that void, a number of other
2 intervenors, including ourselves, did do some
3 analysis on that rate. And what we found and
4 discussed, again, extensively in the last round of
5 these hearings, is that that rate is poorly designed.
6 It's not cost reflective. It's not easily
7 understandable for customers and it should not be the
8 default rate.

9 Unfortunately, instead of addressing those in a
10 report for you, the company is now doubling down on
11 that recommendation and actually proposes to make the
12 TOU-RD rate the mandatory rate for new RNR
13 residential customers.

14 For all the reasons that we explained before,
15 this is not a rate that should be the default rate
16 for anyone, much less a mandatory rate for solar
17 customers. And we would respectfully request that
18 you reject the company's proposal on that particular
19 element.

20 The second piece of information that was
21 requested from the company was cost-based data so
22 that all parties could provide, test and challenge
23 the cost-based data in this case. Well, obviously,
24 Georgia Power is the only party who can provide the
25 cost-based data from their own system. It's up to

1 other parties, such as ourselves, to test and
2 challenge that.

3 So when staff asked a very broad set of
4 discovery on this, they basically asked for hourly
5 information for all the RNR customers for several
6 years and a corresponding file that had system
7 information, including when the system was installed
8 and how large it was, that would have enabled parties
9 to analyze, test and challenge some of these
10 cost-based data.

11 Unfortunately, the first version of the work
12 papers the company presented back contained an error.
13 Basically, we're not able to reconcile the systems
14 between one file and another.

15 The company did correct that, but it turned out
16 that the information they provided was both
17 incomplete and not what was actually requested. So
18 rather than providing a data set of all the RNR
19 customers, they provided only a subset of customers
20 which they had used for their own analysis.

21 And rather than providing when the system was
22 installed, which is critical to be able to analyze
23 customer performance before and after solar, they
24 gave us a date on when the system was added to the
25 RNR tariff. Those are two very different numbers,

1 two very different dates.

2 And it meant that we were not able to do the
3 type of analysis that we had hoped to do with this
4 information. And despite the company being aware of
5 these shortfalls, on Thursday night at 10:30, the day
6 before testimony was due, they responded back to us
7 and said: We gave you what we gave you. We think
8 it's responsive. We understand these are not the
9 things that you asked for, but this is what you have
10 for this analysis.

11 So we were unable to complete that analysis and
12 improve the record on that point.

13 The second thing that I would like to talk
14 about is the earnings mechanism, the \$1.4 million we
15 talked about. And, again, this has been covered
16 extensively in this hearing. But one element that I
17 would like to add is a piece of discovery that came
18 from the company in between the two hearings.

19 They were asked whether they considered how
20 this \$1.4 million would be impacted by the earnings
21 band mechanism that is currently in place. And their
22 answer was basically it's not impacted.

23 So from the position of the company, even
24 though they have consistently earned above the ROE
25 set point for the last 11 years, as I showed in the

1 first round of testimony, and even though they
2 collected \$258 million more in 2021 than rates based
3 on their ROE set point, they still believe that they
4 are entitled to the \$1.4 million of additional money.

5 All that would do, if that was approved by this
6 Commission, would increase the revenue overcollection
7 by \$1.4 million, from 258 million to 259.4 million.

8 The company went as far to say that any revenue
9 erosion from any group of customers by appropriate
10 rate-making principles must be recovered,
11 notwithstanding the actual reality on the ground of
12 the company consistently having surplus revenue.

13 So, again, we would reiterate our request in
14 the previous round, that that \$1.4 million be
15 recognized for what it is -- not a cost shift, but a
16 revenue erosion -- and that you deny the addition of
17 that to the revenue requirement.

18 And, lastly, I would like to summarize the
19 analysis that we were able to provide with the
20 limited information that was provided by the company.
21 We were able to put together a sample of RNR
22 customers and non-RNR customers. And in this
23 analysis we compared customers on each tariff.

24 So we looked at customers on the R tariff, the
25 nights and weekend, the PV, plug-in electric vehicle

1 tariff, and the RD tariff, and compared them in their
2 key usage metric for customers who have solar. And
3 we were only able to do this for one year and we were
4 only able to do it for a subset of customers because
5 of what was provided for from the company.

6 But what we found is that customers who have
7 solar, who are in the RNR program, use less energy
8 on-peak. They use more energy during low-cost
9 overnight, super off-peak hours. They have lower
10 cost of service metrics for the 4 CP and the 12 CP
11 metrics, which drive production and transmission
12 costs.

13 These are all the characteristics that you
14 would want for lower-cost customers. And what we
15 feel our analysis shows is that the RNR customers are
16 actually lower in cost to serve than the typical
17 customers on the other rates.

18 When you actually add in the outflow energy --
19 this is just on the inflow. That's not what they use
20 from the company.

21 When you add the energy that they put onto the
22 system, which simply flows to their neighbor and is
23 consumed by their neighbor, those metrics improve
24 even further. So despite the fact that we weren't
25 able to do all of the analyses that we had hoped to

1 be able to do, we were able to show that RNR
2 customers have better cost metrics across the board
3 than do non-RNR customers. And we think that helps
4 support our position that the monthly netting program
5 be extended at the full retail rate.

6 Thank you for your time. We look forward to
7 your questions.

8 MADAM CHAIR PRIDEMORE: Any other summaries?

9 MR. YOUNG: No, ma'am.

10 MADAM CHAIR PRIDEMORE: Okay. Questions from
11 Commissioners.

12 VICE-CHAIRMAN ECHOLS: I have a couple of
13 questions, Madam Chair.

14 MADAM CHAIR PRIDEMORE: Go ahead, Commissioner.

15 VICE-CHAIRMAN ECHOLS: This study that you were
16 just talking about, it sounds like that RNR is a
17 tutor to teach customers to be better energy users
18 and that the results of, I guess, the schooling or
19 the lesson that they get by experiencing this and
20 looking at their phone and seeing what their panels
21 are doing and shifting this and shifting that, that
22 this actually winds up benefiting everyone, including
23 low-income ratepayers or anyone -- anyone on the
24 system.

25 Is that what you're saying?

1 MR. LUCAS: I think so. But I would say it's
2 not even that they have to do anything about it.

3 I think your camera is here. Pardon me. I
4 think that's where I'm looking at you.

5 Basically, by the fact that these systems
6 exist, the solar production that is occurring means
7 that these customers will use less of the system --
8 the company system and will reduce stress on the grid
9 during those key times.

10 And that benefit does accrue more broadly. So,
11 yes, it is something that when you put solar in,
12 you're able to reduce the stress during key hours.
13 That has a benefit to all customers by allowing those
14 -- the solar customers to use the system more
15 efficiently.

16 VICE-CHAIRMAN ECHOLS: You heard yesterday
17 Georgia Power reference this concept as a wolf;
18 right?

19 A wolf coming. And I -- I mean, it really
20 sounds more like a Labrador Retriever to me in the
21 sense that what we're doing -- what we're doing with
22 these customers -- and we know that many of them wind
23 up getting electric cars, many of them wind up going
24 on time-of-use, you know, type of rate, charging cars
25 overnight, helping the grid.

1 It just seems like -- it seems like that the
2 way we're doing it in Georgia, which is different
3 than California, it's different than Arizona, Nevada
4 or any other state, that the way we -- the way that
5 we kind of eased into net metering by -- by creating
6 a kiddie pool.

7 We created a kiddie pool with 5,000 in 2019.
8 I'm not for just throwing, you know, our state into
9 the deep end of the pool where the swimming wolves
10 are. I'm not trying to do that.

11 I would -- I would settle for 75,000, 30,000,
12 25,000, 20,000. Let's just -- let's just keep
13 experimenting with this in the Georgia way, not going
14 crazy, not, you know, opening the door for
15 everything. I know some of y'all probably want --
16 you know, you probably wanted unlimited.

17 But is there any -- this is a question. Is
18 there any, you know, value to us doing what I'm
19 suggesting; that we go -- move from the kiddie pool,
20 now to the shallow end, and add 20,000 or 30,000?

21 What do you think about that?

22 MR. YOUNG: Commissioner, I appreciate those
23 words. And, yes, I had some time to reflect last
24 night on Mr. Marzo's -- I think non-malicious
25 mischaracterization of the solar industry as wolves.

1 And, you know, I thought about what is our role
2 in this little story; right? And I think the reality
3 is, you know, Georgia solar companies, like Velo or
4 Creative that you heard from, and some of their
5 customers earlier this morning, or ADS, you know,
6 really we're the three little pigs in this story.

7 We're just here trying to build, you know, more
8 efficient, little solar houses and businesses across
9 the state. And help Georgians, as you said, learn to
10 use their energy better and more wisely.

11 And, you know, we hear this sort of big bad
12 wolf huffing and puffing about, you know, cost
13 shifting and revenue erosion and monthly netting,
14 trying to blow our little houses down; right?

15 And, you know, reality is we're not trying to
16 tear the wolf's house down to build our own; right?
17 There's plenty of wood in the forest. We can build
18 our own houses. And I think that we just want a
19 little part of the neighborhood without the fear of
20 the big bad wolf.

21 And so we sit here before you today, you know,
22 just asking for, you know, a fair price for our eggs;
23 right? And I think as you so rightly acknowledged
24 yesterday, as the company has, in previous
25 proceedings, been pushed to invest in DG solar and

1 create a market, that we would like to see a similar,
2 reasonable investment to grow the kiddie pool.

3 So if we could take that 1.4 million out of
4 1.4 billion and convert that into \$100 million that
5 is going into Georgia communities by Georgians to
6 also improve resiliency, to decarbonize homes and
7 businesses, and to create new jobs, I think that's a
8 win-win for everybody.

9 And so, yes, we would say, please, help us go
10 on a thoughtful path of increasing monthly netting in
11 a very similar way that we've done in other areas of
12 DG solar on the grid so that we can move, as the
13 Chairwoman rightly indicated, almost fourth in the
14 nation on total solar on the grid.

15 You know, we're currently 44th or 42nd in
16 behind the meter. We'd like to be in the top ten, as
17 well; right?

18 Georgia wins when the Bulldogs and the
19 Bumblebees are both in the top ten. So I think
20 there's some room for both of us in this space. So
21 thank you for your question.

22 VICE-CHAIRMAN ECHOLS: One more question about
23 the TOU-RD. I don't know if you all heard me
24 yesterday asking about the Tempo unit or the Sense
25 unit that Mr. Legg was talking about. Some kind of

1 signal, right, that would help these customers not be
2 in the dark.

3 So to think about what is happening, having to
4 look at the website after the fact to see if they
5 have gone into, you know, the red zone, you know, on
6 the RPM meter, do either of you guys or any of you
7 guys on the panel have experience with this?

8 Is it unreasonable for me to ask the company to
9 stand up some kind of signaling and hold off on
10 making this a mandatory rate?

11 MR. LUCAS: Thank you, Commissioner, for that.

12 The first is, with respect specifically to the
13 TOU-RD rate, remember that there's two different
14 elements to that. There's the noncoincident
15 peak-demand charge, which is based on your highest
16 hour out of any of the roughly 740 hours in the
17 month. And then there is the volumetric energy-based
18 time-of-use rate.

19 One of the company's witnesses, I believe,
20 yesterday mentioned that the energy rate continues to
21 provide a price signal similar to what you're
22 describing. In fact, though, the energy rate for the
23 TOU-RD has a smaller differential than do the night
24 and weekends and the PEV rates.

25 So when you actually add fuel to the rate

1 differential, the peak to off-peak difference is
2 about 10 cents on the TOU-RD rate. It's actually
3 about 13 to 15 cents on the nights and weekends rate
4 and the PEV-TOU. So the one price signal that that
5 rate is capable of sending is actually weaker than
6 the volumetric time-of-use rates.

7 And then, secondly, there is no way to send a
8 price signal towards the demand portion of that
9 charge. It's based on the single highest hour. So
10 the second that you hit that in a month, you've
11 locked it in for the rest of the month. There's no
12 incentive for you to hold down your usage to reduce
13 that demand component.

14 And, also, unless you are vigilant in the 740
15 or so hours of every single month, you run the risk
16 of having one high anomalous hour spike your usage
17 for that and lock in a very high bill.

18 So, with respect, our view is that the RD rate
19 as it's currently designed is just not conducive. It
20 shouldn't be the default rate.

21 It doesn't send good price signals. The nights
22 and weekends and plug in electric vehicle time-of-use
23 rates they have are better. And those are rates that
24 we think should be encouraged, as opposed to the
25 three-part demand charge rate.

1 VICE-CHAIRMAN ECHOLS: Thank you so much.

2 MR. YOUNG: And I think it would be a great
3 welcome gift to new customers for Georgia Power to
4 give them a Sense monitor with their system as they
5 sign on to the RNR tariff.

6 VICE-CHAIRMAN ECHOLS: I do think if we did
7 that, that it would pay for itself. Because if they
8 get the text messages and see: Oh, I'm about to hit
9 that and they curtail, you know, and decide not to,
10 you know, do their -- you know, dry their clothes or
11 start the dishwasher, they're going to benefit the
12 system more than likely.

13 So I do think we eventually would get our money
14 back on that. It would be interesting to see how
15 long it would take. Maybe one summer season or two.
16 I'm not sure.

17 Thank you.

18 MR. YOUNG: And I think it would give us the
19 granular data that we need to provide for the company
20 to do the cost of service study that we requested and
21 staff requested earlier in this proceeding. And then
22 in three years we can revisit it with that new
23 granular Sense data and see where we are.

24 VICE-CHAIRMAN ECHOLS: Thank you.

25 COMMISSONER MCDONALD: Mr. Young, how many of

1 these states that you highlight, like on your charts
2 here with -- in the blue, jumped into a rooftop solar
3 program and have hiccups and had to back up and
4 regroup and move up again?

5 Has any of that happened in that?

6 I go back to the original utility-scale solar
7 in Georgia where the Chairperson talked about earlier
8 today that we didn't just go out there and cover the
9 world. Even a lot of the solar developers wanted
10 2,000, 3,000 megawatts right off the bat.

11 We didn't do it that way. In Georgia, we
12 progressed, but we've never had to back up.

13 MR. YOUNG: Yes.

14 COMMISSONER MCDONALD: We've gone forward and
15 forward, forward and reached the ranks in that. Is
16 there a correlation between rooftop solar and our
17 program, the utility solar, that we might ought to
18 kind of track and follow?

19 MR. YOUNG: Yeah. And I think -- absolutely,
20 Commissioner. I mean, I think what we're talking
21 about is a similar thoughtful measured progression
22 like you led on the DG side in other areas of solar.
23 Applying that same methodology and approach to behind
24 the meter.

25 And I think you're right. It would avoid

1 potentially some of the hiccups that some other
2 states have encountered. And as other intervenors
3 have said, you know, there's a lot of ground between
4 where we are today and even some of our neighboring
5 southeast states, as far as the level of penetration.

6 So in the next hearing in three years, you
7 know, we would have time to revisit it again and
8 continue to be thoughtful in the way we grow it. So
9 we're not asking for, you know, an opening of the
10 flood gates, as they say, but just a thoughtful
11 increase in what we can do.

12 So that there's stability in the market; right?
13 So that the right signals can be given to thoughtful
14 companies that are based in the state to provide the
15 proper marketing and consumer engagement to build
16 these systems so that they are -- they do last and
17 they deliver the return on investment that the
18 customers who are installing them are expecting, as
19 well.

20 COMMISSONER MCDONALD: I like your focus on
21 thoughtful companies.

22 MR. GIESE: Can I --

23 MR. YOUNG: Thank you.

24 COMMISSONER MCDONALD: We don't want the
25 renegades.

1 MR. YOUNG: That's right.

2 MR. GIESE: Can I add something quick to that?

3 COMMISSONER MCDONALD: Yes, please.

4 MR. GIESE: In response to your question, I
5 assume you're referencing this chart, Exhibit 13.

6 COMMISSONER MCDONALD: I am.

7 MR. GIESE: So one thing that strikes me as
8 missing, I think, a little bit from this
9 conversation, and that some of these highlighted
10 states have looked at, especially in the Carolinas,
11 which I'm involved in the North Carolina proceeding
12 and was involved in the South Carolina proceedings,
13 is -- you know, they look at one side, which I think
14 we've covered a lot in here, the revenue erosion
15 piece. But there's another side, which is the
16 benefits piece; right?

17 South Carolina is a very good example of this
18 where in that instance, especially in Duke service
19 territory, you actually had a collaboration between
20 the utility and stakeholders, such as solar
21 companies, that banded together to create a
22 sustainable tariff that provided benefits to the grid
23 in the form of solar energy, but also in the form of
24 novel rate design and demand-responsive devices.

25 In that case, earlier this year it took the

1 form of a smart thermostat, paired with a solar
2 installation, but could feasibly take the form of a
3 variety of other different types of grid services
4 that these systems provide; right?

5 So your point earlier with another testifies
6 is -- and I think you hit the nail on the head, which
7 is that, ultimately -- I mean, it is a policy
8 decision; right?

9 And I think you have the decision to make a --
10 do you just want to stop or -- and leave,
11 essentially, in my view, money on the table for these
12 DER systems that could provide some type of service
13 to the grid, to customers, to their neighbors, to the
14 utility, by expanding this program and iterating that
15 program, or do you just want to cut it off at its
16 head and deal with whatever implications that would
17 be?

18 Because, remember, these 5,000 systems weren't
19 just for those 5,000 customers. They were for the
20 jobs that were built in the industry that was built
21 around to create those 5,000 systems; yes?

22 So I think that's another kind of point
23 inherent in this question that you're dealing with,
24 which is: How do we view these DER systems
25 holistically?

1 COMMISSONER MCDONALD: Well, you drew analysis
2 with Duke and North Carolina or South Carolina. And
3 our program -- in the solar program we've had going
4 on in Georgia, Georgia Power Company been a great
5 partner in it.

6 We've bumped heads, yes. But in the process
7 we've had a program that has been, by record facts,
8 showed success.

9 MR. GIESE: And it's not unreasonable to have
10 disagreements on matters of policy, but I think
11 it's -- I think for some of these states that we're
12 highlighting, we've shown that, at least in my
13 experience, a collaborative process has led to
14 greater benefits overall for both solar energy, which
15 I represent, and the utility itself and the consumer
16 ultimately.

17 MR. YOUNG: And I think, as we mentioned
18 earlier in testimony, you know, right categorizing
19 these resources as DER resources that have a value
20 both to the owner of that resource and to the company
21 creates a path for that collaboration. And
22 presenting right price signal and seeing how
23 customers react and then adjusting rates and tariffs
24 and other programs based on -- on that data.

25 You know, we have a little bit of data. I

1 think we could see more data and we could make even
2 better decisions as the -- this process progresses
3 for sure.

4 MADAM CHAIR PRIDEMORE: Any other questions
5 from Commissioners?

6 COMMISSIONER SHAW: I do.

7 MADAM CHAIR PRIDEMORE: Commissioner Shaw.

8 COMMISSIONER SHAW: Thank you.

9 You know, as we move towards what's likely to
10 be a policy decision, I can't help but think about
11 what the impacts are from the Inflation Reduction
12 Act, or I'll say from IRA here on out.

13 And I know -- I've talked to numerous groups on
14 each side of the issue on those impacts. And I think
15 there's still some uncertainty, as far as what those
16 impacts are. But that weighs heavy on me in terms of
17 trying to determine and have some idea of how those
18 impacts will affect this program.

19 This -- these programs going forward, and what
20 I mean by that is how the effect and the impacts from
21 some of the newer changes as a result of the IRA,
22 such as the new tax credit on battery storage,
23 which -- correct me if I'm wrong, but that will be
24 something new; correct?

25 MR. LUCAS: For standalone storage systems,

1 that's correct.

2 MR. GIESE: That's right.

3 COMMISSIONER SHAW: So I would just like
4 someone, regardless whoever you all feel is best
5 or -- give me an idea of how you think that that will
6 impact the growth of this industry in Georgia going
7 forward.

8 MADAM CHAIR PRIDEMORE: I want to give you all
9 the opportunity to answer that question, but I'm
10 going to let the room know that we're taking our
11 lunch break in exactly five minutes.

12 So if you can answer it in five, great. If
13 not, then come back. You can all three answer it and
14 we'll do it after lunch.

15 MR. LUCAS: Great. Thank you for that.

16 I'll answer first and then you can maybe turn
17 it to the other folks. There are definitely going to
18 be some big game changers in that.

19 A standalone storage ITC you mentioned has the
20 potential to be impactful probably more so for larger
21 systems, whether it's, you know, front-of-the-meter
22 storage or larger commercial systems.

23 The storage was already eligible for the ITC if
24 it was paired with a solar system. So that had
25 previously existed. Solar-plus storage systems could

1 capture the 30 percent for the whole piece.

2 A number of the other provisions that were
3 added beneficial are going to be beneficial on the
4 utility-scale side. So the ability for companies to
5 elect the production tax credit, instead of the
6 investment tax credit may be more beneficial for
7 larger-scale projects.

8 It's unlikely that that particular provision is
9 going to be selected by smaller residential customers
10 simply because of the way the economics play out.

11 And, likewise, there are some provisions that
12 have bonuses or adders to the ITC. But, again, those
13 are applicable largely to systems that are one
14 megawatt and over.

15 So we're not talking about residential systems.
16 It is conceivable that some of the distributed
17 generations that Georgia Power has here, where you're
18 looking at those 3- to 5-megawatt programs, could be
19 beneficial -- benefit specifically by those changes.

20 But it is not going to be as pronounced in the
21 residential or the small commercial rooftop sector.

22 Did I forget anything?

23 MR. GIESE: No. I think that answered it
24 pretty well.

25 I mean, it -- I think from SEIA's perspective

1 nationally, the IRA is going to produce a lot of
2 different impacts, most of which I think will be
3 positive to the whole industry.

4 I think the question here is that, like, if --
5 if the Commission decides not to continue some type
6 of RNR program as we've described, right, or
7 something that would build or continue building
8 distributed generation, I don't know, I guess, under
9 an instantaneous netting RNR-style program whether
10 any amount, I think, of benefit in the IRA would
11 produce a significant industry here in Georgia.

12 MR. LUCAS: And I think just to follow up on
13 that -- and I think this was discussed before. The
14 ITC was extended. It was obviously locked in for ten
15 period -- ten years.

16 There is a value associated with that
17 certainty. But it never dropped below 26 percent for
18 residential customers. There's just one year where
19 it was 26 percent and now it's back up to 30 percent.

20 And it had been 30 percent for most of the last
21 decade. So there is an incremental benefit,
22 certainly, from going from 26 to 30. But it isn't a
23 game changer where it went from nothing to 30 or
24 where it is a newly created tax credit.

25 And the another thing that, unfortunately,

1 we've been challenged with and we've heard it here,
2 is prices are up. Those include prices for solar
3 panels. They include prices for things like metal,
4 labor, et cetera.

5 So the IRA will certainly help. We're
6 extremely excited about the potential for domestic
7 manufacturing and the ability to bring more of that
8 onshore and produce, you know, USA made content
9 that's going to be a necessity for some of these
10 bonus adders.

11 But there -- in the short term, there are some
12 price challenges associated with that, as well. Not
13 the least of which is increasing interest rates on
14 financing.

15 So, yes, the IRA will help. In the short term,
16 there's some headwinds that the industry is trying to
17 work through. I look forward to the next decade of
18 really being able to expand the domestic market and
19 see the IRA impact, you know, sectors large and
20 small.

21 COMMISSIONER SHAW: Okay. Thank you.

22 Would you say that the IRA will impact the
23 percentage of new rooftop customers that will also
24 have battery storage?

25 MR. LUCAS: Potentially. But, again, I

1 don't -- the battery -- solar plus storage was
2 already eligible for the ITC prior to the IRA.

3 So systems that were designed where the battery
4 charges from the solar system, which is the way --

5 COMMISSIONER SHAW: Would you say that the
6 majority of the new customers that are rooftop
7 customers do have battery storage?

8 MR. LUCAS: I don't think the majority do.
9 That's going to be a regional difference. In certain
10 places, like Hawaii, for example, that --

11 COMMISSIONER SHAW: I'm just talking about
12 Georgia.

13 MR. LUCAS: In Georgia I don't know the
14 specifics of residential. There are benefits of
15 adding storage to your system. There are incremental
16 costs, as well. And that would be a question on the
17 economics of that individual customer.

18 It's different for residential customers than
19 it is for commercial customers. So all those things
20 will factor into that calculation.

21 But the IRA specifically doesn't change the tax
22 credit that could impact that decision.

23 COMMISSIONER SHAW: The reason why I'm focusing
24 on the battery storage is because I've heard it said
25 in the past, outside of the proceeding, that as more

1 customers do have battery storage, so they are able
2 to use more of their own generation, so less is going
3 back into the grid. Do you feel like as that number
4 increases and more of the generation is being used by
5 the -- by that customer, that this whole argument
6 about net metering is going to be less important, I
7 guess you would say?

8 Not less important, but not as much in the
9 forefront when you've got -- I guess what I'm asking
10 is: Do you think that the fact that more people will
11 be using their own energy they're generating will
12 make this issue less -- less of a focus?

13 MR. LUCAS: No. I understand. I appreciate
14 the question.

15 I think on the margins that may be true. I
16 don't think it's the case in the industry overnight.
17 It's going to go -- sorry, Chair.

18 MADAM CHAIR PRIDEMORE: It's lunch break.
19 We're adjourned until 2:00.

20 (A recess was held from 12:56 p.m. until 2:01 p.m.)

21 MADAM CHAIR PRIDEMORE: Okay. We are back on
22 the record.

23 I believe the last item before the break is you
24 were answering a question from Commissioner Shaw.

25 Commissioner Shaw, if you would like to restate

1 your question, if it wasn't fully answered.

2 COMMISSONER SHAW: Well, I'll restate it. But
3 you may have already answered it. And if you think
4 you fully answered it, I'm fine with it.

5 But what we were talking about was I asked what
6 you thought the impacts would be with regards to
7 battery storage as a result of the IRA and how that
8 would impact this overall issue with regards to, you
9 know, more of that generation being used by the
10 customer and less going back into the grid.

11 So the argument about what the rate is or
12 whether it's a net rate or a rate, how do you think
13 that's all impacted by the battery storage and the
14 IRA?

15 MR. LUCAS: Sure. Thank you, Commissioner
16 Shaw, for that question. That is going to be very
17 dependent on this particular location, the particular
18 utility, and the tariff structure that's in place.
19 What we find in places that have had high battery
20 storage adoption rates, it's typically either the
21 rate design, where there is a large ability to, you
22 know, basically arbitrage against high cost to low
23 cost, or where an export rate is low relative to the
24 self-consumption rate.

25 What we find here in Georgia is Georgia rates

1 are relatively low. You know, we're looking in the
2 13 to 15 cent-per-kilowatt-hour range, against an
3 export rate of maybe 3 cents. So that differential
4 is not as large as we see in places where more
5 storage is being adopted.

6 Another driver of storage adoption are specific
7 programs -- utility programs that basically recognize
8 and incent batteries to export during critical times
9 on the grid. There's a program in the northeast
10 called Connected Solutions where they pay for
11 performance on how well that battery performs when
12 the utility calls it. And the customers who have
13 solar-plus-storage systems are compensated for that.
14 So that's an additional revenue stream that a utility
15 program can be stood up to support. Both of those
16 factor into the economic decision to install storage.

17 Unfortunately, right now with the rates the way
18 they are here, those differentials are probably not
19 high enough to support broad economic adoption.
20 There are other reasons why customers may install
21 solar plus storage in addition to the economic piece.

22 But I think that in the near term certainly,
23 and probably in the medium term, having net metering
24 is going to continue to be important to support the
25 rooftop industry. In the long term we may be having

1 a different discussion as costs and value shift over
2 time.

3 COMMISSONER SHAW: I've just got one other
4 question for this panel at this point. In your
5 exhibits here, you know, where it's got the rankings,
6 there's two different rankings, both in the 40
7 percent range.

8 The first one here that's got Hawaii at the top
9 with the number of cumulative capacity, in terms of
10 megawatts, is that -- so California at number two,
11 they've got 10,000 megawatts of generation from
12 rooftop; is that correct?

13 MR. LUCAS: Yes.

14 MR. GIESE: That's correct.

15 MR. LUCAS: So the chart -- the table that
16 you're looking at with Hawaii at the top, that's
17 sorted in terms of --

18 MR. GIESE: Per capita.

19 MR. LUCAS: -- solar per capita. So how much
20 solar for each customer. The cumulative rank there,
21 with California obviously having a higher number and
22 an absolute basis, is listed in that column, but the
23 column is not sorted that way. So, yes, California
24 has that much residential solar.

25 COMMISSONER SHAW: So I'm a little confused on

1 these numbers. Like for Georgia, if it's saying
2 we're -- so this is saying we're producing
3 53 megawatts now?

4 MR. LUCAS: That's -- yeah. From the data set
5 that we pulled, it's 53 megawatts of cumulative
6 residential capacity. That's in the whole state.
7 That's not just limited --

8 COMMISSONER SHAW: Well, let me ask you this.
9 If we're doing 53 based on the current customers,
10 including the pilot; correct?

11 MR. LUCAS: For the whole state.

12 COMMISSONER SHAW: Uh-huh. How many megawatts
13 would it add, do you think, just roughly if just --
14 I'm going to use -- I'm going to use the 80,000
15 customers as an example that's been requested in some
16 of the testimony.

17 MR. LUCAS: Right.

18 COMMISSONER SHAW: How many megawatts would
19 that add, in terms of generation?

20 MR. LUCAS: I think the average system in
21 Georgia Power's territory is about 7 kilowatts. So
22 times 80,000 would be 560,000 kilowatts.

23 COMMISSONER SHAW: Okay.

24 MR. LUCAS: If I'm doing my math right.

25 COMMISSONER SHAW: Okay. That makes sense.

1 Thank you.

2 COMMISSONER MCDONALD: I've got a two-part
3 question. Are we -- with battery storage and
4 rooftop, are we in kindergarten, elementary school,
5 middle school, high school, or in college with the
6 development of -- of storage for rooftop?

7 MR. GIESE: Nationally?

8 MR. YOUNG: No. In Georgia.

9 MR. GIESE: In Georgia.

10 MR. YOUNG: In Georgia specifically,
11 Commissioner?

12 COMMISSONER MCDONALD: Georgia preferably, yes.

13 MR. GIESE: You're not in preschool yet.

14 MR. YOUNG: Yeah. We're -- we're still in
15 diapers.

16 MR. GIESE: Yeah.

17 MR. YOUNG: We're -- about 3 or 4 percent of
18 residential systems today have battery paired with --

19 COMMISSONER MCDONALD: I misstated my question,
20 then. I'm talking about the technology development
21 of battery as it applies to rooftop solar.

22 MR. YOUNG: Oh, yeah, yeah. Sorry.

23 MR. GIESE: So this is an interesting question
24 because it's -- as Thatcher -- as Mr. Young said,
25 you're pretty low for adoption, right, for paired

1 storage?

2 But storage, I mean, that's kind of a boon, I
3 would say, in a bit to Georgia because storage paired
4 with rooftop solar is relatively new, I think, in the
5 scheme of things nationally. Hawaii is obviously the
6 first state that's really done this en masse. I
7 believe 90 percent of the systems installed in Hawaii
8 are paired with storage, for a variety of reasons.

9 But the storage systems that now go in today
10 are much more advanced than they were. You know,
11 when I was working in Hawaii's market in 2015, there
12 were -- there were all kinds of products and it was
13 unclear what their benefits were.

14 But now it's developed in such a way that
15 anything that would be getting installed in Georgia
16 these days would be much more advanced than they were
17 in 2015.

18 COMMISSONER MCDONALD: Is it middle school now
19 where Hawaii was in elementary or preschool?

20 MR. GIESE: I mean, I think on the -- to maybe
21 use your analogy --

22 COMMISSONER MCDONALD: You've got to explain it
23 to somebody like me that doesn't -- you know --

24 MR. GIESE: Yeah. To use --

25 COMMISSONER MCDONALD: We in the South are

1 slow.

2 MR. GIESE: No. Hey, I'm from the South, so
3 I'm, like, the -- not the sharpest crayon in the box.
4 But the way that I understand it is that, I mean,
5 solar paired with storage, Hawaii's policies are at
6 the college level; right?

7 In Georgia, you -- your tariffs don't really
8 consider what the benefits of storage would be;
9 right?

10 So if a customer is pairing storage with their
11 system, they're doing it for reasons that are all
12 their own; right?

13 To have resiliency or to have energy arbitrage
14 not because a program is telling them to install
15 storage; right?

16 And so, in that sense, you're kind of, I would
17 say, underutilizing that resource, unlike Hawaii,
18 which, I mean, three or four weeks ago they created a
19 program that essentially allows aggregate and
20 individual storage capacity to be added onto the grid
21 as a function of total of grid function; right?

22 So they allow a scheduled dispatch program for
23 storage resources.

24 Now, those systems are capable of doing this.
25 They could be installed in Georgia. There's just no

1 structure for that to happen here in Georgia right
2 now; right?

3 This was my point earlier about kind of leaving
4 money on the table in a way. That if you don't
5 develop these programs that incentivize that
6 structure or create that structure, then you're kind
7 of ignoring some of these other commissions that have
8 looked at this and done it.

9 COMMISSONER MCDONALD: Correct me if I'm
10 wrong --

11 MR. GIESE: Yes, sir.

12 COMMISSONER MCDONALD: Going back to
13 Commissioner Shaw's question about California and the
14 10,000 plus megawatts, I was at a NARUC conference
15 and visited -- I think it was Phoenix Utilities or
16 whatever it was. And they were telling me at that
17 time that California was paying them to take some of
18 their energy because they couldn't -- their
19 transmission system would not handle the rooftop
20 solar program that was in California. Is that --

21 MR. YOUNG: That's true.

22 COMMISSONER MCDONALD: Is that a factual
23 statement or am I --

24 MR. LUCAS: Yeah. There were -- there were
25 some instances where there's transmission constraints

1 in California. That's one of the many challenges
2 that they're working on to try to address.

3 The issue like that comes with the scale. And
4 so, again, the scale that Georgia is at right now
5 statewide is so far removed from where California and
6 some of the other high-penetration states are that
7 those types of operational physical issues are just
8 not on the horizon in the near term.

9 So California has a different -- they're at a
10 different place. They're dealing with different
11 challenges. They're addressing them through
12 different policies.

13 All of those things are meaningfully different
14 from what Georgia is and where Georgia sits now.

15 MR. YOUNG: And when you combine that with the
16 ITS, you know, with the integrated transmission
17 system that we have in Georgia, you would not have
18 that same mandatory export to another state issue
19 that California -- southern California utilities had
20 with Arizona.

21 VICE-CHAIRMAN ECHOLS: Let me go back to a
22 question I heard one of the other Commissioners ask.
23 I think it was Commissioner Shaw when he asked about
24 the -- the solar plus storage negating the need for
25 net metering in the future.

1 Because I, too, have heard solar developers in
2 the state say that very thing. That with batteries,
3 you know, half the customers are putting batteries on
4 their installed arrays now and it's going to, you
5 know, keep bumping up because batteries are getting
6 cheaper. Then we're going to have a time when
7 everybody is doing batteries as a part of --
8 especially with the tax credit and there's not going
9 maybe to be a need for net metering.

10 So let me ask you this hypothetical question,
11 Thatcher. I'm going to direct it to you. So if we
12 made a policy decision at the Commission on December
13 the 20th to add an amount of net-metered solar -- I
14 don't know how many megawatts, whatever the
15 Commission would tolerate -- and we -- to keep the
16 program that Georgia Power's already stood up going,
17 because they've got employees they've trained, that
18 went through the learning curve, then the pandemic,
19 all the difficulties, but now they've got it down.

20 To keep that thing going maybe for another
21 three years, could it be that in three years we don't
22 even need to even think about any more net metering
23 for the future?

24 Is that a possibility?

25 MR. YOUNG: Yeah. Absolutely, Commissioner. I

1 mean, I think it's certainly a possibility.

2 And, you know, as I mentioned in my earlier
3 testimony in this proceeding, you know, when we start
4 to consider second generation EVs, right, when you
5 have an 80-kilowatt-hour or a 100-kilowatt-hour
6 battery parked in your garage, the chances that
7 you're going to likely export at any time, unless
8 you're just unaware, is very low; right?

9 So I think -- if I can extend your analogy, I
10 think looking at perhaps -- this Commission should
11 consider when writing policy in the future the
12 correlation between the adoption of generation to EVs
13 and battery storage and how that curve affects the
14 diminishing curve or the diminishing need for monthly
15 netting or net metering in the future for sure.

16 VICE-CHAIRMAN ECHOLS: And with two electric
17 car factories in the state of Georgia with --

18 MR. YOUNG: Yeah.

19 VICE-CHAIRMAN ECHOLS: -- a lot of horsepower
20 being given by officials at all levels, chambers,
21 everyone pushing people to buy these cars because,
22 hey, it's Georgia made.

23 MR. YOUNG: That's right.

24 VICE-CHAIRMAN ECHOLS: And these vehicles are
25 going to be a -- you're going to be able to buy them

1 on a state contract. The counties are going to be
2 getting them. They're Georgia made. You're going to
3 get special consideration. And then as people see
4 them in their counties, others are going to buy them.

5 So us having a very progressive policy that
6 thought about these batteries -- these rolling
7 batteries that you're talking about and creating --
8 creating this infrastructure to make it all work
9 better, I think we might look good in the future for
10 doing something like that.

11 MR. YOUNG: Absolutely, yeah. The convergence,
12 as we've talked about, is coming. And I think y'all
13 are doing a wonderful job of embracing that
14 convergence and understanding the policy impacts of
15 how you continue to do that modestly and push us
16 deeper into the pool as we become stronger swimmers.
17 I think it makes a ton of sense.

18 VICE-CHAIRMAN ECHOLS: I mean, you -- you've
19 been on my radio show. You know I make fun of
20 California all the time.

21 MR. YOUNG: Sure. We all do.

22 VICE-CHAIRMAN ECHOLS: I mean, you know, I'm
23 not trying to get our state to be California.

24 MR. YOUNG: Right.

25 VICE-CHAIRMAN ECHOLS: Am I?

1 I mean, I just want to just keep this program
2 going in a modest -- modest amount so that -- so that
3 we take advantage of all the money we've already
4 spent --

5 MR. YOUNG: That's right.

6 VICE-CHAIRMAN ECHOLS: -- standing the program
7 up, and continuing to have this economic development
8 impact, right, that -- that is provided.

9 MR. YOUNG: That's right. Yeah. I mean, you
10 know, moving us from 42nd to 22nd, that would be
11 pretty good.

12 VICE-CHAIRMAN ECHOLS: Thank you.

13 MR. YOUNG: Thank you.

14 MADAM CHAIR PRIDEMORE: Any other questions,
15 comments, speeches from Commissioners?

16 (No response.)

17 MADAM CHAIR PRIDEMORE: Great.

18 All right. Americans for Affordable Clean
19 Energy.

20 MR. GALLOWAY: No questions, Madam Chair.

21 MADAM CHAIR PRIDEMORE: ChargePoint.

22 MR. FYKES: No questions, Madam Chair.

23 MADAM CHAIR PRIDEMORE: Georgia Coalition of
24 Local Governments.

25 MS. BROWN: Just one, Madam Chair.

1 MADAM CHAIR PRIDEMORE: Yes, Ms. Brown.

2 Do me a favor and fix your mic. Thank you.

3 Thank you.

4 CROSS-EXAMINATION

5 BY MS. BROWN:

6 Q Good afternoon, gentlemen.

7 A (Witness Lucas) Good afternoon.

8 A (Witness Giese) Good afternoon.

9 Q Commissioner Echols used the analogy of the
10 pool and moving from the kiddie pool to the shallow end and
11 only modestly expanding the monthly netting program. And
12 you seem to be in agreement with him on that.

13 Given your collective experience in other
14 states, particularly in the southeast, but across the
15 country, has there ever been a situation where a capped
16 program gets filled up so quickly that lower-income
17 customers and nonprofits that can't move as quickly get left
18 out?

19 A (Witness Giese) I mean, I'll take this one.
20 I -- I am not aware of that occurring. Although, I mean, I
21 oversee 11 states in the south which have various kind of
22 types of programs, some of which are regular net metering,
23 some of which are other structures. I am not aware of a
24 program where certain folks that can take advantage of it
25 are left out.

1 The one thing I'll mention is maybe there --
2 Virginia's RPS allows for a -- what's called a 1 percent DG
3 carve-out. And there's kind of an ongoing conversation
4 about what percentage of DG applies to that RPS. So for the
5 utility Dominion and APCO to meet their goal every year, 1
6 percent of it must come from DG, or can come from DG. And
7 there's an open question about that.

8 But as far as, like, there is no capacity limit
9 to the programs that would meet it. So that is the only
10 kind of somewhat limit that I could imagine. But,
11 otherwise, I'm not aware of one in the south.

12 Q Okay.

13 A (Witness Lucas) Yeah. And one -- one thing in
14 addition is my understanding is the current RNR program, the
15 5,000 customers could have already had systems installed.
16 So some portion of those systems were able to join that
17 tariff, which obviously would have left less room for new
18 customers to come in, be them nonprofits or low-income.

19 So the particular structure that we had on how
20 that queue was filled may have made it more challenging for
21 low-income and nonprofit customers to get in before that cap
22 was shut.

23 A (Witness Young) And then as Commissioner Shaw
24 indicated, you know, with the changes that are coming with
25 the IRA, you're probably aware that the ITC is now

1 transferable in the new IRA, which will open up a host of
2 new pathways for nonprofits and low-income individuals to
3 use other private capital to finance those programs. That
4 was not available at the time of the original pilot program.

5 So I think you would see a -- likely a strong
6 number of nonprofits. We're already in discussion with
7 several of those, several school systems, about installing
8 these systems and utilizing the transfer of the ITC to make
9 that a revenue-neutral engagement for them.

10 Q Okay. You've made me a liar because now I have
11 a couple of follow-up questions. I'm not as involved in
12 Duke territory as you, but I do remember that Duke had a
13 solar rebate program that filled up in, like, a matter of
14 minutes.

15 And I was wondering: Was that a program that
16 had, like, a separate low-income element or was that just a
17 free-for-all for everyone?

18 A (Witness Giese) I believe it was a lottery, but
19 that is subject to check. I'm not super familiar with that
20 rebate program.

21 A (Witness Young) Yeah, I think it was a lottery.
22 There was a carve-out of capacity specifically for
23 nonprofits and low-income.

24 Again, subject to check, I don't remember the
25 exact number. Yeah, it was not as popular as Taylor Swift's

1 latest concert series, but it did fill up very, very
2 quickly. But there were a number.

3 I mean, we -- we did -- in a previous company
4 we did solar on a Calvary Children's Home in South Carolina
5 utilizing that program and it basically made the program
6 work for them. So it was very popular in South Carolina.

7 A (Witness Giese) Can I add, too? I mean,
8 because I'm thinking about this because you're asking these
9 questions. I mean, I think this is a question a little bit
10 that the Commission may have to tackle with, which is: When
11 they think about capacity, how do you think about it?

12 Is it a rolling thing where, you know, as
13 Commissioner Echols talks about, we want to talk about how
14 we innovate these programs and make them better. So we want
15 to build a base and then we kind of innovate to new
16 programs.

17 I think in some ways -- like a capacity limit
18 does give a little bit of a feast or famine signal to the
19 market if it's too small; right?

20 And so, you know, some places that -- I mean,
21 for instance, in Mississippi, we had this conversation and
22 we suggested: Hey, you know, when you hit, like, 3 percent
23 of total load for penetration for rooftop solar, it triggers
24 a proceeding where you then begin to talk about what the
25 next phase of your rooftop solar program looks like.

1 But that all is to say, I think there's, like,
2 different ways that you can tackle this. But, really, like,
3 you should, I think, consider, like, what signals you're
4 sending to those market participants. In this case it would
5 be rooftop solar and installing companies, developers and
6 such.

7 Q Okay. And then the follow-up question from
8 Mr. Young's comment. You talked about the IRA and the
9 transferability provisions. Do those apply to residential
10 or is that only for commercial?

11 Because I think I believed that it was
12 commercial, but I defer to you.

13 A (Witness Young) So my understanding --
14 obviously there's still guidance, you know, to come out from
15 the IRS and treasury on the specifics of that. My
16 understanding it is commercial.

17 Where it would apply in an LMI scenario would
18 be for an LMI developer who's developing new or retrofitting
19 housing that would want to incorporate solar that would then
20 benefit the residents of that community somewhat indirectly.
21 But, yeah, school systems, other nonprofits, you know, can
22 participate independently is my understanding.

23 A (Witness Lucas) Right. But the residential tax
24 credit is not refundable. That's only the commercial one.

25 MS. BROWN: All right. Thank you.

1 MR. GIESE: Thank you.

2 MADAM CHAIR PRIDEMORE: GIPL.

3 MS. WHITFIELD: No questions for this panel.

4 MADAM CHAIR PRIDEMORE: GA Solar.

5 MR. MORELAND: No questions.

6 MADAM CHAIR PRIDEMORE: MARTA.

7 MS. ARIZA: She said she had no questions.

8 MADAM CHAIR PRIDEMORE: Sierra Club.

9 MS. ARIZA: No questions.

10 MADAM CHAIR PRIDEMORE: SACE, Southface.

11 MR. DOWDY: No questions.

12 MADAM CHAIR PRIDEMORE: Georgia Public Service

13 Commission.

14 MR. THOMAS: No questions.

15 MADAM CHAIR PRIDEMORE: Hmm. Expected that.

16 I had hoped that you'd change your mind over

17 lunch.

18 Georgia Power.

19 MR. HEWITSON: Thank you, Madam Chair.

20 CROSS-EXAMINATION

21 BY MR. HEWITSON:

22 Q Gentlemen, good afternoon.

23 A (Witness Young) Good afternoon.

24 A (Witness Lucas) Good afternoon, Mr. Hewitson.

25 Q I want to go back to one of the things

1 Commissioner McDonald was asking a little bit earlier.

2 Georgia got to No. 4 in the country in terms of
3 solar -- overall solar by focusing on programs that are at
4 or below avoided cost; is that right?

5 A (Witness Young) I mean, not entirely, no. I
6 mean, some of those early solicitations by the company were
7 above avoided cost.

8 Q But the vast majority of what Georgia has done
9 -- Georgia Power has done in those programs over the last
10 several years has been at or avoided cost; right?

11 A (Witness Young) I mean, subject to check, I
12 would say a substantial amount in the most recent years,
13 yes.

14 Q And that's mainly so that all customers benefit
15 from it and it doesn't increase rates for other customers;
16 right?

17 A (Witness Young) Yes. That would be correct,
18 yeah.

19 Q Okay. And monthly net metering compensates the
20 customer generator at a level above avoided cost; right?

21 A (Witness Young) It does, yes. In the pilot
22 structure, yes, it did.

23 Q All right. On page 22, lines 13 through 17 of
24 your testimony, you say there is no cost shift for monthly
25 netting because there is no undercollection of revenues. Is

1 that your testimony in that section?

2 A (Witness Lucas) Can you give the line number
3 again, please?

4 Q Yeah.

5 A (Witness Giese) Thirteen.

6 Q Twenty-two, lines 13 to 17.

7 A (Witness Lucas) Correct.

8 Q And your analysis goes back to your argument
9 related to the earnings band; right?

10 That -- I understand, Mr. Lucas, you're right,
11 we had a robust discussion about it last time you were here.
12 But just for reference, that's essentially the argument
13 you're relying on; right?

14 A (Witness Lucas) It -- it's part of the
15 argument. So the revenue erosion element is with respect to
16 the adjustment coming and how that affects the ROE band and
17 so on, as we talked before.

18 The other side of that component, which we have
19 also talked about a lot, is that the company has not done a
20 cost-based analysis on whether these customers are actually
21 less costly to serve.

22 And so the implication of the company's
23 position is that any revenue erosion is not accompanied by a
24 reduction in cost of service; therefore, it's a cost shift.
25 That's something that we've challenged in our testimony.

1 Q Okay. And revenue requirements are set in rate
2 cases; right?

3 A (Witness Lucas) Yes.

4 Q All right. And rates are set to collect the
5 revenue requirements at the authorized ROE set point; do you
6 agree?

7 A (Witness Lucas) They are set to collect
8 revenues at the authorized ROE set point based on a number
9 of assumptions that go into there, such as forecasted energy
10 use, customer growth, et cetera.

11 Q Right. And Georgia Power's revenue forecasts
12 have not been challenged in this rate case, have they?

13 A (Witness Lucas) I don't know if the revenue
14 forecast explicitly because obviously the companies who have
15 challenged the ROE and the capital structure, which directly
16 impacts the revenue requirement. So I don't think it's
17 appropriate to say nobody has challenged the revenue
18 requirement numbers.

19 Q No. That's -- I'm sorry. And maybe I
20 misspoke.

21 Nobody has challenged the company's revenue
22 forecasts in this case?

23 A (Witness Lucas) In terms of the -- how much
24 money it's going to collect from customers in the future?

25 Q The forecasts provided by Georgia Power in this

1 case, nobody has challenged; right?

2 The only party that filed testimony was staff
3 and they didn't challenge it; they offered a couple of
4 tweaks?

5 A (Witness Lucas) We -- we did actually have some
6 commentary on this particular element in our direct -- --
7 or, sorry, our first round of testimony. This was on
8 page 98 of our original testimony where we were looking at
9 the company's use of load meters, instead of AMI.

10 If you guys recall from the last discussion,
11 there was a question as to why the company was not using its
12 AMI metering data and instead was relying on a sample of
13 load meters. And we did, in our first round of testimony,
14 an analysis -- it's confidential so I can't say the
15 numbers -- that show differences between the AMI billing
16 data and the load study billing data.

17 And the results of that, depending on the
18 particular class, was that there was differences that were
19 material in the forecasted billing determinants, which then
20 would, therefore, impact the revenue that's collected
21 through those rates. So we did offer some testimony on
22 that.

23 Q And your point was -- your point in that
24 testimony was that there's a technology that you believe
25 would provide perhaps more accurate forecasts?

1 A (Witness Lucas) The specific result of my
2 testimony, as you can see on page 98 of the trade secret
3 version, is that -- and continuing on to page 99, is that
4 there was a nontrivial amount of revenue impact for the
5 company's revenue forecasts based on these data that we
6 think may not be the most appropriate.

7 Q Okay. And I won't give the number --

8 A (Witness Lucas) Go ahead.

9 Q -- that you call nontrivial because -- given
10 that it was the trade secret and I'll honor that --

11 Revenue to be collected from the residential
12 group is primarily a function of rate times kilowatt-hour
13 sales; right?

14 A (Witness Lucas) Yes. Again, subject to the
15 various forecasts that the company is making to -- you know,
16 it does test years on a -- on a forward basis. So it takes
17 historical numbers and adjusts them for a number of factors
18 and then projects those forward based on anticipated changes
19 in usage patterns and so on.

20 Q Right. So if the company forecasts lower
21 kilowatt-hour sales because customers are self-generating
22 their own energy, rates will have to go up to collect the
23 revenue requirement; right?

24 A (Witness Lucas) It depends on how the company
25 incorporates the other side of the equation. So, again,

1 you're talking about the revenue side. There's also cost
2 side.

3 What we're talking about here is the revenue
4 requirement that's going to be a function of the company's
5 need to earn a return, which is a balance between the
6 revenues and the costs. So there's two ends of that
7 equation. If the revenues go up and the costs go up, then
8 that differential is the same.

9 If the revenues come down and the cost comes
10 down, then that differential --

11 Q When you say the cost, do you mean -- are you
12 talking about the revenue requirements?

13 A (Witness Lucas) I'm talking about all the costs
14 that are subtracted out to get to your end point. The
15 company in 2021, if I'm remembering the ASR report, was
16 authorized based on the center point of the rates to have
17 profits of \$1.6 billion. So that's the number I'm saying.
18 It's based on a revenue number that's higher, subtracts out
19 costs to get to that \$1.6 billion number.

20 Q Okay. And that -- that wasn't really the
21 question I was asking you. Going back to the question that
22 revenue to be collected from a residential group is
23 primarily a function of rates times kilowatt-hour sales;
24 right?

25 A (Witness Lucas) Correct.

1 Q And if the revenue requirement stays the same,
2 but the kilowatt-hour sales decrease, then the only way to
3 get to that revenue requirement is to increase rates; right?

4 A (Witness Lucas) Right. But what I'm
5 challenging is the revenue requirement will not stay the
6 same because the cost side of the equation would also come
7 down. So it is not the case that revenues stay constant.

8 It's the case that if you did this and factored
9 these numbers in, as we're talking about, the whole thing
10 would shift down. And you would have a shift in both of
11 those, revenues and costs.

12 Q Right. And you're advocating -- you're
13 advocating for a revenue requirements adjusted in a future
14 rate case. What I'm talking about is the rate case that
15 we're in right here.

16 If revenue requirements are set for once the
17 Commission votes on December 20th, hopefully, we will have a
18 revenue requirement that's set; right?

19 A (Witness Lucas) Yes. So the Commission will
20 vote on capital structure, an ROE and various adjustments
21 and you'll run that through your model and produce a revenue
22 requirement.

23 Q Right. And so once that's set, you're going to
24 earn that revenue, you're projected to earn that revenue by
25 kilowatt-hour sales times rates. That's the only two

1 factors in it for the most part for the residential class;
2 right?

3 A (Witness Lucas) Once those numbers are locked
4 in, yes.

5 Q Okay. Thank you.

6 On page 52, line 25, you take issue with
7 Dr. Gattie's conclusions regarding the IRA and call them
8 pure speculation that should be given no weight by the
9 Commission. Is that your testimony?

10 A (Witness Lucas) I'm sorry. 52 -- I'm sorry.
11 Which line?

12 Q Line 25.

13 A (Witness Lucas) Yes. In this particular case,
14 it was referencing the quote that was up in line 21, that
15 was referring to the previous paragraph where he's basically
16 saying: Given the generous benefits provided by the IRA and
17 Georgia's proven track record in developing these resources,
18 I conclude that further ratepayer investments are not needed
19 to encourage this growth, and additional subsidies would
20 likely result in nothing more than additional windfall
21 payments to solar installers and developers on the backs of
22 ratepayers.

23 And as I say in the next Q and A, he provided
24 zero support for this testimony. There's nothing in his
25 testimony that did anything looking at the business trends,

1 at the business models of installers, about the definition
2 of windfall profits and so on. It was pure speculation on
3 his part, and, therefore, I'm saying it shouldn't be given
4 weight.

5 Q Do you disagree that the Inflation Reduction
6 Act is the most transformational clean energy policy in
7 history?

8 A (Witness Lucas) I would say that's probably an
9 accurate characterization of that bill.

10 Q Okay.

11 A (Witness Lucas) That's a different question
12 than what we're talking about here, though.

13 Q Okay. And do you agree that over the next
14 ten years the IRA will lead to 69 percent more solar
15 deployment that would otherwise be expected under a non-IRA
16 scenario?

17 A (Witness Lucas) It sounds roughly in line with
18 some of forecasts, subject to check on that particular
19 reference.

20 MR. HEWITSON: Yeah. May we approach?

21 MADAM CHAIR PRIDEMORE: You may.

22 MR. HEWITSON: All right. While Marzo is
23 passing this out, this is the -- this is what I will
24 mark as Georgia Power's Exhibit 44. And this is the
25 SEIA IRA fact sheet, which I accessed from SEIA's

1 public web page and it seems to be a fact sheet
2 discussing the IRA.

3 (The document referred to was marked for
4 identification as GPC Exhibit 44.)

5 BY MR. HEWITSON:

6 Q I'm assuming you all are -- at least two of you
7 all are familiar with it. Perhaps you also, Mr. Young?

8 A (Witness Lucas) Yes.

9 A (Witness Young) I am.

10 A (Witness Giese) Yes, we are.

11 Q Okay. And do you see that it also says that by
12 2032, the U.S. will have installed 682 gigawatts of total
13 solar capacity, more than five times the amount installed
14 today?

15 A (Witness Lucas) I'm just trying to find that
16 lang- -- yes, I see that.

17 Q Okay. And the IRA will drive an additional
18 222 gigawatts of solar over the next 10 years when compared
19 to non- -- no IRA scenarios; right?

20 A (Witness Lucas) That's correct. And these are
21 nationwide numbers. That's right.

22 Q All right. And 10 years from now, there will
23 be enough solar power installed to power nearly every home
24 east of the Mississippi; right?

25 A (Witness Lucas) Correct.

1 Q And that statement -- all those statements are
2 part of your organization's fact sheet on the IRA; right?

3 A (Witness Lucas) Correct.

4 Q Okay. So -- well, on page 55 -- well, pages 55
5 to 64, you argue that Georgia Power should pay capacity
6 value to exported energy; is that right?

7 A (Witness Lucas) Was that 55? I'm sorry.

8 Q Yeah. Starting at 55 and -- I think starting
9 at 55 and going to 64.

10 A (Witness Lucas) Yes, I see that.

11 Q Okay. And the value of export energy is
12 determined currently in Georgia by the company's renewable
13 cost benefit framework; is that your understanding?

14 A (Witness Lucas) Correct.

15 Q Okay. And the RCB framework was approved as
16 part of the company's 2022 IRP earlier this year; correct?

17 A (Witness Lucas) Yes. I think it was in place
18 before, but I believe it was reaffirmed in that discussion.

19 Q Okay. So while you argue in your testimony
20 here in this proceeding that export energy provides capacity
21 value to the system, the RCB framework does not give such
22 value to export energy, does it?

23 A (Witness Lucas) It doesn't. Then I had a
24 discussion in here about some of the changes that have
25 occurred in that framework over time, including some

1 discussions in the IRP where the Commission asked for, I
2 believe, company and staff and other stakeholders to
3 investigate the capacity value associated with solar and
4 behind-the-meter resources.

5 And I think our closing recommendation is for
6 the Commission to continue to develop that method. And when
7 that value is established, that it should be applied to the
8 export credit.

9 Q Okay. But currently you understand that in
10 Georgia the RCB framework does not include capacity value
11 for export energy?

12 A (Witness Lucas) Currently, that is correct.

13 Q Okay. And you're aware, I would imagine, that
14 GASEIA signed on to that as a joint recommendation to this
15 Commission that the RCB framework was to be used to value
16 the export energy from behind-the-meter solar; right?

17 A (Witness Lucas) I think at the time I was not
18 directly involved in this. My understanding is that GASEIA
19 did sign on to that, but it was part of a broader settlement
20 agreement that included many things, in addition to this one
21 particular element on the renewable cost benefit framework.

22 Q I would agree with that, Mr. Lucas. Thank you.

23 MR. HEWITSON: That's all the questions I have
24 for you, gentlemen. Thank you for your time.

25 MR. LUCAS: Thank you, sir.

1 MR. YOUNG: Thank you.

2 MADAM CHAIR PRIDEMORE: Redirect.

3 REDIRECT EXAMINATION

4 BY MR. THOMASSON:

5 Q I have one redirect about the exhibit that
6 Mr. Hewitson asked you about from GASEIA's website. With
7 regard to the 69 percent, five times as much solar capacity,
8 all these large number projections that the industry
9 association is making, are those limited just to rooftop
10 solar or does that include commercial and utility-scale
11 solar?

12 A (Witness Lucas) It includes everything.

13 Q And is it your testimony earlier in response to
14 Commissioner questions that many or most of the
15 solar-related incentives in the IRA are focused on
16 utility-scale and commercial systems?

17 A (Witness Lucas) Yes.

18 Q And so would you expect the same 69 percent
19 increase in Georgia residential solar rooftop growth based
20 on the IRA as these overall national numbers for all sectors
21 of solar?

22 A (Witness Lucas) Not on the basis of the IRA
23 alone, no.

24 Q And did Dr. Gattie present any analysis that
25 made that connection between these large projections from

1 the IRAs as being transformational and how those relate
2 specifically to the Georgia rooftop market?

3 A (Witness Lucas) No, he did not.

4 MR. THOMASSON: Okay. That's all I have.

5 I'd ask that our exhibits be moved into
6 evidence and that the panel be excused.

7 MADAM CHAIR PRIDEMORE: So moved. You're
8 excused.

9 (GASEIA, SEIA, Vote Solar Exhibit 1 was
10 admitted into evidence.)

11 MADAM CHAIR PRIDEMORE: SACE/Southface, Brown,
12 Hathaway.

13 MR. DOWDY: Thank you, Madam Chair, Commission.
14 Southern Alliance for Clean Energy and Southface
15 Energy Institute call Dr. Marilyn Brown and Mr. Alden
16 Hathaway to the stand.

17 Before you sit down, if you could raise your
18 right hands.

19 Thereupon,

20 MARILYN K. BROWN, PH.D.,
21 ALDEN M. HATHAWAY, P.E., C.E.M.,
22 having been duly sworn, testified as follows:

23 MR. DOWDY: Thank you. You can be seated.

24 DIRECT EXAMINATION

25 BY MR. DOWDY:

Q Starting with you, Dr. Brown, would you give

1 your full name and your occupation.

2 A (Witness Brown) Yes. My name is Marilyn A.
3 Brown and I am a professor at the Georgia Institute of
4 Technology. I am leading a research program there which is
5 called Drawdown Georgia. And that's in collaboration with
6 universities across the state of Georgia and also more than
7 45 corporate partners.

8 I'm a retired two-term regulator of the
9 Tennessee Valley Authority, the nation's largest public
10 power provider, which gives me an appreciation for the
11 challenges and the important roles that you play.

12 I am also an elected member of both the
13 national Academy of Sciences and Engineering and a certified
14 energy manager. Prior to joining the faculty at Georgia
15 Tech about 15 years ago, I was on the senior management team
16 of the U.S. Department of Energy's Oak Ridge National
17 Laboratory where I managed its energy efficiency, renewable
18 energy, and electric grid research program.

19 The positions and statements contained in my
20 testimony are my own and are not necessarily the opinions of
21 my employer, the national academies, or my Drawdown Georgia
22 partners. My business address is 685 Cherry Street,
23 Atlanta, Georgia 30301.

24 Q Thank you, Dr. Brown.

25 Did you cause to have prefiled in this

1 proceeding 25 pages of question-and-answer testimony?

2 A (Witness Brown) Yes, I did.

3 Q Do you have any revisions or corrections to
4 that testimony?

5 A (Witness Brown) I do not.

6 Q So if the questions were asked of you today
7 from the stand, your answers would be the same as those
8 prefiled?

9 A Yes.

10 MR. DOWDY: Madam Chairman, I would ask that
11 the testimony of Dr. Brown be copied into the record
12 as if given orally from the stand.

13 MADAM CHAIR PRIDEMORE: So moved.

14 (Whereupon, the prefiled direct testimony of
15 Marilyn K. Brown, Ph.D. follows:)

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**STATE OF GEORGIA
BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION**

In Re: Georgia Power Company's 2022 Rate Case	)	
	)	DOCKET NO. 44280
	)	

**DIRECT TESTIMONY OF DR. MARILYN A. BROWN
ON BEHALF OF
SOUTHERN ALLIANCE FOR CLEAN ENERGY AND
SOUTHFACE ENERGY INSTITUTE, INC.**

November 18, 2022

I. INTRODUCTION

Q1: PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A1: My name is Dr. Marilyn A. Brown. I am a Regents' and Brook Byers Professor of Sustainable Systems in the School of Public Policy at Georgia Tech. My business address is 685 Cherry Street, Room 312, Atlanta, GA, 30313. I have prepared this testimony in my personal capacity. The positions and statements contained in this testimony are my own and are not the opinions of my employer.

Q2: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A2: I am testifying on behalf of Southern Alliance for Clean Energy ("SACE") and Southface Energy Institute, Inc. ("Southface").

Q3: PLEASE SUMMARIZE YOUR QUALIFICATIONS AND WORK EXPERIENCE.

A3: I earned a Bachelor of Arts degree in Political Science from Rutgers University, a Master in Regional Planning degree from the University of Massachusetts, a Doctor of Philosophy degree in Geography from Ohio State University, and a Certified Energy Manager from the Association of Energy Engineers. I am an elected member to both the National Academy of Sciences and the National Academy of Engineering.

Prior to joining the faculty at Georgia Tech, I was on the senior management team of the U.S. Department of Energy's Oak Ridge National Laboratory, the nation's largest energy research laboratory. I co-founded the Southeast Energy Efficiency Alliance and chaired its Board of Directors for several years.

1 I have served on the Boards of the American Council for an Energy-Efficient
2 Economy and the Alliance to Save Energy and was a Board Commissioner with the
3 Bipartisan Policy Center. I have also served on eight National Academies committees and
4 currently serve on the Editorial Boards of *Energy Policy*, *Energy Efficiency*, and *Energy*
5 *Research and Social Science*.

6 I am a retired two-term regulator of the Tennessee Valley Authority (“TVA”), the
7 nation’s largest public power provider. During those eight years, I chaired TVA’s Nuclear
8 Oversight Committee that was responsible for bringing the nation’s last nuclear unit online
9 (Watts Bar Unit 2), and I helped to expand TVA’s energy efficiency program offerings.
10 From 2014-2018, I also served on the U.S. Department of Energy’s Electricity Advisory
11 Committee, where I led the Smart Grid Subcommittee.

12 My research focuses on the design and impact of policies aimed at accelerating the
13 development and deployment of sustainable energy technologies, with an emphasis on the
14 electric utility industry; the integration of energy efficiency, demand response, and solar
15 resources; energy equity, and strategies to improve resiliency to disruptions. I have written
16 six books and authored more than 250 publications related to these various energy issues.

17 My work has had significant visibility in the policy arena as evidenced by my
18 briefings and testimonies before state legislative bodies and Committees of both the U.S.
19 House of Representatives and Senate and governmental and professional meetings around
20 the world.

Q4: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION (“GPSC” OR “THE COMMISSION”)?

A4: Yes. I testified in Georgia Power Company’s 2022 Integrated Resource Planning and Demand Side Management dockets (Docket Nos. 44160 and 44161).

Q5: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A5: The purpose of my testimony is to offer and explain the following recommendations and rebuttals:

1. The Commission should order Georgia Power to reinstate the Renewable Non-Renewable (“RNR”) monthly netting tariff without a cap for three years. During that time, hold workshops to consider alternative compensation rates for excess generation. Having an unlimited cap for the next three years will enable customer-sited resources to support system reliability, local economic development, and participation of Georgia residents in the 30% investment tax credits funded by the Inflation Reduction Act. Georgia is not close to meeting the achievable potential for rooftop solar to supply a valuable peak resource. Nor is Georgia at a level of penetration that warrants valuing excess distributed solar generation to the grid at anything less than retail price.
2. A cost of service study should be conducted. Not all of the benefits of distributed solar are being accounted for in the cost-shift Exhibit (LPE/LTL-1) in Evans and Legg’s testimony. Benefits that are excluded include enhanced employment, resilience, and grid security, as well as reduced and avoided T&D infrastructure costs and line losses, air pollution, and greenhouse gas emissions.

1 3. The proposed interconnection fee for participation in the RNR tariff should be reduced
2 because it is excessive, based on my assessment of practices elsewhere. In addition, it
3 should be waived for income-qualified customers.

4 4. Reinstating the RNR monthly netting tariff has co-benefits to the broader economy
5 through job creation, and it enhances access to distributed solar for low- and moderate-
6 income households.

7 **Q6: ARE YOU SUBMITTING EXHIBITS ALONG WITH YOUR TESTIMONY?**

8 A6: Yes, I am submitting five (5) exhibits along with my testimony, as follows:

9 1 – MAB-EXHIBIT-1: Curriculum Vitae of Dr. Marilyn A. Brown;

10 2 – MAB-EXHIBIT-2: Distributed Energy Generators as Percentage of
11 Households, through June 2022;

12 3 – MAB-EXHIBIT-3: Slow Growth Forecasted for Distributed Solar in Georgia:
13 2016-2025;

14 4 – MAB-EXHIBIT-4: Fewer Distributed Solar Systems in 2019 Means \$429
15 Million in Tax Revenues Did Not Come to Georgia from 2010-2019; and

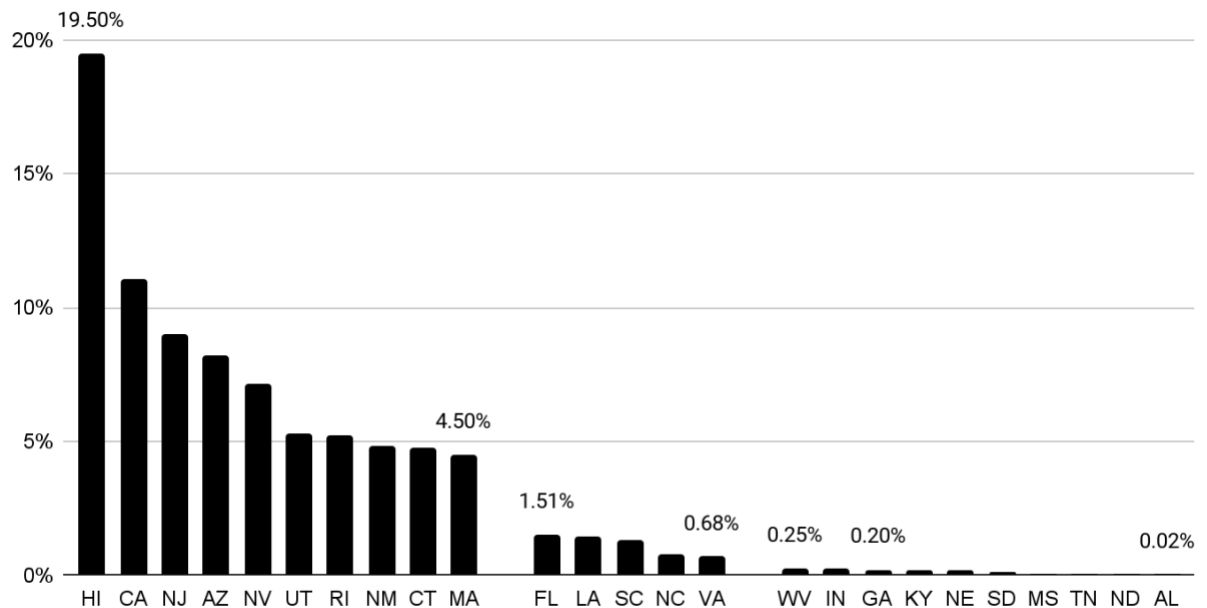
16 5 – MAB-EXHIBIT-5: Residential Distributed Generation Interconnection Fees
17

18 **II. ACHIEVABLE POTENTIAL FOR ROOFTOP SOLAR IN GEORGIA**

19 **Q7: HOW DOES GEORGIA'S ROOFTOP SOLAR PENETRATION AND ITS**
20 **TECHNICAL POTENTIAL COMPARE TO OTHER STATES?**

A7: By June of 2022, 10 States had levels of rooftop solar penetration ranging from 4.5% to 19.5% of their residential customers. At only 0.2%, Georgia ranked 43rd in the U.S. for residential rooftop solar penetration (Figure 1).

Figure 1. Distributed Energy Generators as Percentage of Households, through June 2022



Source: EIA 2022 for Number of Net Metering and Non-Net Metering Generators and U.S. Census Data 2021 for Households.

The technical generation potential of rooftop solar in Georgia is estimated to be 44 TWh/year of electricity generation.¹ That represents 34% of Georgia's electricity sales,

¹ Gagnon, P., R. Margolis, J. Melius, C. Phillips, and R. Elmore, 2016, *Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment*, National Renewable Energy Laboratory (NREL) Technical Report NREL/TP-6A20-65298, Table 6, Available at, <https://www.nrel.gov/docs/fy16osti/65298.pdf>.

1 which is more than Arizona and Massachusetts – two of the top 10 rooftop solar states.
2 Georgia has a higher technical potential for rooftop generation than all other Southeastern
3 states except Florida and North Carolina.
4

5 **Q8: WHY DOES GEORGIA HAVE SO LITTLE ROOFTOP SOLAR?**

6 A8: According to a recently published analysis of net metering policies, Georgia and Kansas
7 are tied for last place on a scale ranging from the most to the least supportive of rooftop
8 solar.² States were ranked according to five features of their net metering programs: system
9 size caps, program size caps, excess utility compensation level, number of eligible
10 technologies, and whether or not consumers own Renewable Energy Credits (RECs).³
11

12 **Q9: HOW DOES ELECTRICITY GENERATION FROM RENEWABLE SOURCES IN**
13 **GEORGIA COMPARE TO OTHER U.S. STATES?**

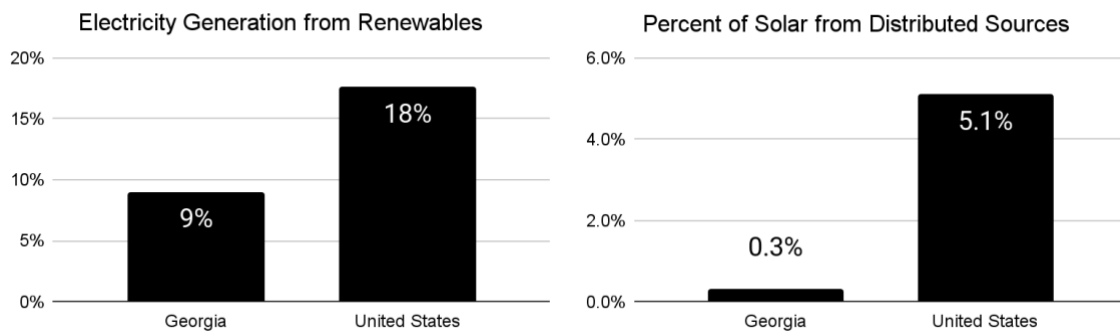
14 A9: Georgia Power is a leader in utility-scale solar, but it lags the nation in overall renewables
15 and in rooftop solar. Renewable resources generated only 9% of the state's electricity in
16 2019, while across the U.S., renewables constituted nearly twice that amount at 17.6%. In
17 2019, Georgia's distributed solar represented only 0.3% of its total solar generation, while

² Smith, K.M, C. Koski, and S. Siddiki, 2021, Regulating net metering in the United States: A landscape overview of states' net metering policies and outcomes, *Electricity Journal*, Volume 34, Issue 2.

³ *Id.*

distributed solar contributed a total of 5.1% of solar generation nationwide in the same year.⁴

Figure 2. Percent Electricity Generation from Renewable Sources and Distributed Solar: Georgia and the U.S. in 2019



Source: Brown, M.A., R. Tudawe, and H. Steimer. 2022.⁵

Q10: HOW DOES THE FORECAST OF ROOFTOP AND UTILITY-SCALE SOLAR IN GEORGIA COMPARE TO OTHER U.S. STATES?

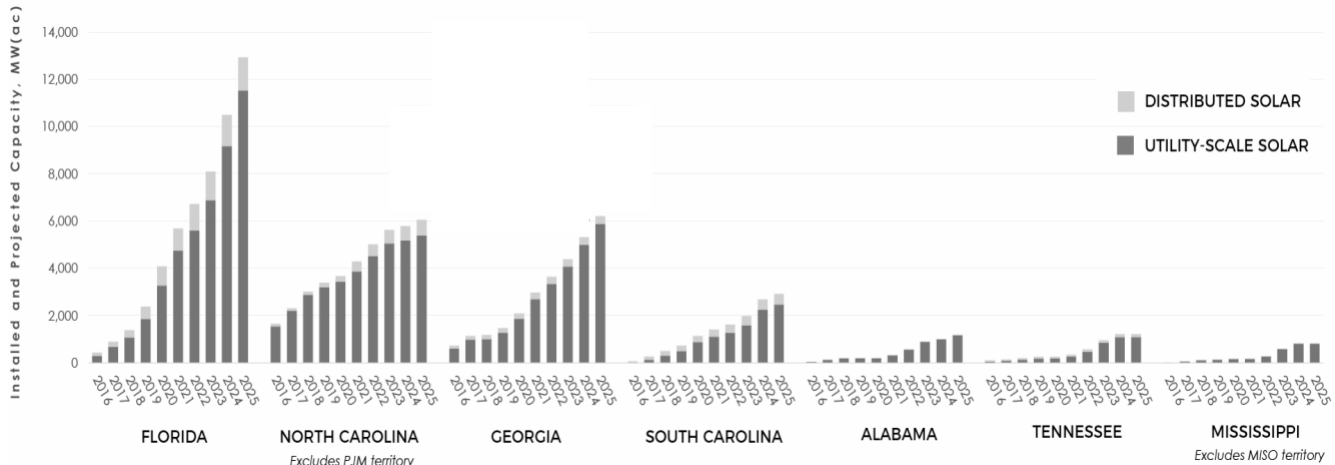
A10: According to *Solar in the Southeast* Report from July 2022, Georgia's utility-scale solar will continue to grow rapidly, while Georgia's distributed solar will grow quite slowly (see Figure 3).⁶

⁴ Brown, M.A., R. Tudawe, and H. Steimer, 2022, Carbon drawdown potential of utility-scale solar in the United States: Evidence from a case study of Georgia, *Renewable and Sustainable Energy Reviews* 161 (June): 112318, Available at, <https://doi.org/10.1016/j.rser.2022.112318>.

⁵ *Id.*

⁶ Jacob, B., July 2022, *Solar in the Southeast, Fifth Annual Report*, Southern Alliance for Clean Energy, Available at, <https://cleanenergy.org/wp-content/uploads/22Solar-in-the-Southeast22-Fifth-Annual-Report-July-2022.pdf>.

Figure 3. Slow Growth Forecasted for Distributed Solar in Georgia: 2016-2025



Source: Jacob, B. July 2022.⁷

Q11: IS ROOFTOP SOLAR IN GEORGIA LAGGING BECAUSE OF ITS LIMITED TECHNICAL POTENTIAL?

A11: No. The Drawdown Georgia project estimates that Georgia has the “technical potential” for 24.3 GW of solar rooftop nameplate capacity, based on the rooftop square footage of existing flat and south-facing angled roofs located in Georgia.⁸

Drawdown Georgia also estimates an achievable potential for an additional 1,475 MW of rooftop solar in Georgia – where “achievable” considers costs, benefits, and

⁷ *Id.*

⁸ Brown, M.A., J. Hubbs, X.V. Gu, and M.K. Cha, 2021, Rooftop Solar for All: Closing the Gap Between the Technically Possible and the Achievable Potentials, *Energy Research and Social Science* (80), Available at, <https://doi.org/10.1016/j.erss.2021.102203>.

1 stakeholder acceptance.⁹ This is 36 times the approximately 40 MW of rooftop solar
2 installed by the 4,157 customers who participated in the RNR monthly netting pilot.¹⁰

3
4 **III. NET METERING DESIGN AND IMPACTS**

5 **Q12: HOW MANY JURISDICTIONS OR UTILITIES HAVE “TRUE NET**
6 **METERING”?**

7 A12: In 2022, 33 states had net metering policies that credited excess electricity generated by
8 customers at the retail rate.¹¹ This is often called “true net metering,” and is the definition
9 used by the Energy Information Agency (EIA) and the Database of State Incentives for
10 Renewables & Efficiency (DSIRE). Out of seven states in the Southeast, North and South
11 Carolina and Florida have state level policies requiring true net metering, and they also
12 have the highest rooftop solar penetration rates in the Southeast averaging at 1% (see
13 Figure 1.). There are several other terms used in the industry, some described below, to
14 describe programs that either don’t net generation one-to-one against consumption, or
15 credit excess generation at less than retail value.

16 The other four Southeastern states (Mississippi, Alabama, Georgia, and Tennessee)
17 don’t allow one-to-one netting of kWh for energy supplied to the grid and are all in the

⁹ Brown, M.A., P. Dwivedi, S. Mani, D. Matisoff, J.E. Mohan, J. Mullen, M. Oxman, M. Rodgers, R. Simmons, B. Beasley, and L. Polepeddi, 2021, A Framework for Localizing Global Climate Solutions and their Carbon Reduction Potential, *Proceedings of the National Academy of Sciences* 118 (31), Available at, <https://doi.org/10.1073/pnas.2100008118>.

¹⁰ Georgia Power’s 2022 Rate Case (Docket 44280), STF-TAI-3-9 Data Response (Document No. 191417).

¹¹ Pickerel, K., 2022 UPDATE: Which States Offer Net Metering, Solar Power World, Originally published on March 27, 2020, Available at, <https://www.solarpowerworldonline.com/2020/03/which-states-offer-net-metering/>.

1 bottom eight states of rooftop solar penetration. Mississippi offers net billing, which is an
2 alternative distributed generation program design that monetizes excess generation at less
3 than retail on a monthly basis rather than rolling over credits at full retail value. Georgia
4 Power's monthly netting tariff pilot is most similar to Mississippi's net billing, but
5 Mississippi includes more participant benefits because it includes a 2.5 cent/kWh adder
6 over avoided cost for excess generation compensation.

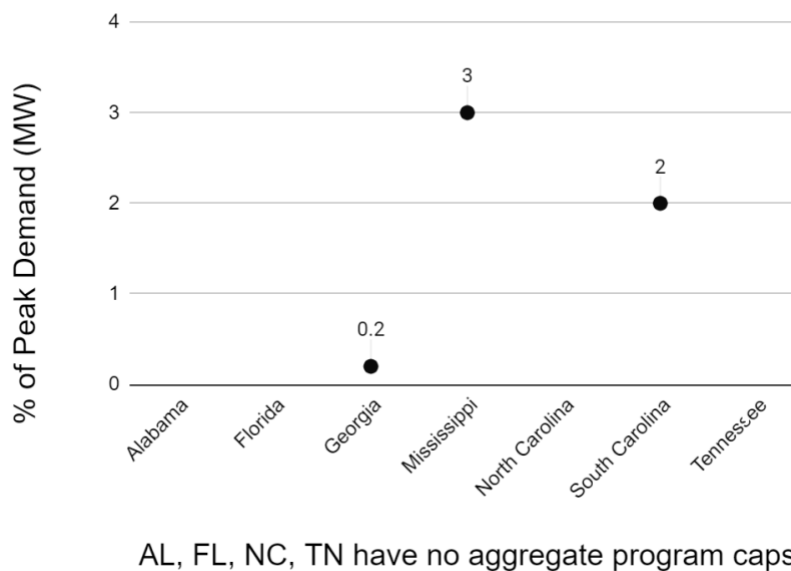
7 Alabama Power has the most restrictive policy in the Southeast by imposing a
8 \$5.41/kW monthly solar tax; it ties with Tennessee for lowest participation in rooftop solar.
9 Georgia Power's proposed instantaneous netting program is most similar to Tennessee's
10 buy-all sell-all program design that yields one of the lowest state penetrations in distributed
11 solar generation in the country. Only a few states, including Arizona and Kentucky, use
12 instantaneous netting. However, Arizona only revised their net metering policy after
13 reaching a high penetration level, over 5%. At 0.2%, Georgia is nowhere near the
14 penetration level that warrants valuing excess generation at less than retail.

15
16 **Q13: HOW DOES GEORGIA POWER COMPANY'S PROGRAM CAP COMPARE TO**
17 **OTHER STATES?**

18 A13: Georgia Power Company's cap on the RNR monthly netting program is the most restrictive
19 in the Southeast, possibly the nation. Alabama, Florida, North Carolina, and Tennessee do
20 not have aggregate program caps. Georgia Power Company's cap is the lowest at 0.2% of
21 annual peak demand in the previous year. In comparison, South Carolina's program cap is
22 2% of the last five-year average peak demand, and Mississippi has a cap of 3% of the

utility's peak demand in the prior year. Many states have unlimited aggregate program caps; the largest caps in the nation, below unlimited, range between 5%-7%. Georgia Power Company's cap on the RNR monthly netting program should be expanded.

Figure 4. Aggregate Capacity Limit of Peak Demand



Source: DSIRE database and State Utility Commissions.

Q14: HOW MANY YEARS HAVE NET METERING PROGRAMS BEEN IN OPERATION AND WHAT ARE TYPICAL LEVELS OF PARTICIPATION?

A14: The first net metering policy was adopted in Idaho in 1980.¹² Following steady growth, a surge of adoption then occurred between 1997 and 2001 (when 15 states adopted). Many states in the Southeast adopted between 2004 and 2015 – KY, NC, FL, AR, SC, and MS.

¹² Smith, K.M, C. Koski, and S. Siddiki, 2021, Regulating net metering in the United States: A landscape overview of states' net metering policies and outcomes, *Electricity Journal*, Volume 34, Issue 2.

1 NEM successor tariffs (NEM 2.0) began adoption in 2013, mostly in states with relatively
2 high levels of solar penetration.¹³ In 2020, U.S. utilities serviced nearly 2.4 million net
3 metering customers, and nearly 2.3 million of these were residential customers.
4

5 **Q15: HOW DOES THE SMALL PENETRATION OF DISRIBUTED SOLAR IN**
6 **GEORGIA IMPACT FEDERAL INVESTMENT TAX CREDIT REVENUE**
7 **COMING INTO THE STATE?**

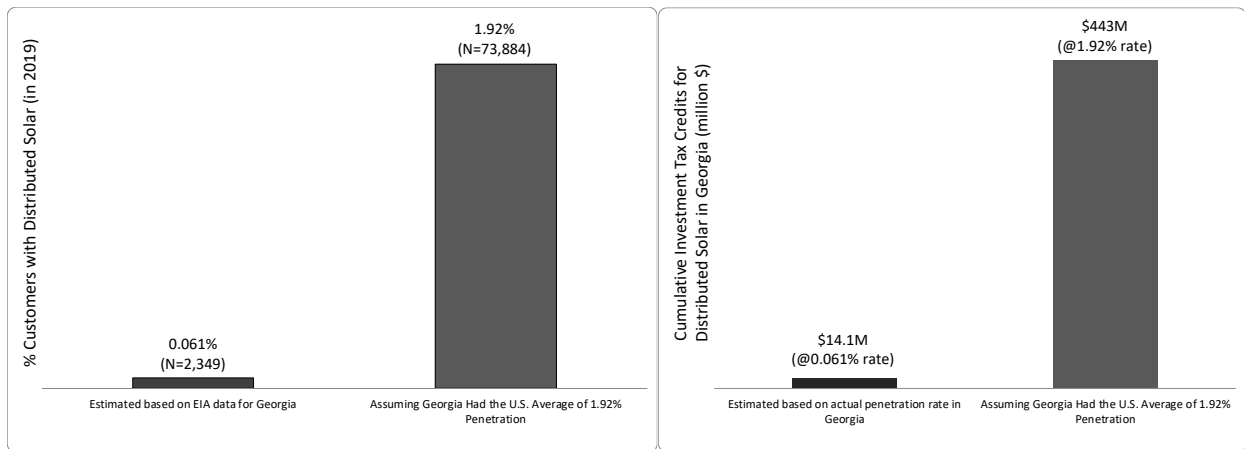
8 A15: To answer this question, we collected state-level data on distributed generation customers
9 in 2019 by combining information from two tables published by the Energy Information
10 Administration (EIA).¹⁴ In 2019, Georgia had only 2,349 distributed generation
11 customers, which represents a penetration rate of 0.061%. The average penetration rate
12 for the continental U.S. is 1.92%. If Georgia had that penetration rate in 2019, it would
13 have had 73,884 customers with distributed generation. At an average cost of \$20,000 per
14 system, each of these customers, assuming they were eligible for the tax credit, could
15 have received approximately \$6,000 in investment tax credits between 2006 and 2019.

¹³ Stanton, T., n.d., *Review of State Net Energy Metering and Successor Rate Designs*, National Regulatory Research Institute, Available at, <https://pubs.naruc.org/pub/A107102C-92E5-776D-4114-9148841DE66B>.

¹⁴ For example, for Georgia this involved combining (1) “Non_Net_Metering_Distributed_2019.xlsx” (Tab ‘state’ sort column B by ‘Georgia’ and Column ‘F’ “number of generators”, obtaining the estimate of 2,168 for 2019) and (2) “Net_Metering2019.xlsx” (Tab ‘monthly totals states’ in Column ‘J’, obtaining the estimate of 181 for 2019). The sum of these two values for Georgia is 2,349 distributed generation customers in 2019. In addition to distributed solar, “Non Net Metering Distributed” includes distributed wind, storage, hydro, fuel cells, internal combustion engines, combined turbine systems and steam). However, the number of non-solar distributed generation customers is small.

This would have been a net gain of roughly \$443 million compared to the approximately \$14 million in tax revenues that Georgians actually received (Figure 5).¹⁵

Figure 5. Fewer Distributed Solar Systems in 2019 Means \$429 Million in Tax Revenues Did Not Come to Georgia from 2010-2019



Data Sources: EIA and U.S. Census.

Q16: HOW CAN DISTRIBUTED SOLAR BE MORE ACCESSIBLE TO LOW- AND MODERATE-INCOME HOUSEHOLDS?

A16: Many states already require utilities to offer discounted rates to income-qualified customers.

Similar approaches could be taken in the context of rooftop PV adoption. Drawing from recommendations in the DOE *Solar Futures Study* (2021), NEM agreements could be structured with higher buy-back rates for low-income customers, as practiced in Mississippi.

For instance, if regular solar customers get Monthly Netting with "buy-back" at the RCB-

¹⁵ US EIA Data for Distributed generation includes solar systems along with other types of generation sources. For my calculation, I assume the vast majority of distributed generation systems are rooftop and distributed solar. This is a rough estimate to illustrate the magnitude of revenue potential in Georgia – it assumes that customers are both eligible for the tax credits and that the majority of systems are solar.

1 modified avoided cost, low-income customers could be offered excess buy-back at retail
2 rate. In addition, low-income households could be exempted from paying interconnection
3 or application fees to increase their access to distributed solar. There are many programs,
4 rates and policies that Georgia Power could offer to increase the access of low-income
5 households to distributed solar, such as on-bill financing or the \$3 million program just
6 implemented in Mississippi, which offers a one-time payment to the installer of systems for
7 low-income customers “recovered through rates in the same manner as demand-side
8 management programs.”¹⁶

9 While the Georgia PSC does not have authority over tax revenues, it is nevertheless
10 notable that, as Mathew Freedman suggests, “Tax revenues are more progressive in their
11 collection. They should be used to offset the needs for subsidy sources for retail rates.” With
12 the IRA’s additional financial support for disadvantaged communities, this would seem a
13 productive route to take. Georgia Power should be encouraged to facilitate such funding in
14 its territory.

15 In addition, IRA offers a 20% bonus investment tax credit for disadvantaged
16 communities to purchase distributed solar. The 20% bonus credit is limited to a qualified
17 low-income residential building project or a qualified low-income economic benefit project.
18 The details are under development, and the projects may or may not be eligible for the RNR
19 tariff.

¹⁶ Order Amending Rules Post-Hearing. MS PSC DOCKET NO. 2021-AD-19 (10/04/2022)

1 There are also many state and community-funded initiatives that can direct
2 resources for solar systems to be installed on low-income homes.¹⁷ The Houston Advanced
3 Research Center is testing a 1,000 watt solar system with storage that can be used for a
4 heating blanket, to save the food in a refrigerator, and to maintain medical devices when the
5 power is out.¹⁸ Such energy security benefits of rooftop solar are generally not considered
6 in utility cost tests.

7
8 **Q17: HOW DOES DISTRIBUTED SOLAR BENEFIT THE ECONOMY OF GEORGIA?**

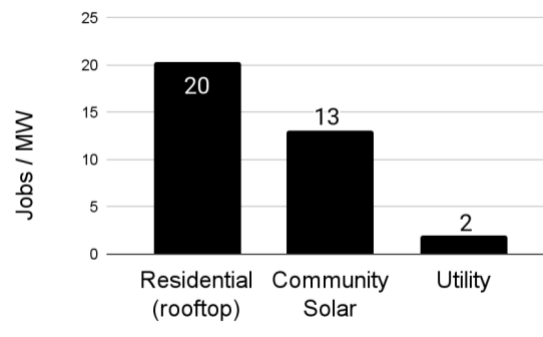
9 A17: On a per-MW basis, “rooftop solar” had a labor intensity rate of roughly 20 workers per
10 MW installed in 2021. Compare this with community solar which has a labor intensity of
11 roughly 13 workers per MW and utility-scale that supports roughly 2 workers per MW (see
12 Figure 6).¹⁹

¹⁷ Reuven Sussman, testimony to the Committee on the Role of Net Metering in the Evolving Electricity Systems, National Academies of Sciences, Engineering, and Medicine, October 18, 2022.

¹⁸ Gavin Dillingham, testimony to the Committee on the Role of Net Metering in the Evolving Electricity Systems, National Academies of Sciences, Engineering, and Medicine, October 18, 2022.

¹⁹ These figures represent the direct downstream jobs associated with the installation of the project, and do not include the indirect manufacturing, O&M and other support jobs created by solar projects.

Figure 6. Labor Intensity Rate of Rooftop, Community, and Utility-Scale Solar²⁰



The more labor-intensive residential sector represents more than half of all solar jobs (85,305) in the U.S. Although utility-scale solar represents the largest segment of solar based on installed capacity in both the U.S. (64% of the total) and Georgia (98%), it has considerably fewer installation and project development jobs than the other two segments.²¹ The more labor-intensive rooftop solar sector therefore offers more opportunity to pull under-resourced labor into the workforce. Its labor force is also more accessible because the vast majority of rooftop solar is installed in urban areas, where the vast majority of roofs are located. As a result, several states such as Illinois with its Clean Energy and Jobs Act, require that solar policies include job training and local job offerings, which will help low-income communities secure a greater share of employment benefits.²²

²⁰ Interstate Renewable Energy Council, 2021, National Solar Jobs Census, pp. 19-21, Available at, <https://irecusa.org/resources/national-solar-jobs-census-2021/>.

²¹ See the Interstate Renewable Energy Council (IREC) [Solar Jobs Census 2021](#) (p. 19). In IREC's Census, workers are only counted if they spend 50% or more of their time on solar-related activities. The [DOE's U.S. Energy and Employment Report](#) (USEER) report counts anyone who spends any time on solar during the year. As a result, the USEER tallies a larger overall solar workforce.

²² Leon, W., C. Farley, N. Hausman, B. Herbert, N.H. Hammer, B. Paulos, et al. 2019. Solar with justice: strategies for powering up under-resourced communities and growing an inclusive solar market. Clean Energy States Alliance, p. 134. <https://www.cleangroup.org/ceg-resources/resource/solar-with-justice/#:~:text=This%20report%2C%20%E2%80%99CSolar%20with%20Justice,lasting%20benefits%20to%20those%20communities.>

IV. FINDINGS AND CONCLUSIONS FROM MY ANALYSIS

**Q18: WHAT ARE THE RESULTS OF YOUR ANALYSIS OF GEORGIA POWER'S
PROPOSED RENEWABLE AND NON-RENEWABLE RESOURCES ("RNR")
TARIFF?**

A18: The results of my review and analysis of Georgia Power's 2022 RNR Tariff are as follows:

1. There is tremendous untapped potential for rooftop solar in Georgia that can be realized with the RNR monthly netting program. Federal government incentives can move markets only when there are enabling rate structures.
2. Investment in, and benefits from, customer-owned rooftop solar resources are not adequately considered within Georgia Power's proposed 2022 Rate Case.
 - a. There are numerous benefits of distributed solar adoption and penetration – to customers, solar installers, and utilities.
 - b. RNR monthly netting should be reinstated to deliver those benefits.
3. The direction, magnitude and even the existence of any cost shift from NEM participants to non-participants is debatable. A cost of service study is needed to quantify these locational value and cost streams.
4. Because low-income, minority, and rental customers are more likely to be non-participants, reinstatement of monthly netting should be accompanied by an effort to partner with other programs and community organizations that can help these subgroups install distributed solar.
5. The \$200 rooftop solar interconnection fee proposed in the Georgia Power rate case appears to be too high, based on a comparison with the fees of other U.S. utilities. I

1 support the Commission staff's recommendation that the interconnection fee for
2 residential solar customers be set at \$100²³. In addition, it should be waived for low-
3 income residential customers.
4

5 **Q19: WILL THE INFLATION REDUCTION ACT (IRA) SIGNIFICANTLY INCREASE**
6 **THE DEMAND FOR RESIDENTIAL SOLAR IN GEORGIA?**

7 A19: Investment tax credits (ITC) for rooftop solar began with the Energy Act of 2005. The ITC
8 was 30% when first offered in 2006 and has been 30% almost every year until 2020 when
9 they were reduced temporarily to 26%. The solar ITC has been one of the most important
10 federal policy mechanisms to support the growth of residential solar in the U.S. In
11 combination with "true" net metering, it has resulted in strong national growth of rooftop
12 solar, but not in Georgia.

13 Despite having had a 30% federal tax credit for distributed solar almost
14 continuously since 2016, Georgia's residential solar electricity has grown slowly. By the
15 end of 2019, distributed solar generated less than 0.03% of Georgia's total electricity
16 generation.²⁴

17 Georgia needs net metering to grow its rooftop solar industry. And the new IRA
18 will not grow distributed solar without net metering, which is needed to make solar
19 financially attractive to homeowners. There is no evidence to support the claim in Dr.

²³ Barber, J., B. Deitchman, and G.A. Watkins, October 20, 2022, Georgia Power's 2022 Rate Case (Docket No. 44280), Joint Direct Testimony (Document No. 191868), Page 103, Line 15.

²⁴ Brown, M.A., R. Tudawe, and H. Steimer, 2022, Carbon drawdown potential of utility-scale solar in the United States: Evidence from a case study of Georgia, *Renewable and Sustainable Energy Reviews* 161 (June): pages 112318, Available at, <https://doi.org/10.1016/j.rser.2022.112318>.

1 Gattie's Testimony that "federal IRA subsidies may be enough" (p.6, l.2-3). There is also
2 no evidence to support the claim in the testimony of Lee Evans (Southern Company
3 Services Inc.) and Larry Legg (Georgia Power Company) that "Considering the recent
4 passage of the federal IRA,..., there is no need to further incentivize the BTM transition
5 through additional rate design programs such as an expanded monthly netting program."
6 (p. 16).

7 **Q20: DOES NET METERING SHIFT COSTS FROM PARTICIPANTS TO**
8 **NONPARTICIPANTS?**

9 A20. In my opinion, this question can be answered appropriately only after Georgia Power
10 legitimately assesses the cost to serve its solar customer-generators and adequately
11 considers the value that those solar customer-generators deliver to the system as well as
12 the benefits that accrue to all customers, including non-participants. For example, Brad
13 Harris, the rates manager for Duke Energy, described the results of an "Embedded Cost
14 Shift Study" in a South Carolina docket for DEC and DEP. On page 21 of 24, in Exhibit 1,
15 he showed that it cost \$651 less to serve net metering customers than to serve non-solar
16 customers on the Duke Energy Carolina's system (\$1,632 vs. \$981).²⁵ This is the kind of
17 study Georgia Power should be required to perform.

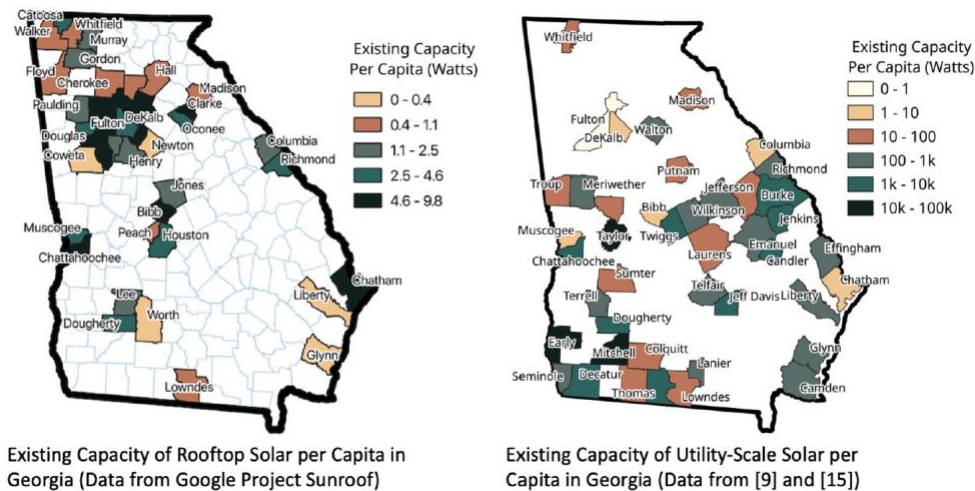
18 Such a study could also identify the ability for distributed solar to add to the
19 resilience of local circuits. Distributed solar can keep the lights on when transmission

²⁵ Harris, Brad, Rebuttal Testimony Of Bradley Harris For Duke Energy Carolinas, LLC And Duke Energy Progress, LLC, February 22, 2021, (Document 297572), Available at, <https://dms.psc.sc.gov/Attachments/Matter/24e37693-e3c1-4444-b13a-a9acc7d7c3dd>

1 infrastructure is damaged during tornados, hurricanes, and other disasters. The testimony
2 of Alden Hathaway builds upon this premise by explaining how the metric of load factor
3 should be used to value grid efficiency as a benefit for all ratepayers.

4 The nearness of rooftop solar to demand loads is shown in Figure 7. Distances to
5 demand loads are important factors in determining the locational value streams of
6 generation assets. Different points in the grid have different transfer capability due to
7 voltage, thermal, security and stability constraints. To complicate matters, locational value
8 depends on the hour of the day and the season. Because implementation of the Renewable
9 Cost Benefit Framework does not take these constraints into account, the full value of
10 distributed solar cannot be determined. A cost of service study could consider these
11 locational value streams.

**Figure 7. Current Capacity of Rooftop Solar (left) and Utility-Scale Solar (right)
 per Capita in Georgia in 2019²⁶**



The testimony by Lee Evans (Southern Company Services Inc.) and Larry Legg (Georgia Power Company) (p. 11 of 17) states that “For a monthly netting customer on the R rate, the Company has calculated the resulting shift in cost to be approximately \$1,356 per year for the average monthly netting participant.” They state further that, “In addition to the cost shift resulting generally from BTM solar, the monthly netting results in an annual cost shift of 1.4 million.” These estimates far exceed the assessment of cost shifts by others.²⁷ Cost shifts have become a concern in California, but their situation is different. 10% of California's electricity comes from distributed solar, and as a result its system coincident peak has shifted approximately two hours into the evening (the

²⁶ Brown, M.A., R. Tudawe, and H. Steimer, 2022, Carbon drawdown potential of utility-scale solar in the United States: Evidence from a case study of Georgia, *Renewable and Sustainable Energy Reviews* 161 (June): pages 112318, Available at, <https://doi.org/10.1016/j.rser.2022.112318>.

²⁷ Barbose, G, 2017, *Putting the Potential Rate Impacts of Distributed Solar into Context*. Berkeley, CA: Lawrence Berkeley National Laboratory. Available at: <https://eta-publications.lbl.gov/sites/default/files/lbnl-1007060.pdf>.

1 peak period for PG&E is 4 - 9 pm after solar production drops). As a result, solar is less
2 valuable as a peak resource.

3 In contrast, **0.03%** of Georgia's electricity comes from distributed solar.²⁸ As a
4 result, rooftop solar remains a valuable peak resource that is able to reduce the need for
5 higher priced peaking resources during hot summer days. Georgia's policies should not be
6 driven by California's situation.

7
8 **Q21: SHOULD GEORGIA POWER ADJUST ITS INTERCONNECTION FEE AS**
9 **PROPOSED?**

10 A21: No, the interconnection fee for residential solar customers should be set at \$100. In
11 addition, low-income customers should be exempted from interconnection fees to increase
12 their access to distributed solar. This will help achieve greater participation by this
13 subgroup that has historically had low levels of participation in net metering programs.
14 Virginia just approved a minimum bill for community solar participants, but low-income
15 customers are exempt from it.

²⁸ U.S. Energy Information Administration, 2021, Electricity Data Browser, Available at,
<https://www.eia.gov/electricity/data/browser/>.

1

Figure 8. Residential Distributed Generation Interconnection Fees

		<u>Fixed Initiation Fee</u>	
		No	Yes
<u>Variable Fees per System Size</u>	No	Pedernales Electric Cooperative (TX) Arkansas IOUs and Co-ops Sacramento Muni. Energy Utility District Florida Power and Light South Carolina Tucson Electric Orlando Utilities Commission Kentucky Jacksonville Electric Authority Xcel Energy New Mexico Austin Energy	North Carolina \$50 application fee New Mexico \$50 application fee SCE \$75 one time Connection Fee Mississippi Power \$87 one time meter fee Eversource \$100 application fee Liberty Utility \$100 application fee Proposal: Georgia Power \$200 one time Connection Fee SDG&E \$132 one time Connection Fee PG&E \$145 one time Connection Fee
	Yes	Existing: Georgia Power \$5/kW one time connection fee Arizona Public Service \$0.93/kW Monthly grid access charge New York IOUs \$0.69-\$1.09/kW Monthly Capacity Charge El Paso Electric \$15 monthly flat fee Alabama Power \$5.41 kW Monthly Capacity Charge Kansas Evergy \$3/kW (Oct-May) or \$9/kW (June-Sept) monthly demand charge	Some utility companies require larger fees for C&I customer with large distributed solar systems

2

V. SUMMARY OF RECOMMENDATIONS

3

Q22: CAN YOU SUMMARIZE YOUR RECOMMENDATIONS FOR THE COMMISSION?

4

5

A22: I respectfully suggest the following four recommendations for consideration by the Commission:

6

- 1 1. Reinstate the Renewable Non-Renewable (“RNR”) monthly netting tariff without a cap
2 for three years. During that time, hold workshops to consider alternative compensation
3 rates for excess generation.
- 4 2. Conduct a cost of service study. Such a study might reveal that (per the experience in
5 South Carolina) it costs less for the Georgia Power Company to serve net metering
6 customers than to serve non-solar customers.
- 7 3. The interconnection fee for residential solar customers should be set at \$100, it should
8 be waived for low-income households, and Georgia Power Company’s cap on the RNR
9 monthly netting program should be expanded.
- 10 4. Consider ways to enhance access of low- and moderate-income households to
11 distributed solar.

12
13 **Q23: DOES THIS CONCLUDE YOUR TESTIMONY?**

14 A23: Yes.

Attachments

VITA: Marilyn A. Brown – November 16, 2022

Current Employment

Regents & Brook Byers Professor of Sustainable Systems
School of Public Policy
Georgia Institute of Technology
Atlanta, GA 30332-0345
404-385-0303; mbrown9@gatech.edu
[Website: http://marilynbrown.gatech.edu/](http://marilynbrown.gatech.edu/)

Affiliations:

- Member, National Academy of Engineering
- Member, National Academy of Sciences
- Co-Director, Climate and Energy Policy Lab
<http://cepl.gatech.edu>
- Joint Faculty Member, Oak Ridge National Laboratory

Marilyn Brown is a Regents' Professor in the School of Public Policy and a Joint Faculty Member of Oak Ridge National Laboratory. She joined Georgia Tech in 2006 after 22 years at Oak Ridge National Laboratory, where she managed the Lab's research on energy efficiency, renewable energy, and the electric grid.

Dr. Brown's current research examines the clean energy transition – modeling and evaluating the impact of technology advances, supporting policies, and their social, behavioral, and economic consequences, with a special emphasis on equity. Her two most recent books are *Empowering the Great Energy Transition* (Columbia University Press, 2019) and *Fact and Fiction in Global Energy Policy* (Johns Hopkins University Press, 2016). She has authored more than 250 publications and contributed to the 2007 Intergovernmental Panel on Climate Change assessment reports for which the IPCC shared the 2007 Nobel Peace Prize. Her work has had significant visibility in the policy arena as evidenced by her briefings and testimonies before state legislative and regulatory bodies, Committees of both the U.S. House of Representatives and Senate, and international organizations.

Dr. Brown co-founded the Southeast Energy Efficiency Alliance and chaired its Board of Directors for several years. She has served on the Boards of the American Council for an Energy-Efficient Economy and the Alliance to Save Energy, and was a commissioner with the Bipartisan Policy Center. She has served on eight National Academies committees and serves on three Editorial Board: *Energy Policy*, *Energy Efficiency*, and *Energy Research and Social Science*. She served two terms (2010-2017) as a Presidential appointee and regulator on the Board of Directors of the Tennessee Valley Authority, the nation's largest public power provider. From 2014-2018 she served on DOE's Electricity Advisory Committee, where she led the Smart Grid Subcommittee.

Previous Employment & Education

Oak Ridge National Laboratory: Director of Engineering Science and Technology Division – 300 staff (2005-2006); Director, Deputy Director and Group Leader (1984-2004) of the Energy Efficiency, Renewable Energy, and Electric Grid Program (\$130 million annual budget).

Tenured Associate Professor of Geography, Univ. of Illinois (1983-84) (Assistant Professor 1977-83).

Lecturer, Department of Geography and Geology, Ohio Wesleyan University (1976-77).

Teaching Assistant and University Fellow, Ohio State University (1973-76).

Research Analyst, Connecticut Department of Environmental Protection (1973).

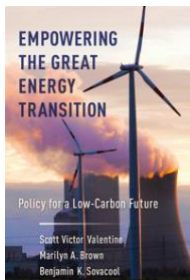
Ph.D., The Ohio State University, Geography; minor in Quantitative Methods, 1977 (Dissertation: The Role of Public and Private Agencies in the Diffusion of Innovations).

M.R.P., University of Massachusetts, Regional Planning, 1973.

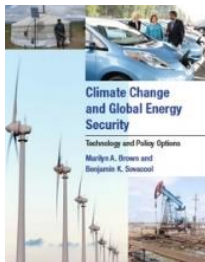
Direct Testimony of Dr. Marilyn A. Brown
 Southern Alliance for Clean Energy & Southface Energy Institute, Inc.
 Georgia PSC, Docket No. 44280
 B.A., Rutgers University, Political Science (major), Mathematics (minor), 1971.
 C.E.M. (Certified Energy Manager), Association of Energy Engineers, 2003-2024.
 2012 Institute of Nuclear Power Operations, at the Goizuetta Business School at Emory University.

Books and Special Issues of Journals

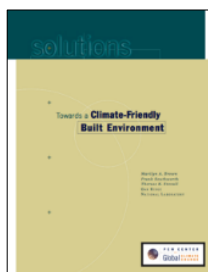
S.V. Valentine, M.A. Brown, and B. K. Sovacool (2019) [*Empowering the Great Energy Transition: Policy for a Low-Carbon Future*](#) (Columbia University Press) 2019.



Brown, M.A., & Sovacool, B.K. (2011). *Climate change and global energy security: technology and policy options*. MIT Press.



Brown, M. A., Southworth, F. & Stovall, T. K. (2005). [*Towards a climate-friendly built environment*](#). Pew Center on Global Climate Change.



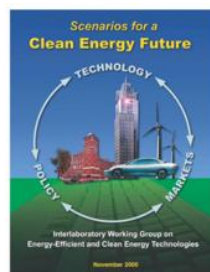
Sovacool, B.K., M.A. Brown, & S.V. Valentine (2016). *Fact and fiction in global energy policy: fifteen contentious questions*. John Hopkins University Press.



Brown, M.A., F. Southworth, & A. Sarzynski (2008). [*Shrinking the carbon footprint of metropolitan America*](#). Brookings Institution.



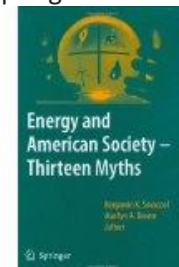
M. A. Brown, W. Short and M. D. Levine (eds.) (2000) [*Scenarios for a Clean Energy Future*](#). Google Books. + Special Issue of *Energy Policy* in 2001.



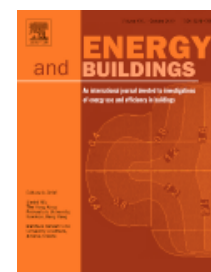
Brown, M.A., & Y. Wang (2015). *Green savings: how policies and markets drive energy efficiency*. ABC-CLIO.



Sovacool, B.K., & Brown, M.A. (Eds.). (2007). *Energy and American Society—Thirteen Myths*. Springer.



M. A. Brown and K. Keating (eds) (1989) Special Issue of *Energy and Buildings* devoted to *The Hood River Conservation Project*, 13(1).



Principal technical society memberships, activities and accomplishments:

- Member, U.S. Department of Energy’s Electricity Advisory Committee, two terms: 2014-2018.
- Served on nine committees, panels, and boards of the National Academy of Sciences:
 - ✓ Data, Metrics, and Analytic Methods for Assessing Equity Impacts of Surface Transportation Funding Programs, 2021-2024
 - ✓ Geographical Sciences Committee, 2016-2019
 - ✓ Committee on Urban Sustainability, 2014-2016
 - ✓ Board of Energy and Environmental Systems, 2006-2012 (two terms)
 - ✓ Panel on Redesigning the Commercial Buildings and Residential Energy Consumption Surveys of the Energy Information Administration, 2010-2012
 - ✓ America’s Climate Choices, 2008-2011
 - ✓ Limiting the Magnitude of Climate Change Panel (Co-chair), 2008-2011
 - ✓ America’s Energy Choices: Energy Efficiency, 2007-2009
 - ✓ Alternatives to the Indian Point Nuclear Plant, 2004-2007.
- Ambassador for Clean Energy, Education and Empowerment (C3E), designated by the U.S. Department of Energy in 2012 and announced at the first Clean Energy Ministerial in London, 2012-2021.
- U.S. Presidential Appointee (U.S. Senate confirmed): Board of Directors, Tennessee Valley Authority, two terms: 2010-2018.
- Member, Advisory Committee, U.S. Department of Energy’s Energy Efficiency and Renewable Energy Industrial Technologies Program, 2008-2009.
- Elected to the Policy Council, Association for Public Policy Analysis and Management, 2006-2009.
- Appointed, National Commissioner on Energy Policy, Bipartisan Policy Center, Washington, DC. 2002-2009.
- Member, U.S. Environmental Protection Agency, Board of Scientific Counselors, Office of Research and Development, 1996-2000.
- Elected National Councilor of the Association of American Geographers, 1988-1991
- National Science Foundation: Review Panel Member, Geography and Regional Science Division, 1984-1986

Professional Recognition (Honors and Awards)

- Distinguished Professor, [Georgia Tech Class of 1934 Award](#), 2022
- [World Citizen Prize in Environmental Performance](#), by the Association for Public Policy Analysis and Management (APPAM) 2021
- Regents’ Professor, Georgia State Board of Regents, 2017-2023.
- Election to the National Academies of Science and Engineering, 2020
- “Champion of Energy Efficiency in Industry,” American Council for an Energy-Efficient Economy, 2017.
- Alliance to Save Energy [“Pioneer” Award to TVA](#) for its Energy Efficiency Planning Model, 2016
- Brook Byers Chaired Professor in Sustainable Systems, 2014-2023.
- “Who’s Who in Sustainability,” Atlanta Business Chronicle, 2013.
- Planning Committee, 2016-2018, U.S. Department of State, Sixth Intergovernmental Panel on Climate Change (IPCC).
- Review Editor, 2011-2014, U.S. Department of State, Fifth Intergovernmental Panel on Climate Change (IPCC), *Climate Change 2014: Mitigation of Climate Change*.
- Co-Author Intergovernmental Panel on Climate Change Working Group III Assessment Report on

Direct Testimony of Dr. Marilyn A. Brown
Southern Alliance for Clean Energy & Southface Energy Institute, Inc.
Georgia PSC, Docket No. 44280

Mitigation of Climate Change, Chapter 6. Authors of this report were co-recipients of the 2007 Nobel Peace Prize.

- Southface Energy Institute Award of Excellence “In recognition of exemplary leadership and a lifetime of advocacy for energy efficiency,” 2010.
- Vice-Chair, 2006, U.S. Department of Energy, U.S. Government Review of the Second Order Draft IPCC Report: *Climate Change 2007: Mitigation of Climate Change*.
- Anderson Medal of Applied Geography, Association of American Geographers, 2003, and 2008 Anderson Medal distinguished lecture.
- Co-recipient, U. S. Department of Energy Research Partnership Award, presented to Southwire Company and the ORNL Superconductivity Program for Electric Systems for the 3M Coated Conductor Development Project, 2001
- Commendation from Energy Secretary Hazel R. O’Leary for publication of “Weatherization Works,” December 1993.
- “Champion of Energy Efficiency,” American Council for an Energy-Efficient Economy, for co-leading the five-laboratory study titled “Scenarios of U.S. Carbon Reductions,” which President Clinton acknowledged as a basis for signing the 1997 Kyoto Protocol, 1998.

Awards from Oak Ridge National Laboratory: (1) co-leading the five-laboratory study titled “Scenarios of U.S. Carbon Reductions,” November 1997, (2) leading the “National Evaluation of DOE’s Weatherization Assistance Program,” July 1993; (3) Citation for Research Excellence in 1989; (4) Significant Event Award in 1997 for the study “Technology Opportunities to Reduce U.S. Greenhouse Gas Emissions,” and (5) Small Business Program Advocate Award 2002.

Corporate Honoree, YWCA Tribute to Women, 1994; Award for Distinguished Contribution to “Science Management and Policy Implementation,” American Women in Science, May 1992; Gold Medal Award issued by the Technology Transfer Society for the best paper published in the 1989-1990 *Journal of Technology Transfer*; Best Paper Award, The 12th Annual Meeting & International Symposium of the Technology Transfer Society, 1987; C. C. Huntington Memorial Award, 1976, an award made periodically by The Ohio State University, Department of Geography to “outstanding graduate students”; University Fellow, The Ohio State University, 1973-77.

Congressional and Regulatory Briefings and Testimonies

- Testimony before the Georgia Public Service Commission on Georgia Power’s 2022 Integrated Resource Plan (Docket 44160) and Demand Side Management Plan (Docket 44161). 5/26/2022. <https://psc.ga.gov/search/facts-document/?documentId=189985>.
- Briefing to Assistant Secretary Bruce J. Walker, Office of Electricity, U.S. Department of Electricity, February 20, 2018, on activities of the DOE’s Electricity Advisory Committee’s Smart Grid Subcommittee.
- Testimonies to the Florida Senate Committee on Communications, Energy, and Public Utilities and the Florida House Energy & Utilities Subcommittee, on “Renewable Energy in the South,” February 21-22, 2011.
- Testimony to the U.S. Senate Environment and Public Works Committee on “Priorities for the Tennessee Valley Authority,” 2010.
- Congressional briefing hosted by the American Chemical Society’s Science and Congress Project; Co-hosted by Rep. Gabrielle Giffords (D-AZ) and Rep. Ralph Hall (R-TX), December 15, 2008
- Congressional briefing in a Hearing on [“Can a National Renewable Portfolio Standard Increase Energy Security, Reduce Emissions, and Lower Costs,”](#) Sponsored by the Environment and Energy Study

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Institute, July 11, 2007,

- Energy Efficiency Workshop for staff of the U.S. House of Representatives Committee on Energy and Commerce Committee, July 2007.
- Testimony to North Carolina Legislative Commission on Global Climate change, “Discussion of the technology options related to global climate change by sector,” April 25, 2006.
- Expert Witness on Climate Change Technologies. Testimony before the Energy Subcommittee of the U.S. House of Representatives’ Committee on Science. Hearing on November 6, 2003.
- Expert Witness, Testimony before the U.S. Senate Committee on Environment and Public Works. Hearing on “Global Climate Change and Issues Related to Reducing Net Greenhouse Gas Emissions.” May 2001.

Advisory Committees and Boards

Recent/Current Advisory Committees and Boards: Oak Ridge Associated Universities (2021-2014); DOE Electricity Advisory Board, 2014-2018; Member, Research Advisory Council, Electric Power Research Institute, 2010-2012, U.S. Department of Energy Peer Review Committee for the Industrial Technologies Program, 2008-2009; Lawrence Berkeley National Laboratory Energy and Environmental Division, 2009; Natural Resources Defense Council’s Project on Climate Mitigation Modeling, 2008-2009; Pew Center on States’ Committee on “Green Scorecards”, 2008-2009; Harvard University’s Energy Research Committee, 2008-2009.

Selected Past Advisory Committees: University of Kansas, Transportation Research Institute, 2006-2007; World Energy Engineering Congress, 2004-2006; Energy and Environmental Technologies Division, Lawrence Berkeley National Laboratory, 1998-99; Iowa Energy Center (Chair), 1998-99; University of Tennessee’s Energy, Environment and Resources Center, 1996-98; New York State Energy Research and Development Authority, 2000.

Selected Research (Principal investigator on research projects > \$25 million)

PI, 2022-2023, Sierra Club, “Causal Analysis of Energy Burdens of Black Households”
 PI, 2019-2022, Ray C. Anderson Foundation, “Georgia Carbon Drawdown.”
 PI, 2018-2022, Philanthropic gift, “Sustainable Energy and Environmental Management.”
 PI, 2016-2023, ORNL, Joint Faculty Appointment
 PI, 2017-2018, Natural Resources Defense Council. “Biomass Economics.”
 PI, 2015-2017, Energy Foundation. “Energy Efficiency and Clean Energy Jobs.”
 PI, 2016-2018, U.S. Department of Energy, Support for Mission Innovation and the Quadrennial Energy Review.
 PI, 2006-2018, ORNL, “Core University Liaison” for Georgia Tech; 2006-2016
 PI, 2014-2015, Strategic Energy Institute, “Future of the Electric Grid in the Southeast”.
 PI, 2013, Southface Energy Institute and Energy Foundation, “Expanded Capacity for Modeling Energy Efficiency in the Southeast”.
 Co-PI with Elsa Reichmanis, 2011-2018. National Science Foundation. Integrative Graduate Education and Research Training (IGERT) award to enhance multidisciplinary training in the skills required for conducting research in energy science, technology and policy, with a focus on advanced materials.
 PI, 2009-2016, U.S. Department of Energy, “Behaviorally Energy-Efficiency Based Policies”. Uses the National Energy Modeling System in conjunction cost-benefit analysis to evaluate alternative policy options.
 PI, 2010-2012, Oak Ridge National Laboratory, “Eastern Interconnection Demand-side Resource Assessment”.
 PI, 2009-2011, Energy, Turner and Kresge Foundations, “Integrated Analysis of the Cost and Availability of Supply- and Demand-Side Electricity Resources in the Southeast”.

Direct Testimony of Dr. Marilyn A. Brown

Southern Alliance for Clean Energy & Southface Energy Institute, Inc.

Georgia PSC, Docket No. 44280

Co-PI with Jan Youtie, 2008-2009. Georgia Board of Regents, *Energy and Environmental Workforce: Supply and Demand in Georgia*, \$20,000.

PI, 2007-2008, Southeast Energy Efficiency Alliance and Appalachian Regional Commission, *Potential for Energy Efficiency Improvements in the Appalachian Region*.

PI, 2007-2008, Brookings Institution, *Shrinking the Carbon Footprint of Metropolitan America*.

PI, 2007-2008, Sloan Center grant, *Potential Impacts of Energy and Climate Policies on the U.S. Pulp and Paper Industry*.

PI, 2006-2008, U.S. Department of Energy, *Development of a National Strategy for the Deployment of Greenhouse Gas-Reducing Technologies*.

PI, 2005-2006, U.S. Department of Energy, *R&D Portfolio Review* of the Multi-agency Climate Change Technology Program.

PI, Pew Center on Global Climate Change. 2004. *Towards a Climate Friendly Built Environment*.

PI, Cooperative program on technology transfer from National Laboratories with the Education and Research Consortium of the Western Carolinas, 2004-2006.

Co-PI, U.S. Department of Energy. 1996-2001. Two multi-laboratory studies:

- *Scenarios of U.S. Carbon Reductions: The Potential Impact of Energy-Efficient and Low-Carbon Technologies*. President Clinton cited this study as providing the support that enabled the U.S. Administration's support for the U.S. goal for greenhouse gas reductions proposed at the 1997 Kyoto summit on global climate change. https://digital.library.unt.edu/ark:/67531/metadc694703/m2/1/high_res_d/563139.pdf
- *Scenarios for a Clean Energy Future*. When published in November 2000, this was the most detailed scenario analysis of potential U.S. carbon emissions reductions ever funded by the U.S. government. It provided a foundation of analysis for the U.S. discussions at the 6th Conference of the Parties to the United Nations Framework Convention on Climate Change in the Hague in November 2000. <https://www.nrel.gov/docs/fy01osti/29379.pdf>

Courses Taught

Energy Policy and Technology (co-listed with Industrial Systems Engineering); Utility Policy and Regulation; Energy Policy and Markets; Materials for Energy Systems and Energy Policy (cross-listed with Mechanical Engineering); Environmental Finance; Economic, Urban, Regional, Environmental, and Social Geography; Statistical Techniques for the Social Sciences; Urban and Environmental Geography Seminars; Social and Environmental Indicators; and Technology Management and Diffusion.

Consulting Activities

RTI International, Design and Evaluation of Demand-Side Management Programs in Abu Dhabi, United Arab Emirates, 2008-2009.

GE-Energy Services, GE Energy Certificate Program in Business Management of Energy Technologies, 2008.

Pew Charitable Trusts, Assessment of past projects and future directions in environmental and climate change areas, 1998.

Faculty Research Development Program, West Virginia University Regional Research Institute, 1994-96.

Evaluation of California demand-side management programs. California Public Utilities Commission and Southern California Edison Company, 1994-95.

Evaluation of U.S. demand-side management programs. London Economics, Ltd., 1993-94; Program evaluation and strategic planning. New York State Energy Research and Development Authority, 1989-96; Cook County State's Attorney's Office, 1984. Testified before the Illinois Public Utility Commission on performance

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contracting approaches to financing energy efficiency improvements.

Elected Offices, Editorial Boards, and Other Professional Activities

Co-Founder and Chair, Board of Directors, Southeast Energy Efficiency Alliance, 2006-2009.
Commissioner, National Commission on Energy Policy, 2002-2009.
Elected Chair, Energy and Environment Specialty Group, Association of American Geographers, 1986 to 1988 and 1994 to 1996. Elected Director of two other AAG Specialty Groups.
Provided briefings to the President's Council of Economic Advisors, Office of Science and Technology Policy, the Office of Management and Budget, committees of the U. S. House of Representatives and Senate, committees of the National Association of Regulatory Utility Commissioners, and several State Public Utilities Commissions, the New York Independent System Operator, and the North Carolina Commission on Climate Change.
Served on an EPA Advisory Committee overseeing the development of Conservation Validation Protocols (1993) and served as a member of the review panel for EPA's Environmental Technology Initiative (1995).
Co-Editor: Energy and Environment, newsletter of the Energy and Environment Specialty Group, Association of American Geographers, 1991-92 and 1994-96; and Women in Geography, newsletter of the Committee on the Status of Women in Geography, Association of American Geographers, 1983-84. Initiated an Urban Geography Dissertation Competition, which continues to attract nationwide participation. Participated as a member of the Long-Range Planning Committee, Urban Geography Specialty Group, 1985-86. Member of the planning committee for the 1993 National Meeting of the AAG. Member, Publications Committee, Association of American Geographers, 1983-86.
Editorial Boards: Journal of Energy Efficiency, 2008-present; Journal of Technology Transfer, 1997-99 and 2002-2006; Applied Geography Studies, 1996-98; Economic Geography, 1991-95; Home Energy, 1990-95; The Professional Geographer, 1987-90; and Annals of the Association of American Geographers, 1984-87.
Board of Directors, Alliance to Save Energy, 1998-2009; American Council for an Energy-Efficiency Economy, 2001-2009; Home Energy, 1995-2003.

Seminars and Presentations

Seminars and presentations at universities, research institutes, and government agencies in 40 of the U.S. states including: the National Renewable Energy Lab, Los Alamos National Lab, Oak Ridge National Lab, Argonne National Lab, Brookhaven National Lab. the National Academy of Sciences, National Academy of Engineering, Clemson University, Vermont Law School, Vanderbilt University, University of Georgia, Stanford University, Duke University, the University of Alabama, Northern Illinois University, the University of California-Santa Barbara, University of California-Davis, the University of Illinois, Indiana University, the Ohio State University, the University of Iowa, the University of Tennessee, Arizona State University, Pennsylvania State University, Michigan State University, Johns Hopkins University, Rutgers University, the Massachusetts Institute of Technology, Stanford University, University of Central Florida, Texas A&M University, Emory University, Iowa State University, and the University of Kentucky.

The impact of my work has been felt across the globe as the result of active international consultations and collaborations conducted in affiliation with universities, research institutes, and government agencies in numerous countries. Many of these affiliations involved visits of several weeks or a month including government workshops, academic lectures, and interviews with local press focused on the mechanics and importance of implementing policies and technologies to promote a clean energy transition. Consultations were conducted and talks were given at, for example at: King Abdullah University of Science and Technology, Oxford University, the Tyndall Center for Climate Change at Newcastle University, Imperial College of London, Warwick University,

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the Science Policy Research Unit at the University of Sussex, the Paris School of International Affairs, the Potsdam Institute for Climate Impact Research, the University of Groningen, IEA-Paris, and the IEA Center for the Analysis and Dissemination of Energy-Efficient Technologies, Aarhus University, Norwegian University of Science and Technology, Copenhagen University, the Korea Advanced Institute of Science and Technology, the Korea Atomic Energy Research Institute, the University of Kyushu, Nagoya University, City University of Hong Kong, Beijing Institute of Technology, Tianjin University, and the National University of Singapore.

Selected seminars, presentations, videos, and podcasts:

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 “First Mover Advantages Amid a Clean Energy Boom” 9th
 “Geospatial Dimensions of Energy Inefficiency and Equity”
 Geographical Science Committee, National Academy of Sciences
 (6.11.2020)

International Workshop on Advances in Cleaner Production (IWACP)
 Melbourne, Australia (5.26.2020)

“Green Innovation for Sustainable Growth” Global Innovative
 Growth Forum, Ministry of Economy and Finance, Republic of Korea
 (12.9.2020)

“Empowering the Great Energy Transition While Fossil Fuels are Still
 Abundant: The U.S. Challenge,” Oxford University, June 18, 2019,
[https://www.energy.ox.ac.uk/wordpress/wp-
 content/uploads/2019/06/Empowering-the-great-energy-transition-
 while-fossil-fuels-are-still-abundant-The-U.S.-challenge.pdf](https://www.energy.ox.ac.uk/wordpress/wp-content/uploads/2019/06/Empowering-the-great-energy-transition-while-fossil-fuels-are-still-abundant-The-U.S.-challenge.pdf)

“Vulnerability of U.S. Infrastructure to Coastal Flooding,” National
 Academies of Sciences, December 6, 2018.

“EVs + Renewables: A Merger of Complementary Adaptation
 Strategies,” Geography 2050: American Geographical Society, Fall
 Symposium on Energy Adaptation Strategies, Columbia University,
 November 16, 2018.

“Technologies and Policies for a Sustainable Energy Future,” 2017
 Energy Infrastructure Symposium, Boston,
 November 13, 2017,
[https://cepl.gatech.edu/sites/default/files/attachments/Borealis-11-
 13-17%20Brown.pptx](https://cepl.gatech.edu/sites/default/files/attachments/Borealis-11-13-17%20Brown.pptx).

“Energy and Society”, Tyndall Center Assembly Day, Newcastle upon
 Tyne, England, September 12, 2017.

“Shifting the Energy Mix in a post-Paris World”, American
 Geophysical Union 2016 Fall Meeting, San Francisco, CA, Dec. 13,
 2016.

“Progress in Energy and Carbon Management in Large U.S.
 Metropolitan Areas,” International Conference on Applied Energy,
 Abu Dhabi, UAE, March 30, 2015.

“Smart Grid Technologies and Policies for a Clean Energy
 Transition”, Symposium on Energy Transition Challenges, City
 University of Hong Kong, May 20, 2014.

Selected Podcasts and Videos

[Localized Roadmaps to Fight the Climate Crisis](#),
 National Academies of Sciences, April 30, 2022

The Forecast for Solar, [Podcast](#) with energy
 leaders on February 16, 2022

[Podcast about the transition to clean energy
 technologies](#), with Commissioner Tim Echols
 on March 13, 2021

[Climate Reporting Master Class](#) March 18,
 2021

[Solve Climate by 2030](#) April 9, 2021

[Guiding Principles for Sound Energy Policy](#),
 February 10, 2021

[Building Electrification: Politics-Economics-
 Infrastructure](#) July 15, 2020

[Weather Geek Interview on Drawdown
 Georgia](#), April 22, 2020

[The Future with a Green New Deal](#), October
 30, 2019.

[Vulnerability of U.S. Energy Infrastructure to
 Coastal Flooding](#), December 6, 2018.

[Energy Adaptation Strategies](#), American
 Geographical Society, Nov. 16, 2018.

[Enabling the Great Energy Transition](#), Fries
 Lecture, October 18, 2018.

[Integrating Distributed Resources into the U.S.
 Power System](#), November 3, 2017.

“Is energy efficiency a worthwhile investment?”
 September, 2016.

“[Made in Kentucky: Energy Efficiency Jobs and
 Opportunities](#)” 2015.

“[Perspectives on Energy Efficiency](#)” National
 Press Club, May 2, 2014.

[Technologies and Policies for a Sustainable
 Energy Future](#), TedX Talk. 2014.

[C3E Women in Clean Energy Panel Discussion](#)
 2015.

[C3E Women in Clean Energy on Energy
 Decarbonization](#) 2016.

Book Debate: [Climate Change and Global
 Energy Security](#).

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“Sustaining the City: Understanding the Role of Energy and Carbon Dioxide Emissions in Sustainable Development in Major Metropolitan Areas”, ACEEE, Monterey, CA, August 20, 2014.

“Moving Technologies from the Lab to the Marketplace” C3E Women in Clean Energy, MIT, Cambridge, MA, September 20, 2013.

“Demand-side Management Policies and Alternative Futures for the Electricity Sector” UK Energy Research Center Summer School, Warwick University, Coventry, England, June 9, 2013.

“Evaluating a Federal Cogeneration Policy: Could it Strengthen U.S. Competitiveness and Generate Energy Jobs?” *Annual Meeting of the U.S. Clean Heat and Power Association*, October 7, 2011.

https://cepl.gatech.edu/sites/default/files/attachments/BROWN_USCHPA_FINAL.pdf

“Competing Dimensions of Energy Security,” *POLINARES Workshop on Energy Security*, Paris School of International Affairs, June 1, 2011.

“Federalism and Polycentric Governance,” *National Academy of Arts & Sciences Workshop*, Washington, DC, May 20, 2011. <http://www.amacad.org/events/alternativeEnergy/brown.pdf>.

“Setting the Stage for a Low-Energy Building Stock,” *ACEEE Forum*, Washington, DC, March 7, 2011, <http://www.aceee.org/files/pdf/conferences/30th/building/Brown.pdf>

“Nuclear Energy and the Transition to a Sustainable Energy Future,” *Women in Nuclear Conference*, Oak Ridge National Laboratory, February 8, 2011.

“Renewable Energy in the South,” *Renewable Energy in the South*,“ Southeast U.S./Japan Annual Meeting, Nashville, TN, October 18, 2010.

“Science, Society, and Sustainable Economic Growth,” U.S.–European Summit, Washington, DC, September 28, 2010.

“Limiting the Magnitude of Future Climate Change,” National Academy of Engineering Convocation, Washington, DC, April 19, 2010.

“Energy Efficiency in the South,” Congressional briefing sponsored by EESI, Washington, DC, April 12, 2010.

“Shrinking the Carbon Footprint of Metropolitan America,” *Toward Low-Carbon Cities: Understanding and Analyzing Urban Energy and Carbon*, Nagoya, Japan, February 16-18, 2009

“The Role of Energy Efficiency in a Federal Renewable Energy Standard,” EUCI RPS Symposium, Washington, DC, March 27, 2008.

“Including Efficiency: A National Sustainable Energy Portfolio,” Congressional briefing sponsored by EESI, July 11, 2007. http://www.eesi.org/files/Marilyn_Brown.pdf

“Feasible Efficiency Improvements, Real World Constraints, and Carbon Emission Implications,” U.S. House of Representatives Committee on Energy and Commerce’s Workshop on Energy Efficiency. March 2, 2007.

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“Energy Efficiency: Progress and Opportunities,” at the Global Climate and Energy Project Symposium at Stanford University, October 1, 2007.

http://gcep.stanford.edu/pdfs/kUXNHroC3cAssx6wJoz_Mg/Brown-20071001-GCEP.pdf

“Towards a Climate-Friendly Built Environment” June 2005, National Press Club, Washington, DC.

I have served on the planning committees for many national and international conferences including the 1989, 1991, 1993, 1995, 1997, and 1999 National Energy Program Evaluation Conferences, the 1991 and 1992 Affordable Comfort Conferences, and the 1994, 1996, and 2010 Summer Study on Energy Efficiency in Buildings organized by the American Council for an Energy-Efficient Economy. I co-chaired the 1998 Summer Study on Energy Efficiency in Buildings, with Helmut Feustel of Lawrence Berkeley National Laboratory.

Selected other presentations: Plenary panelist at the 2006 National Conference on Science, Policy and the Environment, Illinois Energy Forum, International Energy Agency, National Association of Regulatory Utility Commissioners, Electricity Consumers Resource Council, Electric Power Research Institute, and the National Institute of Standards and Technology.

Chair or member of numerous graduate committees while at Georgia Tech.

Masters students advised and their current affiliations (partial list):

Lindsay Averett, Oglethorpe Power
Aline Banboukian, Georgia Tech PhD student
Elise Logan, Booz Allen Hamilton
Nancy McGee, Deloitte
Jess Chandler, EMI Consulting
Matt Cox, The Greenlink Group
Fanny Guezennec, EcoAct Corporation
Elizabeth Noll, Natural Resources Defense Council
Dong-Yeon Lee, Argonne National Laboratory
Cecelia Shuttters, U.S. Green Building Council
Ben Staver, ICF International
Jeff Hubbs, Emory University
Daniel D’Arcy, U.S. Environmental Protection Agency
Usayd Casewit, World Bank
Alyson Laura
Valentina Sanmiguel

PhD students advised (N=19): Susan Macey, Paul Rollinson, Jess Chandler, Youngsun Baek, Nilgun Atamturk, Joy Wang, Matt Cox, Ben Deitchman, Yu Wang, Anmol Soni, Majid Ahmadi, Xiaojing Sun, Yeong Jae Kim, Gyungwon Kim, Alexander Smith, Shan Zhou, Yufei Li, Oliver Chapman, Snehal Kale, Majid Ahmadi.

Member of PhD Committee (N=6 SPP, 16=other disciplines): Mohan Taruga (Public Policy), Elena Harari (Public Policy), Diran Soumoni (Public Policy), Caroline Golin (Public Policy), Ben Jordan (Public Policy), Marty Sung (City and Regional Planning), Ji Hyun Kim (Architecture), Dong Gu Choi (Industrial Systems Engineering), Harjeet Johal (Electrical and Computational Engineering), Marcelo Sandoval (Electrical and Computational Engineering), Fei Zhao (Architecture), Brent Weigel (Civil and Environmental Engineering), Anthon Sonnenberg (Civil and Environmental Engineering), Dieudonne Batsy (Montreal Polytechnic), Jenna McGrath

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(Public Policy), Fikret Atalay (Civil and Environmental Engineering), Cal Abel (Mechanical Engineering), Jan Yunchen (Civil and Environmental Engineering), Hongyang Zou (College of Management and Economics, Tianjin University), Zixing Wang (Industrial and Systems Engineering), Ross Bepler (Public Policy).

At the University of Illinois Geography Department, I served on the Campus-wide Instructional Computer Use Committee, was a member of the Statistics Program Faculty for three years, and served on the Board of Directors of the Social Science Quantitative Laboratory for six years.

Current or Recent Organizational Memberships

Association of Energy Engineers

Association of American Geographers

Association for Public Policy Analysis and Management

Referee Activities

Reviewed articles and monographs for the following publications: Applied Energy, Urban Studies, Environmental Research Letters, Energy Research and Social Science, Journal of Energy Efficiency, Climate Change, Journal of Regional Studies, Applied Geography, Technology Transfer Journal, Annals of the Association of American Geographers, Science, Energy Policy, Journal of Regional Science, International Regional Science Review, The Professional Geographer, Environment and Planning, Urban Geography, Resource Papers of the AAG, Political Geography Quarterly, Women's Studies International Forum, Journal of Geography, Economic Geography, Geographical Analysis, Applied Psychological Measurement, Urban Studies, Growth and Change, Environmental Science & Technology, Current Opinion in Environmental Sustainability, and Social Science Quarterly.

Reviewed research proposals for: the New York State Energy Authority, the Regional Research Institute of the West Virginia University, DOE, EPA, NIH, NSF, and the Rockefeller Foundation.

Manuscripts under Development

"Drawdown Georgia Business Compact: A Partnership Advancing Collective Business Action for Climate Mitigation." Draft book chapter.

"Do Coal Plant Closures Serve Environmental Justice to Black Communities? Health Outcomes from a Natural Experiment" by Ghodeswar, Archana and Marilyn A. Brown. Draft journal article.

"Co-adoption of Climate Technologies, Submitted to *Energy Research and Social Science*.

"What Return-on-Investment is Required for Household Electrification? A New Approach to Willingness to Pay," Draft journal article.

Manuscripts under Review and Forthcoming

Liu, Xi; Du, Huibin; Tang, Ling; Bo, Xin; Li, Jiashuo; Zuo, Jian; Brown, Marilyn; Jia, Min; Feng, Kuishuang, "Relocating industrial plants delivers win-win emission-reduction benefits to origin and destination regions" *Environmental Science & Technology*, forthcoming.

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Brown, M.A. et al., Jasmine Crowe, John Lanier, Michael Oxman, Roy Richards, Jr., L. Beril Toktay. 2023.

“Drawdown Georgia Business Compact: A Partnership Advancing Collective Action for Climate Mitigation” forthcoming book chapter.

Dong-Yeon Lee; Alana Wilson; Melanie H. McDermott; Robert Kaufmann; Raphael Isaac; Benjamin Sovacool; Cutler Cleveland; Bo Liu; Margaret Smith; Marilyn Brown; Eric Wood; Jacob Ward; Jeff Gonder, *Quantifying Inequality in the Distribution of Electric Vehicle Adoption and Charging Infrastructure in the United States*, under review by *Energy Policy*.

Anmol Soni, Marilyn A. Brown, Benjamin K. Sovacool, “Values, actions, and opinions for low-carbon mobility: Assessing public support for Electric Vehicles in the Nordic region” under review.

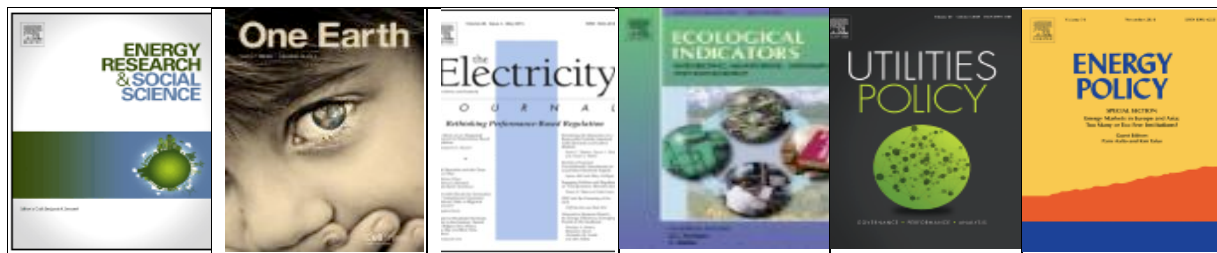
Journal Articles (N=141)

- Brown, M.A., R. Tudawe, and H. Steimer. 2022. Carbon drawdown potential of utility-scale solar in the United States: Evidence from a case study of Georgia. *Renewable and Sustainable Energy Reviews* 161 (June): pages 112318. <https://doi.org/10.1016/j.rser.2022.112318>
- Matisoff, Daniel C., Marilyn A. Brown, and Snehal Kale. 2022. “Modernizing the Energy Infrastructure at Federal Facilities: Should Utilities Play a Bigger Role?” *Electricity Journal*, Volume 34 (2), March. <https://doi.org/10.1016/j.tej.2022.107078>
- Brown, M.A., J. Hubbs, X.V. Gu, and M.-K. Cha. 2021. Rooftop Solar for All: Closing the Gap Between the Technically Possible and the Achievable Potentials. *Energy Research and Social Science* 81 (November), pages 102285. <https://doi.org/10.1016/j.erss.2021.102203>
- Brown, Marilyn A. and Valentina Sanmiguel Herrera (2021), “Combined Heat and Power as a Platform for Clean Energy Systems,” *Applied Energy*, Vol. 304, December, 117686 <https://doi.org/10.1016/j.apenergy.2021.117686>
- Brown, Marilyn A. and Oliver Chapman (2021), “The Size, Causes, and Equity Implications of the Demand-Response Gap”, *Energy Policy*, 158 (November), pages 112533. <https://doi.org/10.1016/j.enpol.2021.112533>
- Brown, Marilyn A., Puneet Dwivedi, Sudhagar Mani, Daniel Matisoff, Jacqueline E. Mohan, Jeffrey Mullen, Michael Oxman, Rodgers, Richard Simmons, Blair Beasley, Lalith Polepeddi (2021). “A Framework for Localizing Global Climate Solutions and their Carbon Reduction Potential,” *Proceedings of the National Academy of Sciences*, 118 (31); <https://doi.org/10.1073/pnas.2100081118>
- Romero-Lankao, Patricia; Wilson, Alana; Miller, Clark; Sperling, Joshua; Sovacool, Benjamin; Zimny-Schmitt, Daniel; Gearhart, Chris; Muratori, Matteo; Bazilian, Morgan; Southworth, Frank; Zuend, Daniel; Young, Stanley; Wood, Eric; Brown, Marilyn; Arent, Douglas (2021), “Of Actors, Cities and Energy Systems: Analyzing the Transformative Potential of Urban Electrification,” *Progress in Energy*, Volume 3. <https://doi.org/10.1088/2516-1083/abfa25>
- Brown, Marilyn A., Blair Beasley, Fikret Atalay, Kim M. Cobb, Puneet Dwivedi, Jeffrey Hubbs, David M. Iwaniec, Sudhagar Mani, Daniel Matisoff, Jacqueline E. Mohan, Jeffrey Mullen, Michael Oxman, Daniel Rochberg, Michael Rodgers, Marshall Shepherd, Richard Simmons, Laura Taylor, L. Beril Toktay.

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(2021) "Translating a Global Emission-Reduction Framework for Subnational Climate Action: A Case Study from the State of Georgia," *Environmental Management*. 67: 205-227. <https://doi.org/10.1007/s00267-020-01406-1>.

- Jan, Yunchen, Marilyn A. Brown, Deyou Yu, and John Crittenden. (2021) "Policy Incentives and Social Cost of Emissions for Promoting Decentralized Energy Production: A Life Cycle Cost Analysis," *Journal of Cleaner Production*, 282, February, 125394.
- Brown, Marilyn A., 2021. "Could the U.S. Become a Role Model for Electricity Decarbonization?" *One Earth*, <https://doi.org/10.1016/j.oneear.2021.04.004>,
- Brown, M.A., A. Soni, M.V. Lapsa, K.A. Southworth, M. Cox. (2020) "High Energy Burden and Low-Income Energy Affordability: Conclusions from a Literature Review," *Progress in Energy*, Vol. 2 (4), <https://dx.doi.org/10.1088/2516-1083/abb954>
- Brown, Marilyn A., Anmol Soni, Ameet D. Doshi, and Charlotte King. (2020) "The Persistence of High Energy Burdens: A Bibliometric Analysis of Vulnerability, Poverty, and Exclusion in the United States," *Energy Research and Social Science*, Vol. 70, September. <https://doi.org/10.1016/j.erss.2020.101756>
- Brown, Stephen P.A, Marilyn A. Brown, Reinhard Madlener, Stephen Thomas, Peng Zhou, Carlos Henggeler Antunes, Sonia Yeh, Huibin Du, and Stephane Goutte. (2020). "The continuing evolution of *Energy Policy*," April, <https://www.sciencedirect.com/science/article/pii/S030142152030210X?via%3Dihub>
- Brown, M.A. Anmol Soni, and Yufei Li. (2020) "Estimating Employment from Energy-Efficiency Investments" *MethodsX* Volume 7, 100955, June. <https://doi.org/10.1016/j.mex.2020.100955>
- Brown, M.A. Yufei Li, & Anmol Soni. (2020) Are All Jobs Created Equal? Regional Employment Impacts of a U.S. Carbon Tax, *Applied Energy*, Vol. 262, 15 March, 114354 <https://doi.org/10.1016/j.apenergy.2019.114354>
- Brown, M.A. & Majid Ahmadi. (2019) Would a Green New Deal Add or Kill Jobs? *Scientific American*, <https://www.scientificamerican.com/article/would-a-green-new-deal-add-or-kill-jobs1/>
- Brown, M.A. & A. Soni. (2019). Expert perceptions of enhancing grid resilience with electric vehicles in the United States, *Energy Research and Social Science*, 2019 (57) 17 pages. <https://doi.org/10.1016/j.erss.2019.101241>



- Shen, Huizhong, Yilin Chen, Yufei Li, Armistead G. Russell, Yongtao Hu, Lucas R. F. Henneman, Mehmet Talât Odman, Jih-Shyang Shih, Dallas Burtraw, Shuai Shao, Hao-fei Yu, Momei Qin, Zhihong Chen, Abiola S. Lawal, Gertrude K. Pavur, Marilyn A. Brown, Charles T. Driscoll. (2019) "Relaxing energy policies on top of climate

change will significantly undermine States' efforts to attain U.S. ozone standards," *One Earth*, 1(2): 229-239.
[https://www.cell.com/one-earth/fulltext/S2590-3322\(19\)30073-9](https://www.cell.com/one-earth/fulltext/S2590-3322(19)30073-9)

- Huibin Du, Zhenni Chen, Marilyn A. Brown, Yangyang Yna, Jian Zuo, and Lihe Chai, "How secure are national energy systems: A dynamic assessment approach." *Ecological Indicators*. Volume 18, <https://authors.elsevier.com/a/1ZmFq,XRNLcsXY>
- Brown, M.A., A. Soni, M.V. Lapsa, K.A. Southworth, M. Cox. (2019) "Low-Income Energy Affordability in an Era of Energy Abundance," *Progress in Energy*, Vol. 1, <https://dx.doi.org/10.1088/2516-1083/ab250b>
- Romero-Lankao, P., Wilson, A., Sperling, J., Miller, C., Zimny-Schmitt, D., Bettencourt, L., Wood, E., Young, S., Muratori, M., Arent, D., O'Malley, M., Sovacool, B. K., Brown, M. A., Southworth, F., Bazilian, M., Gearhart, C., Beukes, A., & Zund, D. (2019). Urban electrification: Knowledge pathway toward an integrated research and development agenda. SSRN Electronic Journal, 10. *Mansueto Institute for Urban Innovation Research Paper No. 10* <https://doi.org/10.2139/ssrn.3440283>
- Brown, M.A., A. Favero, V.M. Thomas, and A. Banboukian. (2019) "The Economic and Environmental Performance of Biomass Power as an Intermediate Resource for Power Production," *Utilities Policy*, 58: 52-62.
- Kim, Yeong Jae and Marilyn A. Brown. (2019) "Impact of Energy-Efficiency Policies on Innovation: The Case of Lighting Technologies." *Energy Policy*, 128, 539-552.
- Monyei, C., B. K. Sovacool, M. A. Brown, K. Jenkins, S. Viriri, and Y. Li. (2019) "Justice, Poverty, and Electricity Decarbonization," *The Electricity Journal*, 32(1), 47-51.
- Zhou, S., D.C. Matisoff, G.A. Kingsley, and M.A. Brown. (2019) "Understanding renewable energy policy adoption and evolution in Europe: The impact of coercion, normative emulation, competition, and learning" *Energy Research and Social Sciences*, 51: 1-11, <https://doi.org/10.1016/j.erss.2018.12.011>
- Brown, S.P.A., M. Jefferson, M.A. Brown, R. Madlener, S.D. Thomas, and P. Zhou. 2018. "Recent Developments and Future Directions at Energy Policy," *Energy Policy*, 121: A1-A2.
- Liu, X., Du, H., Brown, M. A., Zuo, J., Zhang, N., Rong, Q., & Mao, G. (2018). Low-carbon technology diffusion in the decarbonization of the power sector: Policy implications. *Energy Policy*, 116, 344-356, <https://doi.org/10.1016/j.enpol.2018.02.001>.
- Rudd, M. A., Moore, A. F., Rochberg, D., Bianchi-Fossati, L., Brown, M. A., D'Onofrio, D., ... & Risse, L. M. (2018). Climate research priorities for policy-makers, practitioners, and scientists in Georgia, USA. *Environmental Management*, 1-20, <https://doi.org/10.1007/s00267-018-1051-4>.
- Brown, M. A., & Li, Y. (2018). Carbon pricing and energy efficiency: pathways to deep decarbonization of the US electric sector. *Energy Efficiency*, 12(2), 463-481, <https://doi.org/10.1007/s12053-018-9686-9>.
- Zhang, W., Robinson, C., Guhathakurta, S., Garikapati, V. M., Dilkina, B., Brown, M. A., & Pendyala, R. M. (2018). Estimating residential energy consumption in metropolitan areas: A microsimulation approach. *Energy*, 155, 162-173, <https://doi.org/10.1016/j.energy.2018.04.161>.

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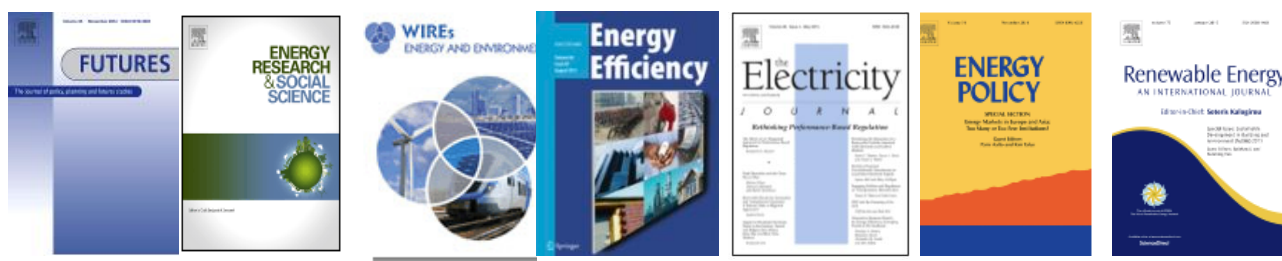
- Brown, M. A., Zhou, S., & Ahmadi, M. (2018) Smart grid governance: An international review of evolving policy issues and innovations. *Wiley Interdisciplinary Reviews: Energy and Environment*, <https://onlinelibrary.wiley.com/doi/full/10.1002/wene.290>.
- Robinson, C., Dilkina, B., Hubbs, J., Zhang, W., Guhathakurta, S., Brown, M. A., & Pendyala, R. M. (2017). Machine learning approaches for estimating commercial building energy consumption. *Applied Energy*, 208, 889-904, <https://doi.org/10.1016/j.apenergy.2017.09.060>
- Zou, H., Du, H., Brown, M. A., & Mao, G. (2017). Large-scale PV power generation in China: A grid parity and techno-economic analysis. *Energy*, 134, 256-268, [doi:10.1016/j.energy.2017.05.192](https://doi.org/10.1016/j.energy.2017.05.192).
- Pandit, A., Minné, E. A., Li, F., Brown, H., Jeong, H., James, J. A. C., ... & Yang, P. (2017). Infrastructure ecology: an evolving paradigm for sustainable urban development. *Journal of Cleaner Production*, 163, S19-S27.
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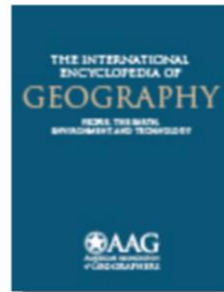
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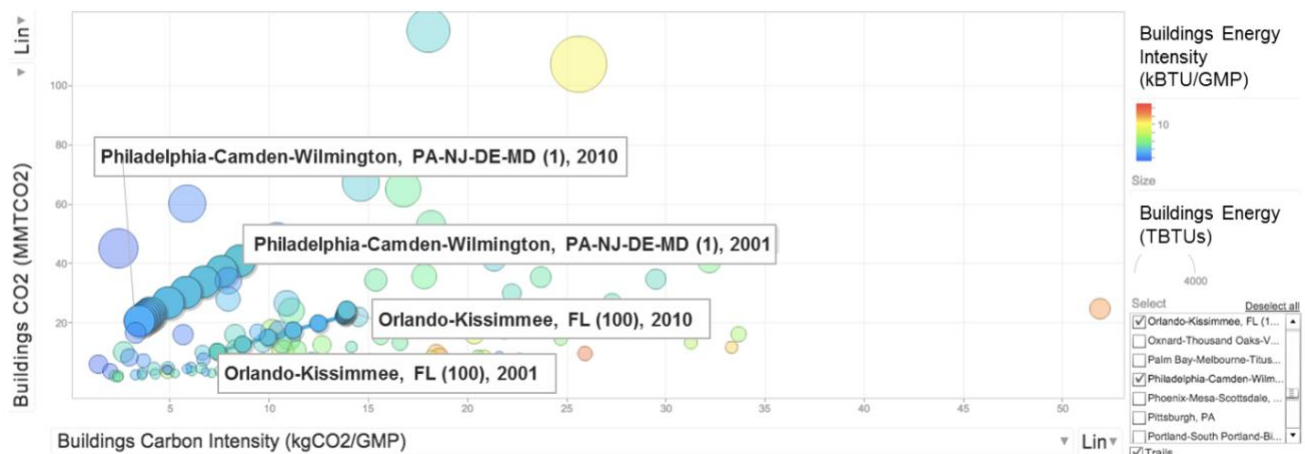
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Figure 2: Metros with the Least (Orlando) and Most (Philadelphia) Improved Buildings Carbon Footprints



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<http://blogs.knoxnews.com/humphrey/2009/12/obama-nominates-clean-energy->

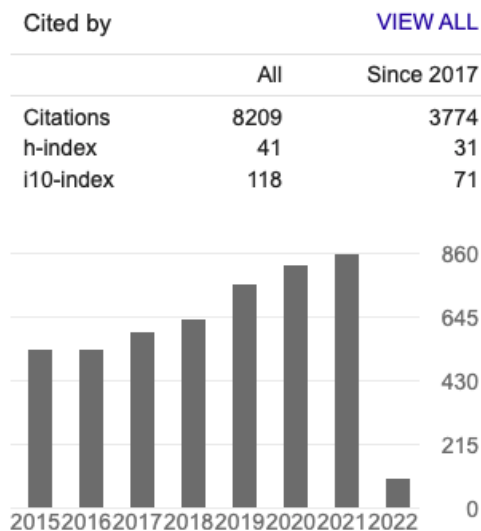


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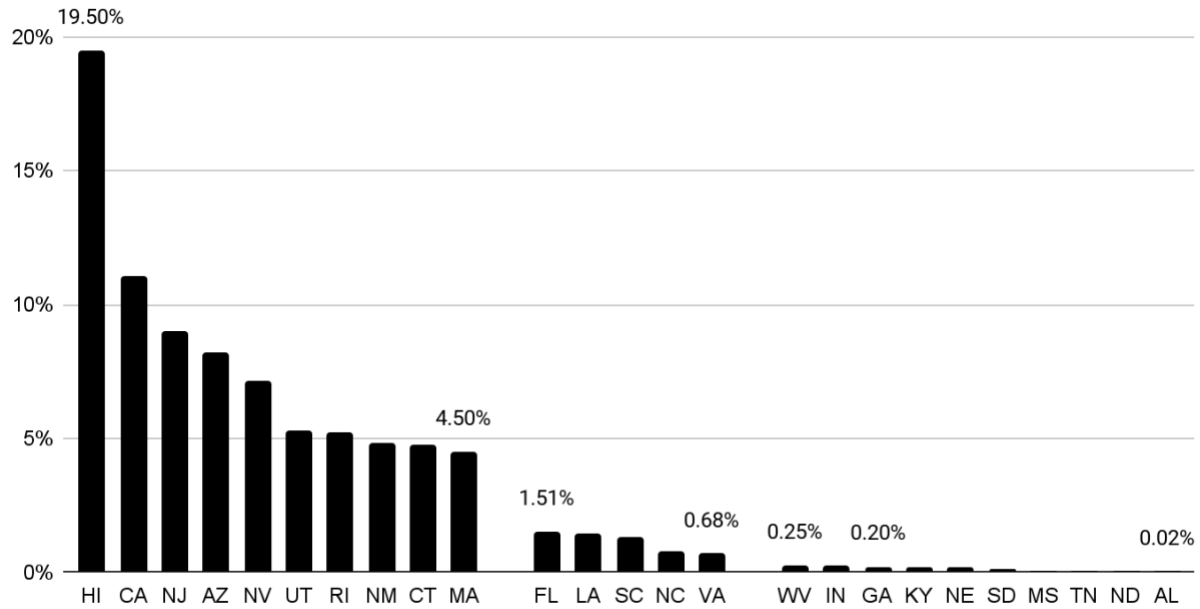
Verified email at pubpolicy.gatech.edu - [Homepage](#)

[Energy and Climate Policy](#)



MAB-Exhibit-2

Distributed Energy Generators as Percentage of Households, through June 2022

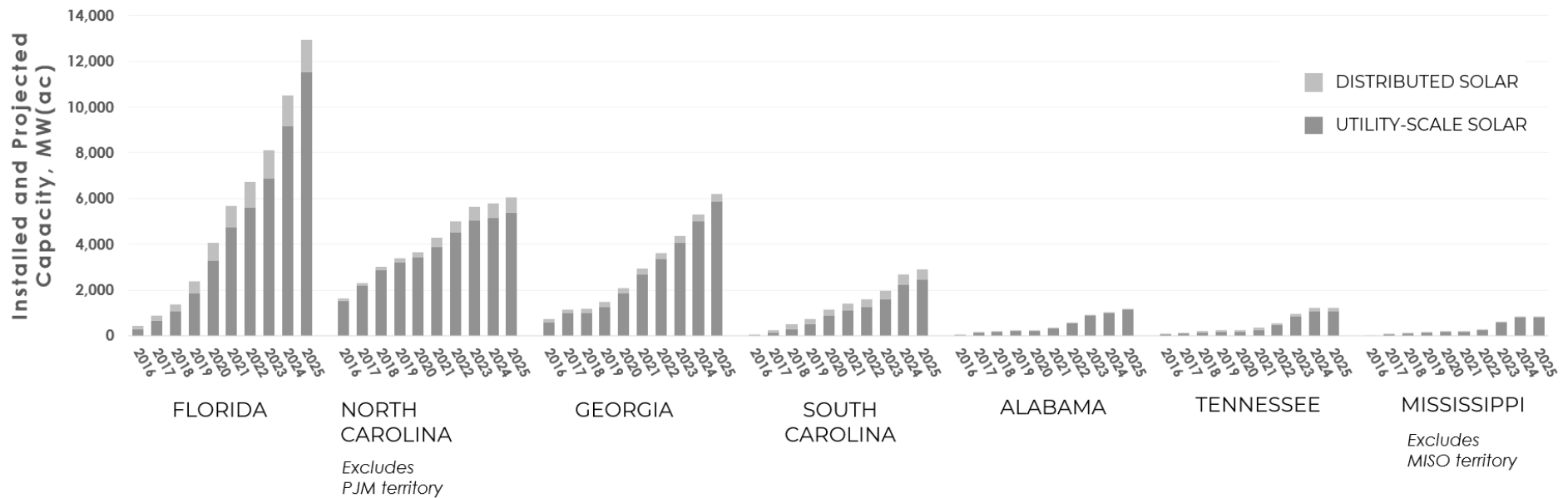


Source: EIA 2022 for Number of Net Metering and Non-Net Metering Generators and U.S. Census Data 2021 for Households.

MAB-Exhibit-3

Slow Growth Forecasted for Distributed Solar in Georgia: 2016-2025

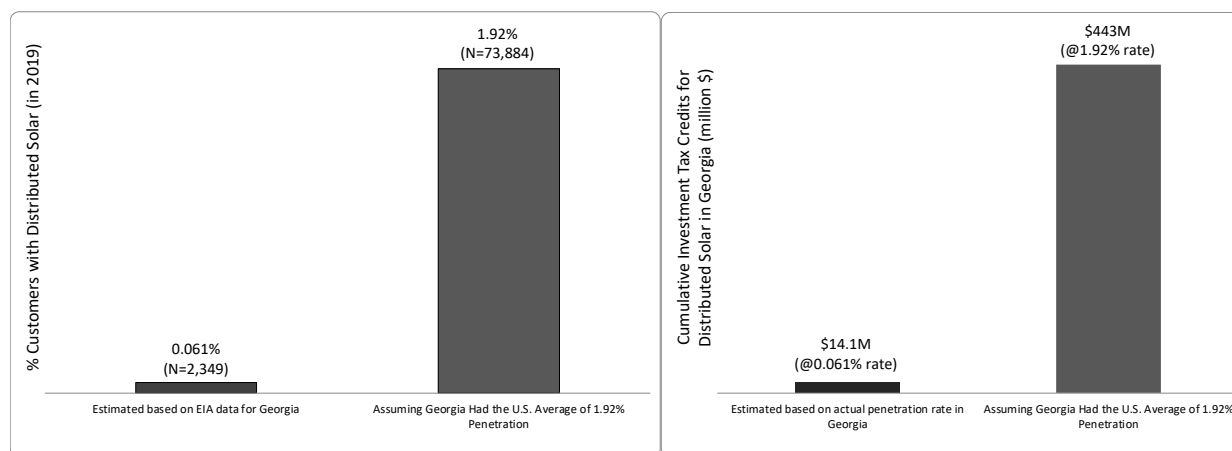
FORECAST FOR SOUTHEAST STATES



Source: Jacob, B. July 2022.

MAB-EXHIBIT-4:

Figure 5. Fewer Distributed Solar Systems in 2019 Means \$429 Million in Tax Revenues Did Not Come to Georgia from 2010-2019



Data Sources: EIA and U.S. Census.

Based on analysis of residential distributed solar systems and net energy metering policies in 49 continental U.S. states, 2010-2019. Data sources: U.S. EIA; Smith et al., 2021¹; Barbose et al., 2021²; U.S. Census Data.

¹ Smith, K.M, C. Koski, and S. Siddiki, 2021, Regulating net metering in the United States: A landscape overview of states' net metering policies and outcomes, *Electricity Journal*, Volume 34, Issue 2.

² Barbose, G. S. Forrester, E. O'Shaughnessy, and N. Darghouth, 2021, *Residential Solar-Adopter Income and Demographic Trends: 2021 Update*, Lawrence Berkeley National Lab.

MAB-Exhibit-5

		Residential Distributed Generation Interconnection Fees	
		<u>Fixed Initiation Fee</u>	
		No	Yes
<u>Variable Fees per System Size</u>	No	Pedernales Electric Cooperative (TX) Arkansas IOUs and Co-ops Sacramento Muni. Energy Utility District Florida Power and Light South Carolina Tucson Electric Orlando Utilities Commission Kentucky Jacksonville Electric Authority Austin Energy Xcel Energy New Mexico	North Carolina \$50 application fee New Mexico \$50 application fee SCE \$75 one time Connection Fee Mississippi Power \$87 one time meter fee Eversource \$100 application fee Liberty Utility \$100 application fee SDG&E \$132 one time Connection Fee PG&E \$145 one time Connection Fee Proposal: Georgia Power \$200 one time Connection Fee
	Yes	Existing: Georgia Power \$5/kW one time connection fee New York IOUs \$0.69-\$1.09/kW Monthly Capacity Charge Alabama Power \$5.41 kW Monthly Capacity Charge Arizona Public Service \$0.93/kW Monthly grid access charge El Paso Electric \$15 monthly flat fee Kansas Evergy \$3/kW (Oct-May) or \$9/kW (June-Sept) monthly demand charge	Some utility companies require larger fees for C&I customer with large distributed solar systems

1 Q Dr. Brown, did you also cause to have prefiled
2 five exhibits marked MAB-1 through MAB-5?

3 A (Witness Brown) Yes.

4 Q Do you have any revisions or corrections to the
5 exhibits?

6 A (Witness Brown) I do not.

7 MR. DOWDY: Madam Chairman, I would ask that
8 the exhibits MAB-1 through 5 be marked as hearing
9 Exhibits SS-7 through 11.

10 MADAM CHAIR PRIDEMORE: So marked.

11 (The documents referred to were marked for
12 identification as SACE and Southface Exhibits 7
13 through 11.)

14 BY MR. DOWDY:

15 Q Mr. Hathaway, let me ask you, if you would, to
16 state your name and occupation for the record.

17 A (Witness Hathaway) Thank you. My name is
18 Alden M. Hathaway. I am a senior energy engineer and
19 project manager at 2RS Consulting, LLC.

20 Our business address is P.O. Box 541, Palmyra,
21 Virginia. And although locally we are operating out of my
22 home, 4025 Pinebrook Circle, Cumming, Georgia. And I'm
23 testifying on behalf of the Southern Alliance for Clean
24 Energy and Southface Energy Institute.

25 I'm a state of Georgia professionally licensed

1 professional engineer in power, energy, and general
2 electrical knowledge, and a professional engineer with
3 nearly 41 years of consulting engineering management
4 experience. And I'll be testifying on -- about my -- about
5 the electrical knowledge.

6 I actually started my career here in Georgia
7 with Georgia Power. They recruited me out of the electrical
8 engineering department at the University of Virginia. And
9 in my last year with the company, '82 to '83, I was the
10 district engineer for the district office in Manchester,
11 Georgia, where we designed electric services for our
12 customers and/or proposals.

13 That Manchester district encompasses an area
14 including Newnan, LaGrange, West Point, Manchester, and
15 Talbot. It's one of the largest districts in the Georgia
16 Power service territory just geographically.

17 My comments represent my opinions and not the
18 company I work for. Thank you.

19 Q Thank you, Mr. Hathaway.

20 Did you also cause to have prefiled in this
21 proceeding 23 pages of question-and-answer testimony?

22 A (Witness Hathaway) I did.

23 Q Do you have any corrections or revisions to
24 that testimony?

25 A (Witness Hathaway) I do not.

1 Q So if the questions were asked of you today
2 from the stand, your answers would be those as prefiled?

3 A (Witness Hathaway) Yes.

4 MR. DOWDY: Madam Chairman, at this time I
5 would ask that the testimony of Mr. Hathaway be
6 copied into the record as if given orally from the
7 stand.

8 MADAM CHAIR PRIDEMORE: So moved.

9 (Whereupon, the prefiled direct testimony and
10 errata of Alden M. Hathaway, P.E., C.E.M. follows:)

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**STATE OF GEORGIA
BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION**

In Re: Georgia Power Company's 2022 Rate Case	)	DOCKET NO. 44280
	)	
	)	

**DIRECT TESTIMONY OF ALDEN M. HATHAWAY, P.E. C.E.M.
ON BEHALF OF SOUTHERN ALLIANCE FOR CLEAN ENERGY
AND SOUTHFACE ENERGY INSTITUTE, INC.**

November 18, 2022

1 **Q1: PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.**

2 A1: My name is Alden M. Hathaway. I am the Senior Energy Engineer and Project Manager
3 for 2RS Consulting, LLC. Our business address is PO Box 541, Palmyra, Virginia 22963,
4 although we operate locally out of 4025 Pinebrook Circle, Cumming, GA 30028.

5 **Q2: ON WHOSE BEHALF ARE YOU TESTIFYING?**

6 A2: I am testifying on behalf of the Southern Alliance for Clean Energy (“SACE”) and
7 Southface Energy Institute (“Southface”) before the Georgia Public Service Commission
8 (“Commission”).

9 **Q3: MR. HATHAWAY, PLEASE SUMMARIZE YOUR EDUCATIONAL AND**
10 **PROFESSIONAL EXPERIENCE.**

11 A3: I am licensed by the State of Georgia as a registered Professional Engineer in the
12 Engineering Power, Energy and General Electrical Knowledge disciplines, with nearly 41
13 years of consulting, engineering management, sales, and project development experience
14 in the fields of solar, wind and energy efficiency systems. My Georgia State License
15 Number is #035053.

16 I am also a registered Professional Engineer in the State of South Carolina for the
17 same Power and Energy Disciplines. My South Carolina License Number is No. 34482.
18 Our consulting practice is focused on energy and sustainability support with engagement
19 in the federal, state, and private sectors.

1 My areas of expertise include: energy efficiency, including lighting, HVAC and
2 industrial process energy efficiency; renewable energy, including solar and wind,
3 bioenergy and renewable natural gas; energy storage technology, including controls,
4 thermal and electric battery; micro-grids, controls and energy dashboards; plug-in electric
5 vehicles; electrical infrastructure; electric demand and energy bill analysis; Renewable
6 Energy Certificates (“RECs”), Energy Efficiency Credits (“White Tags”) and Carbon
7 Offsets, development, tracking mechanisms, sales and consulting.

8 In my 40+ years of experience, I have worked for three years for two electric
9 utilities, including Georgia Power and Eastern Edison in their energy services and power
10 marketing departments. For over a decade, I worked for two manufacturers, GTE Sylvania
11 Lighting and Solarex (a solar manufacturer, originally based in Frederick, MD). For
12 another decade, I worked as an energy consultant in Washington, D.C. for the U.S. EPA’s
13 Energy Star and Green Power Partnership programs, marketing for and implementing the
14 program on behalf of over 1,000 member partners as a manager of a team of up to 16 field
15 engineers. The remaining decade and a half I served Sterling Planet, one of the nation’s
16 largest retailers of renewable electricity as its SVP for Business Development, supporting
17 utilities and commercial companies alike in renewable energy procurement, green power
18 programs, REC and Carbon Offset sales, and solar and energy-efficient lighting project
19 development and application.

20 I have developed, hold, or been named on three U.S. Patents regarding an Energy
21 Efficient Lighting System, a Direct-Current Based Solar and Lighting Interconnection
22 System, and an Energy Monitoring Algorithm using Artificial Intelligence to Predict

1 Baselines for White Tag Measurements. I have been recognized with awards by both the
2 U.S. EPA Market Development of the Energy Star Buildings Program (1995) and the U.S.
3 Department of Energy Wind Advocacy Award (2005). I was named as Loudoun County,
4 Virginia's Environmental Volunteer of the Year in 2001 for the development of a solar and
5 energy system at the Barns of Franklin Park. I was also recognized as an Association of
6 Energy Engineers ("AEE") "Legend in Energy" in 2011. I have been a Certified Energy
7 Manager since 1993.

8 I co-founded and have maintained my role as Board Member for the 25-year-old
9 non-profit organization, Solar Light for Africa, which has presided over the installation of
10 over 2,800 solar lighting, power, and water systems in nine sub-Saharan African Countries,
11 including Uganda, Tanzania, Rwanda, Kenya, Ethiopia, Sudan, Ghana, Liberia, and Sierra
12 Leone. Most systems were off-grid Direct Current based systems, but at least 50 of those
13 systems were grid-tied and 20 of them microgrid systems. I have also been involved with
14 and/or directly developed solar-microgrid type (solar plus battery plus load) systems in
15 Massachusetts, Pennsylvania, Virginia, and Georgia.

16 I have authored two books on Solar Energy and Net Zero Energy Homes about my
17 family's solar home in Virginia and our second solar home in Georgia, including my latest
18 publication, **Energy Independence – The Individual Pursuit of Energy Freedom**,
19 published by River Publishing in 2022. Our first solar home has been featured in at least
20 two other books and major publications: including **The Greened House Effect**, Jeff
21 Wilson, Chelsea Green Publishing, 2013; **The Hathaway "Solar Patriot" House: A Case**
22 **Study in Efficiency and Renewable Energy**, Paul Norton, National Renewable Energy

1 Laboratory, 2005; *Piedmont Magazine*, 2008, the front cover of (and inside story) *Mother*
2 *Earth News*, 2003; the *Washington Post*, 2002; *Solar Today*, 2002; and President Bush's
3 *National Energy Policy Plan*, May, 2001. Our first solar home was featured on the National
4 Capital Mall for Earth Day 2001 and was visited by over 26,000 people including EPA
5 Administrator Whitman, 14 members of Congress, three U.S. Senators, a number of White
6 House staffers, and DOE officials.

7 I have written extensively on energy policy, energy design and marketing programs,
8 including in: *Public Utilities Fortnightly*, *Consulting/Specifying Engineer*, *AEE Energy*
9 *Engineering Journal*, *Energy User News*, *World Aid Directory*, *Solar Today* and *North*
10 *American Clean Energy*. The topics ranged from integrated building designs including
11 lighting, HVAC, and solar to increasing load factor on utility systems to reduce overall
12 system cost.

13 I hold a Bachelor of Science Degree in Electrical Engineering from the University
14 of Virginia. AMH-Exhibit-1 includes my full curriculum vitae.

15 **Q4: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC**
16 **SERVICE COMMISSION?**

17 A4: No, I have not previously testified before the Georgia Public Service Commission.

18 **Q5: WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

19 A5: The purpose of my testimony is to comment on the current electrical efficiency of the
20 electric grid in Georgia, and the propensity to which that efficiency could be improved
21 through distributed generation technologies deployed at the load, including solar. In my

1 analysis, I project a cost savings across the electrical transmission and distribution system
2 when deploying the same distributed energy technology that rebuts Georgia Power witness
3 testimony suggesting a cost shift from solar customers to non-solar customers. It is my
4 opinion, based on this analysis, that an efficiency across the system benefitting the entire
5 system of ratepayers, therefore, cannot be a cost shift to non-solar customers adversely
6 affecting their costs, but a natural savings shared by all.

7 My testimony will address the structure of generating, transmission, and
8 distribution assets in Georgia and electricity sales through all assets to all Georgia Power
9 customers in the state. I provide a calculation to show the average system load factor, or
10 degree to which those assets are utilized, and then a comparison to other systems where
11 system load factor has been improved, and by what degree. I then summarize a system cost
12 reduction on a percentage basis for each basis point improvement in load factor based on
13 other systems, and project the potential system cost reduction in Georgia by pursuing a
14 distributed solar generation rooftop program.

15 Finally, I will rebut earlier testimony by, Ahmad Faruqui, Ph.D. to this Commission
16 in 2019 on there being a cost shift from solar generator to non-solar electrical users, with
17 his own recently published statements, now claiming that solar, especially with battery
18 storage, reduces transmission and distribution costs across the system. This is further
19 supported by Southern Company's own experience in two residential solar microgrid
20 projects in Alabama and Georgia that will also be pointed to in this testimony. With this
21 rebuttal, and new-found information pointing with confidence in the ability of distributed
22 generation to lower costs across the system, I will stress that the position by the

Commission on solar net metering should now be reversed to give full energy credit for all kWh generated by individual solar generators.

Q6: ARE YOU SUBMITTING EXHIBITS ALONG WITH YOUR TESTIMONY?

A6: Yes, I am submitting two (2) exhibits along with my testimony, as follows:

1. AMH-EXHIBIT-1: Curriculum Vitae of Alden Hathaway; and
2. AMH-EXHIBIT-2: Tax Shift of Funds to Other States from Georgia Citizens Each Year Solar NEM is Unavailable.

Q7: MR. HATHAWAY, DO YOU HAVE ANY REASONS TO SUPPORT YOUR CLAIM THAT NET METERING IS IMPORTANT FOR COMMERCIAL AS WELL AS RESIDENTIAL CONSUMERS?

A7: Yes. I serve on the building committee and Green Guild of St. David's Episcopal Church in Roswell, Georgia. I also lead a missions program to Africa, called Solar Light for Africa, that is supported by the church. St. David's has embarked on an ambitious campaign to reduce its energy consumption through energy efficiency and is considering solar as well, under the provision, that the more energy costs it can save, the more can be set aside for supporting missions programs. Solar would have been considered by St. David's, except that the current position on reimbursing only at the wholesale solar rate does not generate enough savings to service the cost of solar.

As a church on a demand rate, like St. David's, there is a demand penalty that sets in during Sunday services that causes the church to pay a much higher rate for electricity, even though this demand is set during a time (Sunday morning) when system demand is

1 not peaking. The use of solar would help reduce this peak demand. However, if the sale of
2 energy is only valued at the current solar buyback rate, it will not even pay for itself let
3 alone help the church limit demand on the Georgia Power Company system and free up
4 funds for our mission to Africa.

5 This church-electric demand problem was recently highlighted in an article in
6 Utility Dive,¹ “Avoiding the ‘tax on God’ dilemma when transitioning to dynamic rates.”
7 The article points out that more and more churches are falling victim to dynamic demand
8 rate costs when demand is set for Sunday services.

9 Along with energy efficiency, net metering one-for-one for solar is an elegant way
10 to solve this problem.

11 **Q8: MR. HATHAWAY, CAN YOU EXPLAIN WHAT HAPPENS TO ELECTRICAL**
12 **CURRENT WHEN IT IS GENERATED AT OR NEAR THE LOAD?**

13 A8: Electric current will, as defined by Ohm’s law,² flow in the greater amount through the
14 path of least resistance. Although current will flow in other paths of higher resistance to
15 ground, *the majority of current* will be found in the lowest resistant circuit(s) to
16 ground. Long distance distribution wires have resistance to electric current associated with
17 them. This resistance is directly proportional to the length of the wire and acts as additional
18 resistance to electricity flowing back to the source. The longer the wires the more
19 resistance. When electric current is generated near the load it will flow in the greatest

¹ Langley, Brad (2022) Avoiding the ‘tax on God’ dilemma when transitioning to dynamic rates, **Utility Dive**,
<https://www.utilitydive.com/spons/avoiding-the-tax-on-god-dilemma-when-transitioning-to-dynamic-rates/632110/>.

² Ohm, Georg (1827) “The galvanic circuit investigated mathematically” (Ohm’s Law)
 $I = E / (r + Rl) \rightarrow I = V / R$, https://en.wikipedia.org/wiki/Ohm's_law.

1 amount through the nearest closed switches and breakers onto electric ground. If all
2 switches are suddenly opened at the main load of the generator source, then the current will
3 now flow in greatest amount onto the connecting wires to the next nearest load and through
4 its switches and breakers to ground. If those switches are opened the current will flow to
5 the next nearest load and so on.

6 You can picture it like a water system with a pipe delivering water from a source
7 to a use (or several uses) downhill. The water, once in the pipe, has nowhere to flow but
8 down to the water uses. If additional sources are located near the uses, they will not flow
9 back uphill but rather to the uses further downhill. If the spigot is closed at the first use the
10 water will spill through the pipe to the next nearest use. If that spigot is closed it will flow
11 to the next nearest use and so on. It will, for all intents and purposes, not flow back up the
12 water pipe to the main source because in a multiple use system, there will always be a use
13 open for the water in the neighborhood of uses.

14 Electric current operates in the same way. There are so many nearby loads that the
15 electric current from a local generating source will always find a nearby load to flow
16 through. The local electric current will always directly support the local electric loads,
17 benefitting the local electric circuit.

18 **Q9: HOW DO THE ELECTRIC METERS OF NEXT DOOR HOMES THAT RECEIVE**
19 **THIS NEARBY DISTRIBUTED GENERATED ELECTRICITY RECORD THAT**
20 **ENERGY?**

21 A9: Electric meters do not typically distinguish between electricity from one source or another.
22 The current that flows off of a solar generator system, when not being used by the owner,

1 will flow onto the wires and through the neighbor's meter to their loads. To the neighbor,
2 the meter simply records electricity used through the wires the house is connected to and
3 would be billed for electricity as if it came from the power plant supplying the electric grid.
4 However, the impact of this to the circuit feeding this neighborhood is a reduction in the
5 apparent load on the circuit in direct amount equivalent to the capacity of the solar system
6 on the home.

7 **Q10: WHY SHOULD THIS PRACTICE BE ENCOURAGED FROM AN ELECTRICAL**
8 **SYSTEMS POINT OF VIEW?**

9 A10: Reducing load at the end point of a distribution system reduces the loading on the entire
10 circuit feeding the neighborhood. For utilities with a summertime peak typically occurring
11 in the afternoon, the aggregate summation of solar systems on multiple circuits means that
12 summer peak load reductions are passed back to the substation reducing loading on the
13 transmission lines feeding those substations. For reference of summertime peaking utilities
14 see SACE's analysis.³

15 Georgia utilities are considered to be summer peaking in general. This means the
16 electric utility can continue to serve a growing commercial and industrial peaking
17 afternoon load with confidence that solar generation is offsetting that growing peak load.
18 Ultimately, this means the utility can forestall otherwise necessary infrastructure
19 investment (additional transmission, new substation transformers, reconductored

³ Wilson, John; Shober, Maggie (2020) Seasonal Electric Demand in the Southeastern United States, **Southern Alliance for Clean Energy**, <https://cleanenergy.org/wp-content/uploads/Seasonal-Electric-Demand-in-SE-SACE-Final.pdf>.

1 distribution circuits) saving the entire rate base, otherwise adversely impacted, by those
2 additional costs.

3 **Q11: DO OTHER STATES CONSIDER THE BENEFITS OF DISTRIBUTED**
4 **GENERATION IN THIS WAY?**

5 A11: Yes, many utilities offer solar net metering with the general understanding that it positively
6 impacts their system by offsetting any loss of revenue from the solar generator. Right now,
7 solar net metering (one-for-one credit for solar generation) is offered in a majority of the
8 states⁴ (at least 33 by recent count) across the country. Some states have taken it a step
9 further. In South Carolina, the Commission has introduced the first real-time priced solar
10 net metering, varying the credit with the varying cost to serve electricity within time of use
11 periods.⁵

12 **Q12: ARE THERE ANY STUDIES OF UTILITY SYSTEMS AS A WHOLE ACHIEVING**
13 **SIGNIFICANT COST REDUCTIONS BY FOCUSING ON DISTRIBUTED**
14 **GENERATION?**

15 A12: The most famous case of a long-term policy of distributed and demand-side focus by a
16 utility was documented over a 20-year period by the Central Vermont Public System
17 (“CVPS”) and published in the *Electricity Journal*.⁶ The report documented a focused
18 utility approach towards investment in energy efficiency, demand response, and distributed

⁴ Pickrel, Kelly (2022) Update – Which States Offer Net Metering?, **Solar Power World**,
<https://www.solarpowerworldonline.com/2020/03/which-states-offer-net-metering/>.

⁵ Penrod, Emma (2021) South Carolina to Implement net metering settlement with time-of-use pricing; **Utility Dive**,
<https://www.utilitydive.com/news/south-carolina-to-implement-net-metering-settlement-with-time-of-use-pricing/600581/>.

⁶ See Spinner, Howard (1992) The Peak Shifts – 18 Years of Load Management, **The Electricity Journal**, and
Spine, Havel Nos (2002) Demand Response: The Future Ain’t what it used to be or is it?, **The Electricity Journal**.

1 generation technology in lieu of traditional capacity investment to increase overall system
2 load factor from 55% to 70%.

3 **Q13: WHAT WAS THE REDUCTION IN SYSTEM COSTS FROM THE CVPS**
4 **PROGRAM?**

5 A13: The project's proponent reported the system achieved an overall reduction of \$10 million
6 in system costs. If one were to extrapolate across the average ratepayer's bill, assuming
7 100% went back to the ratepayer, it would represent approximately \$38 annually in savings
8 (about 4%).

9 **Q14: WHAT IS SYSTEM LOAD FACTOR?**

10 A14: Load factor is the ratio of total energy used to serve the load of a given system divided by
11 the total amount of energy that could be generated and pushed through the transmission
12 and distribution system if the load was operated around the clock (24 hours per day, 365
13 days per year). The average load factor in the U.S. electrical system is about 50%. A 50%
14 system load factor means that a system designed to supply 1 MW of electric capacity to
15 serve a load and could deliver 8,760 MWh of energy to that load over the course of a year
16 actually only supplies 4,380 MWh of electricity. Because most of the cost of electric supply
17 is tied up in the capacity of the 1 MW system, including power generation, transmission
18 and distribution, there is little additional cost in operating at a higher load factor other than
19 the additional fuel to keep the plant operating. Therefore, a higher load factor results in a
20 significant reduction in the cost per kWh for energy than a lower load factor does.

1 Consider load factor like you would consider operating a manufacturing plant on
2 one, two, or three eight-hour shifts per day operations. The plant that operates on one shift
3 per day shows $8 / 24 = 33\%$ load factor. The plant that operates on two shifts per day shows
4 $16 / 24 = 67\%$ load factor. The plant that operates on three shifts per day shows $24 / 24 =$
5 100% load factor. Obviously, all other things being equal, the high load factor
6 manufacturing plant produces units at lower overall costs than the low load factor plant.

7 **Q15: HOW DOES A UTILITY INFLUENCE THE LOAD TO GET HIGHER SYSTEM**
8 **LOAD FACTOR?**

9 A15: Central Vermont Public Service proved that long-term investment on the demand-side of
10 the meter in multiple distributed, demand-response and energy efficiency technologies
11 across the entire rate base, often referred to as Demand Side Management (“DSM”), will
12 achieve the desired increase in load factor. They started in 1974 at 55% and it took them
13 more than 20 years to raise it to 70%. Therefore, it should be the policy of the Commission
14 to seek load factor improvement whenever it is low to produce an offsetting reduction in
15 costs, especially when rates are under increased upward pressure.

16 **Q16: WHAT IS THE SYSTEM LOAD FACTOR IN GEORGIA?**

17 A16: According to the U.S. Energy Information Administration (“EIA”) data for the state of
18 Georgia,⁷ peak capacity – including utilities, independent power production (“IPP”) and
19 combined heat and power (“CHP”) – is 37,279 MW (37.279 GW). At 100% load factor,
20 this would yield energy production of $37.279 \text{ GW} \times 8,760 \text{ hours per year} = 325,564 \text{ GWHs}$

⁷ Energy Information Administration, Georgia Electricity Profile (2020)
<https://www.eia.gov/electricity/state/archive/2020/georgia/>.

per year. According to the same report net generating data is actually 120,126 GWHs per year. Load factor then is $120,126 / 325,564 = 36.8\%$. If we separate out data for what is owned and operated by Georgia utilities with peak capacity of 27,253 MW (27.253 GW) and net generation of 96,522 GWHs per year, the load factor calculation is only slightly better at 40.4%. In other words, even though ratepayers have essentially paid for a system capable of delivering up to 325,564 GWHs per year, the entire Georgia electric system barely achieves an average load factor slightly above a one shift operation.

Q17: HAVE YOU EVER STUDIED LOAD FACTORS IN GEORGIA COMPARED TO OTHER NEIGHBORING STATES?

A17: Yes, I wrote about it in *North American Clean Energy Magazine*, 2013.⁸ I looked into the load factors of Tennessee, Alabama, Florida, South Carolina, North Carolina as well as Georgia from a period of 2008-2011. I found that during that time all states including Georgia saw a reduction in their system load factor and an increase in electric rates. Of all the six states Georgia's load factor was only better than Alabama's.

Q18: WHICH STATES HAD THE BEST LOAD FACTORS?

A18: Both North and South Carolina operate with a system load factor in the 50% range and their electric rates across all sectors (residential, commercial, industrial, and transportation) average at least 4.5% lower than Georgia.⁹

⁸ Hathaway, Alden (2013) Improving System Load Factor – A recipe for containing rates & growing renewable energy, *North American Clean Energy*, <https://www.nacleanenergy.com/>.

⁹ U.S. EIA (2021) Total Electric Industry- Average Retail Price (cents/kWh), [eia.gov/electricity/sales_revenue_price/pdf/table4.pdf](https://www.eia.gov/electricity/sales_revenue_price/pdf/table4.pdf).

**Q19: HOW MUCH COULD BE SAVED IF GEORGIA IMPROVED ITS LOAD
FACTOR TO 70%?**

A19: If the Central Vermont Public System could achieve a 4% cost reduction for a 27.3% increase in load factor, then it seems quite possible that Georgia utilities with a 73.3% increase (40.4 -70 – approximately 2.7 times) could see a 2½ fold increase in cost reduction or approximately 10% downward pressure on electric costs. It would take an aggressive program of distributed generation focus to get there, but allowing solar to be part of the solution under net metering is certainly a step in the right direction.

**Q20: HOW DOES SOLAR WITH A LOW CAPACITY FACTOR CONTRIBUTE TO A
HIGHER OVER ALL LOAD FACTOR?**

A20: For summer peaking utilities, as we have already established with the SACE material above, the peak output of the solar, occurring as it does in the mid-afternoon for areas on the western-end of the time zone (Daylight Savings) shortly after 2 PM, lines up well with the natural HVAC driven peak of the Georgia electric utility system. As such, distributed solar, especially when placed at the load end of a circuit, reduces that peak demand throughout the system with affects felt back to the supply. Yet, energy use at the load is not reduced as much, thus flattening the load curve and freeing up capacity in the circuit for other loads.

**Q21: HOW DOES SOLAR BEHIND-THE-METER BENEFIT THE SYSTEM WHEN
APPLIED AT THE LOAD?**

1 A21: When solar is placed at the load it reduces peak demand across the board from the end
2 circuit all the way back to the plants energizing the electric grid. The savings are seen in
3 reduced distribution and transmission impacts, and improved operating efficiencies at the
4 central generating stations. The projection of peak solar demand reduced through
5 Drawdown Georgia's ambitious solar goal of 295,000 solar roofs by 2028 would yield as
6 much as 1.475 GW of offsetting peak load reduction at the circuit end of the electric system
7 about 5% of the system peak demand.

8 According to a well-publicized article in *Electricity Journal*, ***The Power of 5***
9 ***Percent***, "Even a 5 percent drop in peak demand can yield substantial savings in
10 generation, transmission, and distribution costs – enough to eliminate the need for
11 installing and running 625 infrequently used peaking power plants and associated power
12 delivery infrastructure. At the national level, this translates into savings of \$3 billion a year,
13 or \$35 billion over the next two decades."¹⁰

14 **Q22: WHAT DO YOU ESTIMATE ARE THE SAVINGS OF A DISTRIBUTED**
15 **ROOFTOP SOLAR PROGRAM TO GEORGIA RATEPAYERS?**

16 A22: Drawdown Georgia has placed a goal of 295,000 solar roofs each sized at 5 kW for
17 increasing the amount of solar use by residential and small business consumers. This
18 corresponds to a 5% reduction in peak demand and improvement in system load factor by
19 the same amount.

¹⁰ Faruqui, Ahmad, Ryan Hledik, Sam Newell, and Hannes Pfeifenberger (2007) The Power of 5 Percent, **The Electricity Journal**, <https://doi.org/10.1016/j.tej.2007.08.003>.

1 Using the Central Vermont Public Service (now Green Mountain Power) as a
2 reference point; they raised their load factor by 27.3% from 55% to 70% and saw a
3 corresponding 4% savings in utility costs. Thus, raising load factor by 5% should see a
4 corresponding $((5/27.3) \times 4\%) = 0.7\%$ decline in utility operating costs per year, seen
5 primarily in distribution, transmission, and improved central plant operating cost savings.

6 If we use the metrics suggested by the article *The Power of 5 Percent* as a reference point
7 and extrapolate across the national population (333.29 million) to Georgia's population
8 (10.8 million), then the cost reduction projected can be calculated as: $(10.8 / 333.29) \times \$3.0$
9 Billion = \$97.21 million per year. \$97.21 million per year for 295,000 solar rooftop
10 customers points to a net benefit of \$329 per solar customer per year for all Georgia
11 ratepayers.

12 **Q23: ARE YOU FAMILIAR WITH JAMES C. BONBRIGHT'S PRINCIPLES OF**
13 **PUBLIC UTILITY RATES?**

14 A23: I am. In summation, Bonbright argues there are ten principles to modern rate design. The
15 Bonbright principles are almost universally cited in rate proceedings throughout the U.S. In
16 his testimony to the Commission in 2019, Dr. Ahmad Faruqui, Ph.D. claimed these ten
17 principles can be essentially condensed to five core principles:

18 1. *Energy Efficiency* – The price of electricity should convey to the customer the
19 cost of producing it, ensuring that resources consumed in the production and delivery of
20 electricity are not wasted. If the price is set equal to the cost of providing a kWh, customers
21 who value the kWh more than the cost of producing it will use the kWh, and customers
22 who value the kWh less will not use it. This will encourage the development and adoption

1 of energy technologies that are capable of providing the most valuable services to the
2 power grid, and the greatest benefits to electric customers as a whole.

3 2. *Equity* – There should be no unintentional subsidies among customer types. A
4 classic example of the violation of this principle occurs under volumetric rate pricing
5 structures (ie, cents per kWh). Since customers have different load profiles, “peaky”
6 customers who use more electricity when it is most expensive, are subsidized by less
7 “peaky” customers who overpay for cheaper off-peak electricity. Note that equity, in the
8 electric sense, is not the same as social justice, which is related to differences in
9 socioeconomic status rather than cost. The pursuit of one is not necessarily the pursuit of
10 the other, and vice versa.

11 3. *Revenue Adequacy and Stability* – Rates should recover the authorized revenues
12 of the utility and should promote revenue stability. Theoretically, all rate designs can be
13 implemented to be revenue neutral within a class, but this would require perfect foresight
14 of the future. Changing technologies and customer behaviors make load forecasting more
15 difficult and increase the risk of the utility either under-recovering or over-recovering costs
16 when rates are not cost reflective.

17 4. *Bill Stability* – Customer bills should be stable and predictable while striking a
18 balance with other ratemaking principles. Rates that are not cost reflective will tend to be
19 less stable over time, since both costs and loads are changing over time.

20 5. *Customer Satisfaction* – Rates should enhance customer satisfaction. Because
21 most residential customers devote relatively little time to reading their electric bills, rates
22 need to be relatively simple so that customers can understand them and perhaps respond to

1 the rates by modifying their energy usage patterns. Giving customers meaningful cost
2 reflective rate choices will help enhance customer satisfaction.

3 **Q24: DO YOU AGREE THAT GEORGIA POWER HAS ENERGY EFFICIENCY**
4 **BUILT INTO THE SUPPLY OF ELECTRICITY?**

5 A24: If by “Energy Efficiency” you are referring to the phrase above “*ensuring that resources*
6 *consumed in the production and delivery of electricity are not wasted,*” then my response
7 to this question is “no.” I would note that operating the system at a low 40% load factor is
8 wasting a significant amount of potential electricity resource, and therefore not energy
9 efficient.

10 **Q25: DO YOU AGREE THAT THERE SHOULD NOT BE CROSS SUBSIDIZATION**
11 **FROM ONE CUSTOMER TO ANOTHER?**

12 A25: Yes, I agree that we should seek fair and equitable rate structures that do not place a heavy
13 cost shift burden on different sets of customers. Under standard retail residential rates there
14 is a cost shift that occurs when a customer uses energy during the Georgia electrical system
15 demand peak but pays no differently for the energy used than a non-peaky customer. The
16 recent Georgia Power innovation with the smart rate is step toward addressing this
17 problem, but misses the mark by not aligning the peak demand of the customer with the
18 actual peak demand of the Georgia Power electric system. If that were done it would tend
19 to keep system costs aligned with customer costs of using energy. However, like the
20 churches I described earlier, because customers on a demand-based rate pay for demand
21 set during off-peak times the mismatch remains.

**Q26: CAN SPENDING ON THE DEMAND SIDE OF THE METER TO INCREASE
LOAD FACTOR SUPPORT REVENUE ADEQUACY AND STABILITY?**

A26: Yes. This is where the Commission can provide significant help to the utility to assure the recovery of authorized revenues and still encourage load factor improvement. The Commission has done a great job in rewarding Georgia Power in building a clean electric grid on the supply side. Now it can continue to build in clean electric capacity on the load side. The Commission should provide an additional sum (or return on equity) for all spending documented on the load side (demand-side) of the electric meter plus a bonus for increasing load factor since that would ultimately lead to lower system costs. Furthermore, spending on the demand-side of the meter will be cost-shared with the customer making the demand-side investment much less costly than on the supply-side. Solar at the load is the most effective technology to hit the peak demand of the Georgia electric system.

Q27: DO YOU BELIEVE WE HAVE BILL STABILITY IN GEORGIA?

A27: Historically, yes, but more recently, no. Georgia used to lead the nation with historically low electric rates. The average electric rates in Georgia are just under the national average. In the Southeast, only Florida has higher electric rates, and there is a good chance Georgia will soon overtake Florida, making it harder to recruit corporations when all its surrounding competitor states could boast lower electric costs.

And growth in Georgia will continue to put upward pressure on those rates if we continue to only focus on the supply-side for investment. According to an article in the

1 Center Square¹¹ citing a study by the Weldon Cooper Center for Public Service at the
2 University of Virginia, Georgia's population is projected to expand by 19.5% between
3 2020 and 2040, moving it to the 5th most populous state in the country from 8th today. This
4 growth requires a corresponding growth in the ability to meet electric load over the next
5 20 years. We have seen what a focus on "only the supply side of the equation" has wrought
6 in terms of electric rate costs (with rate increases of more than 40%). As I have shown with
7 only a 40% load factor there is plenty of capacity room on the load side of the meter.

8 It is now a great opportunity to put the more cost competitive "demand-side of the
9 equation" investment to work to meet future load growth. Under the latter scenario, we
10 would hope to see average kWh per customer reduced to make way for new customers
11 coming online, all with zero carbon technology on the demand-side, continuing Georgia's
12 leadership in a clean energy electric system at moderate electric prices.

13 **Q28: DO YOU AGREE THAT SIMPLE RATES ARE IMPORTANT FOR CUSTOMER**
14 **SATISFACTION?**

15 A28: Yes, one of the reasons I advocate for solar net metering is that I agree with that principle
16 above as electric customers understand the one-for-one credit when they generate their own
17 solar energy, especially as they believe they are doing what is right for a resilient and robust
18 electric grid and for the environment. Any rate plan that recalculates the buyback for solar

¹¹ Stebbins, Samuel (2022) How Georgia's Population Will Change in the Next 20 Years, **The Center Square**, https://www.thecentersquare.com/georgia/how-georgia-s-population-will-change-in-the-next-20-years/article_1fdab962-80de-5efe-8711-33296016f3aa.html.

1 based on what is generated at a different rate than what they pay introduces confusion and
2 suspicion.

3 **Q29: DO YOU AGREE WITH AHMAD FARUQUI'S REFORMED VIEWS ON NET**
4 **ENERGY METERING?**

5 A29: Yes. As you know, in 2019 the esteemed Dr. Ahmad Faruqui testified on behalf of Georgia
6 Power that net metering could cause a cost shift from solar owner to non-solar owner in
7 the rate base introducing the question of equity in the rates and revenue destabilization for
8 the company.

9 I draw your attention to the September 27, 2022 Issue of *PV Magazine*¹² to the
10 article entitled "Why did I reform my views on Net Energy Metering (NEM)?" by Dr.
11 Ahmad Faruqui. In the article Dr. Faruqui claimed his position against NEM policies had
12 him standing on the wrong side of history. He said people "rich and poor, want to install
13 solar panels. They enhance affordability and green energy. When paired with batteries,
14 they enhance local resilience. They lower investments in the distribution and transmission
15 system."

16 In the article, Dr. Faruqui specifically states "I also believe that states where solar
17 deployment is in the early stages, and where less than 5% of customers have deployed solar
18 roofs are at a very different stage of the game and should stick with NEM in its current
19 form."

¹² Faruqui, Ahmad (2022) Why did I reform my views on net energy metering (NEM)? **PV Magazine**, <https://pv-magazine-usa.com/202209/27/why-did-i-reform-my-views-on-net-energy-metering-nem/>.

**Q30: HAVE YOU SEEN ANY EVIDENCE THAT DISTRIBUTED SOLAR HAS
REDUCED DISTRIBUTION COSTS?**

A30: Yes. I had the opportunity to attend the National Association of State Energy Officials conference in St. Petersburg, Florida Wednesday, October 12, where Dr. Justin M. Hill, Ph.D. PE, Senior Research Engineer for Southern Company Services Inc. was presenting the results on two solar microgrid residential projects for moderate income neighborhoods in Alabama and Georgia.¹³ The solar microgrids were successful in their ability to island full neighborhoods - completely separating from the electric grids for periods. Dr. Hill stated, "There was significant reduction in distribution cost required including substation transformer. For the Alabama project the reduction in required equipment size was 50%, freeing up capacity for other loads."

Q31: WHAT ARE THE CONCLUSIONS OF YOUR ANALYSIS?

A31: A lot has been said in this docket about there being a cost shift from solar homeowner to the rest of the ratepayers. My testimony should put significant doubt on the Company's position. Furthermore, it should be recognized that if the value of the solar generation paid by the majority of Georgia utilities remains at the low marginal value that it has been for the past decade, then we can expect relatively few solar homes to be advanced in Georgia. This means that the majority of the IRS federal tax credit (recently restored back to 30% by the Inflation Reduction Act) supported by the American taxpayer, including Georgians, will go to US citizens outside of the state of Georgia. It will be ironic that a position

¹³ Hill, Justin (October 2022) Smart Neighborhoods (aka Connected Communities), Presentation at National Association of State Energy Officials, <https://annualmeeting.naseo.org/data/energymeetings/presentations/Hill.pdf>.

1 maintained by the policy of this Commission, would result in the shift of up to \$1 billion
2 in taxpayer-funded investment tax credits (the amount of credit that would be availed to
3 295,000 solar homeowners as per the Drawdown Georgia goal) away from Georgians to
4 U.S. taxpayers outside the state of Georgia. (See AMH-Exhibit-2).

5 In conclusion, if distributed solar helps lower the cost for the entire electric system,
6 that cannot be considered as a cost shift subsidy. In fact, the cost savings of between \$300
7 and \$400 per solar home in Georgia suggests the Commission, through Georgia Power,
8 should be doing all it can to see that consumers can put solar on their roofs to help lower
9 costs for all ratepayers. Ensuring access to net metering one-for-one credit for all solar at
10 the load is the simplest way to proceed.

11 **Q32: DOES THIS CONCLUDE YOUR TESTIMONY?**

12 A32: Yes.

Attachments

AMH-Exhibit-1

ALDEN MOINET HATHAWAY II, P.E., C.E.M.

4025 Pinebrook Circle

Cumming, Georgia 30028

email: ahathaway@sterlingplanet.com

PHONE: 540-207-3142

SUMMARY of EXPERIENCE

An energy visionary, Alden Hathaway, possesses the conviction that we have the energy technologies to solve our environmental problems while saving money and energy for all.

Mr. Hathaway is Program Director for Power and Renewables, for Pond and Company where he leads the company in renewable energy markets and consulting initiatives with utilities, governmental and corporate customers. Mr. Hathaway is applying his nearly 40 years of energy and renewable energy experience to assist Pond's traditional customers transition and succeed in the emerging market for clean energy.

Mr. Hathaway is an energy and environmental marketing and professional engineer whose career spans over thirty-nine years of experience in energy: sales/marketing; training and project management. His particular skills include:

- National Account/ Utility/Government Marketing and Green Power Programs
- Product Development and Sales
- Marketing Management, Training and Consulting
- Domestic and International Small and Large Renewable Power Plant Development

EXPERIENCE:

Sterling Planet, Inc and Sterling Energy Assets, LLC: *Sr. Vice President, Business Development:* Alpharetta, GA 2021 – Present. Returned under special assignment to develop, patent, and launch a new Solar program for the commercial market.

Pond and Company: *Program Director Power and Renewables:* Peachtree Corners, GA, Dec, 2020 – 2021. Develop new Power Initiatives for utilities supporting transmission and distribution needs incorporating new renewable sources. Support renewable power development including microgrids for utilities, federal govt and commercial customers. Support renewable integration into other Pond businesses, including buildings, transportation and natural gas companies.

Sterling Planet, Inc and Sterling Energy Assets, LLC: *Sr. Vice President, Business Development:* Alpharetta, GA 2007 – 2020. Develop new programs and products for Electricity and Environmental Markets, including Renewable Energy Certificates, Greenhouse Gas Offsets, Energy Efficiency Credits and Utility Energy Efficiency and National account Sustainability Programs. Integrate new products into Sterling offerings to offer customers coordinated approach to climate neutral sustainability goals. Work with the Chairman to expand Sterling's energy and environmental programs and opportunities into the International Arena, including developing world renewable energy projects and services.

Solar Light for Africa: *Founding Board Member:* Melbourne, FL—1997 - Present. Cofounded and launched Solar Lighting program in rural Africa which successfully installed over 2500 solar systems in Uganda, Tanzania, Rwanda, Ethiopia, Sudan, Ghana, Congo, Sierra Leone and Liberia over 20 years.

AMH-Exhibit-1

ERT, Inc: *Director, EcoPower® Programs: Washington, DC --1999 - 2007.* Coordinated Environmental Resources Trust (ERT) EcoPower® and Renewable Energy Certification Program for National Accounts, Utilities, Federal, State and Municipal Governments; Helped launch EPA Green Power Partnership Program by developing National REC Response; The first to Certify National RECs/Issue REC Standard 2002; Signed the first Utility REC Contract for Government green power.

SOLAREX: *Director of Marketing and Distribution: Frederick, MD—1996 - 1997.* Managed a \$1MM budget for the Marketing and Distribution Departments and six direct reports. Coordinated Distributor Program for over 70 distributors in 60 countries; Product Mgr for Millennia Thin Film Product

ICF Kaiser: *Project Manager: Washington, DC—1994 - 1996 & 1997 - 1999.* Market Launch and Marketing Support for EPA's Green Lights; Energy Star Buildings; Green Power Partnership Programs. Managed Implementation Team of 16 engineers for Green Lights and Energy Star Buildings Partners.

GTE: *Manager, Energy Programs: Sylvania Lighting Division: Danvers, MA, 1991 - 1993*
Managed Sylvania's activities in EPA's Green Lights program by merging activities of Sylvania Lighting Services with manufacturing sales force. Developed energy management packages and acted as energy spokesman for Sylvania Lighting Division.

Senior Lighting Engineer: St. Louis, MO - Washington, DC—1983 - 1991
Technical Advisor to District Sales Manager; responsible for training and assist in managing district sales personnel. Conducted lectures, clinics, and seminars regarding energy and utility rebate opportunities. Liaison to government for efficient lighting legislation and consulted with EPA in developing Green Lights Program.

Georgia Power Company: *Assistant Marketing Engineer: Columbus Georgia--1982-1983*
Managed Manchester District electrical marketing effort. Assisted customers with energy management needs. Responsible for commercial electric revenues.

EDUCATION:

University of Virginia: Charlottesville, Virginia--B.S.E.E. January, 1982

ADVISORY:

Member, White House task force on Global Climate Change, 1993 - 1994

Member, ASHRAE/IES Energy Management Committee, 1992 - 1993

AWARDS:

U.S. Patent, Provisional, 2017: DC Lighting System

Legend in Energy Recognition, 2013: Recognized by the Association of Energy Engineers

U.S. Patent, 2013: Method and Apparatus for Determining Energy Savings by Using a Baseline Energy Use Model

Regional Wind Advocacy Award - 2005: USDOE Wind Powering America – Recognized for support of Wind Power in area Air Pollution Compliance plans;

Outstanding Environmental Volunteer - 2000: Loudoun County– Recognized for solar power plant development at Franklin Park Performing Arts Center;

ICF Service Award, 1995: Recognized for the market development of the ENERGY STAR Buildings Program.

U.S. Patent, 1991: "Master-Satellite Fluorescent Lighting System"

Lighting Engineer Award of Merit, 1988: GTE Sylvania – For Marketing of Octron T-8 System

AMH-Exhibit-1

CERTIFICATION:

Georgia Engineer In Training (EIT) April, 1983

Georgia Professional Engineer (P.E.) Electrical Power Discipline June, 2010 – Present

South Carolina Professional Engineer (P.E.), Electrical Power Discipline May, 2017 - Present

Certified Energy Manager (CEM) April 1993 - Present

PUBLICATIONS:

Two books and twenty+ articles published (trade magazines, conference proceedings and technical journals):

"New Plans to Lighten Building Construction Costs," Consulting Specifying Engineer, News and Review Section, May, 1989.

"Lighting Efficiency: A Simple Solution to a Complex Problem," Public Utilities Fortnightly, June, 1990.

"Tuning for Energy Efficiency" Intelligent Buildings Quarterly, February, 1992.

"Master/Satellite Lighting Systems Provide High Energy Savings" Mainlighter, March, 1992.

"Global Warming in the Office Environment," Mainlighter, July, 1992.

"Solar Assisted Lighting" Today's Lighting Distributor, a NAILD publication, June, 1993.

"Tuning for Energy Efficiency" Energy Engineering, September, 1993

"The Environmental Impact of Energy Efficiency" Strategic Planning for Energy and the Environment, March, 1994.

"Financing Options for Energy Efficient Upgrades" Building Operating Management, September, 1994.

"A Lighting Upgrade Must, parabolic luminaires provide energy-efficient, uniform illumination" Green Lights and Energy Star Update, October, 1995

"HVAC Load Reductions Lower Energy Bills" Green Lights and Energy Star Update, July, 1995.

"The Link between Lighting and Cooling" Maintenance Solutions, July, 1995.

"Solar Assisted Lighting for Developing Nations" World Aid Directory, April, 1997.

"Solar Powered Buildings: Power Plants for the 21st Century" Presentation and Article at the World Energy Engineering Congress, Atlanta and Proceedings, November, 1997.

"Commercial Buildings as Power Plants in a Deregulated Utility Market" Proceedings for Solar '98, American Solar Energy Society, June, 1998.

"Changing the Facility Energy Load Profile (A Rate Cost Mitigation Strategy to Prepare for Utility Deregulation)" Energy User News, November, 1998, (Co-author: David Smith, Director Facilities, MCG)

Building an Affordable Solar Home - Solving a Nation's Quest for Sensible Energy and Environmental

Direct Testimony of Alden M. Hathaway II.
Southern Alliance for Clean Energy & Southface Energy Institute, Inc.
Georgia PSC, Docket No. 44280

AMH-Exhibit-1

Strategy, 2004 - Self-published book - building and fine tuning of the Hathaway Solar Patriot Home.

“Empowering Africa – How Solar Energy Advocates are Bringing Light and Hope to Rural East Africans”
Solar Today, July/August 2005 (Co-author: Charolett Baker, Executive Director, Solar Light for Africa)

“Solar Charging Stations – Key to Reviving American Auto Industry” Solar Today, September/October 2009

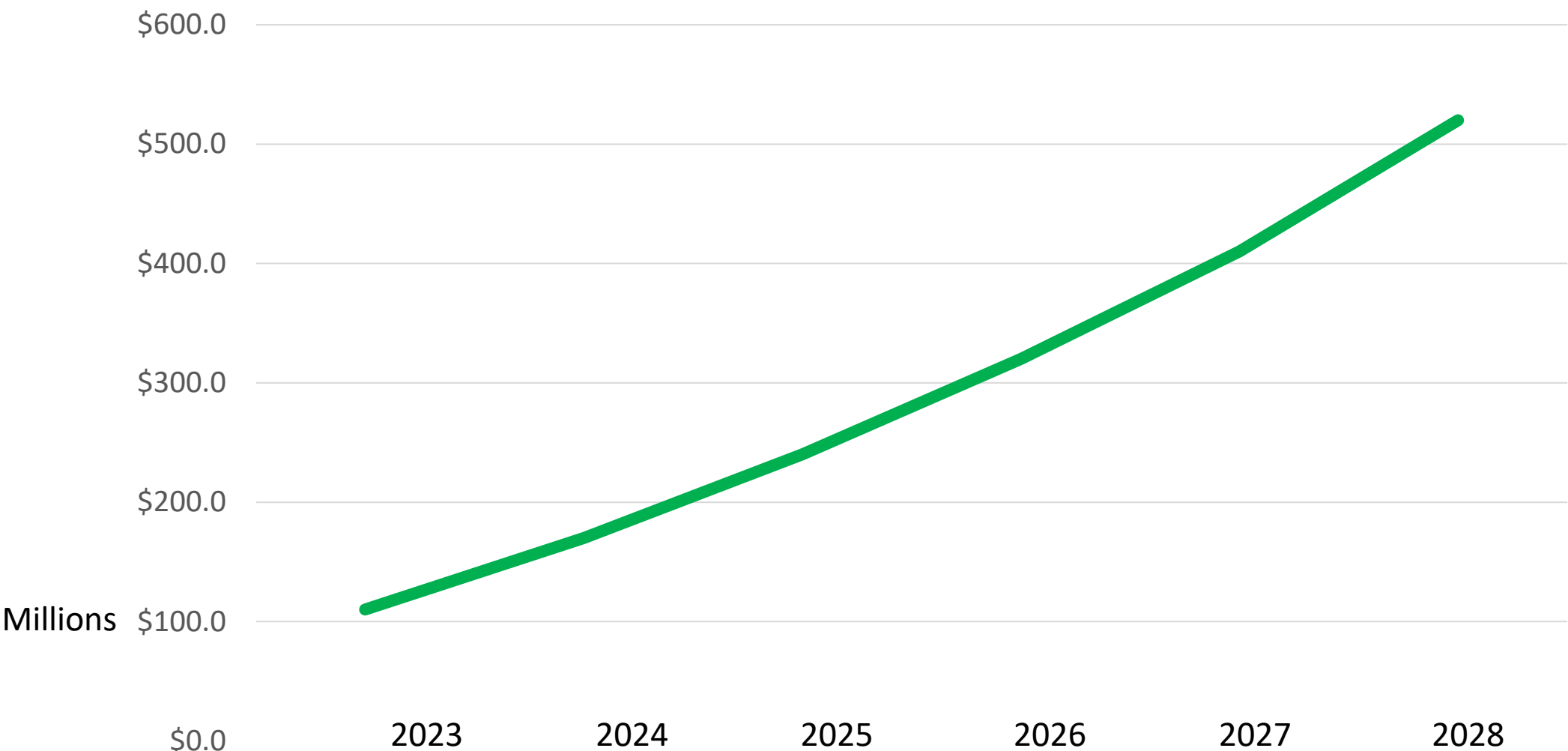
“Improving System Load Factor - A Recipe for Containing Electric Rates and Growing Renewable Energy”
North American Clean Energy, Jan, 2013

“Measuring and Rewarding Energy Efficiency” North American Clean Energy, May, 2013 (co-author: Govi Rao, President of Noveda Technologies)

“A Call for Net Zero Energy” North American Clean Energy, Jan, 2016
<http://www.nacleanenergy.com/articles/22155/a-call-for-net-zero-energy>

Energy Independence – An Individual Pursuit for Energy Freedom, May, 2022, River Publishing, Book released for Association of Engineers (co-author: Tripp Hathaway)

Tax Shift of Funds to Other States from Georgia Citizens Each Year Solar NEM Is Unavailable



Based on Georgia Drawdown goal of 295,000 Solar Rooftops by 2028 at \$6,000 IRS Tax Credit per Installation

1 BY MR. DOWDY:

2 Q Mr. Hathaway, did you also cause to have
3 prefiled two exhibits which were prefiled as AMH Exhibit 1
4 and 2?

5 A (Witness Hathaway) I did.

6 MR. DOWDY: Madam Chairman, I would ask that
7 the exhibits AMH Exhibit 1 and 2 be marked as hearing
8 Exhibits SS-12 and 13.

9 MADAM CHAIR PRIDEMORE: So marked.

10 (The documents referred to were marked for
11 identification as SACE and Southface Exhibits 12 and
12 13.)

13 BY MR. DOWDY:

14 Q Dr. Brown, would you give your summary.

15 A (Witness Brown) Yes. Thank you.

16 DR. BROWN: Madam Chair and Commissioners, it
17 is my privilege and honor to provide you with a
18 summary of my prefiled testimony. And it's a
19 pleasure to talk with you again about customer-sided
20 solar and about net metering in Georgia and across
21 the U.S.

22 So I'd like to begin with a bit of level
23 setting of facts. First, net metering policies began
24 in 1980 in Idaho. Now, that was way back when we had
25 analog meters. And when they turned to the right,

1 you were consuming and paying. And when they turned
2 to the left, you were getting a rebate at retail
3 price for the electricity that you were providing to
4 the grid.

5 Now, today we have very different meters. They
6 are digital. And, yet, the same principle of
7 crediting the excess electricity at retail price is
8 the prevalent pricing approach. It is currently used
9 in 33 states.

10 Over the last decade, states have continued to
11 adopt this net energy metering. We have Oregon
12 coming on board, North and South Carolina. And at
13 least one of these states, the state of
14 Massachusetts, provides a payback rate which exceeds
15 the retail rate. It has an adder to value the
16 additional resources and benefits that solar can
17 provide.

18 Out of the seven states in the southeast, North
19 Carolina, South Carolina and Florida have net
20 metering tariffs. I appreciate that this may change
21 in North Carolina and could change in any number of
22 the states across the country, either being added or
23 subtracted or altered to successor tariffs. There
24 are many optional tariffs that are being debated all
25 across the country.

1 But if we consider that the Carolinas and
2 Florida have had retail metering for awhile, these --
3 it's interesting that these same three states average
4 about 1 percent of residential customers with
5 distributed solar, which is very large relative to
6 their neighboring states in the southeast. So they
7 are the leaders in the southeast.

8 The other four southeastern states,
9 Mississippi, Alabama, Georgia and Tennessee, do not
10 allow one-to-one net metering for electricity
11 supplied back to the grid. And they are all in the
12 bottom eight states across the country, in terms of
13 rooftop solar penetration.

14 These statistics are meant to try to convince
15 you that having something like net energy metering is
16 the only way we're going to grow our penetration of
17 rooftop solar. It doesn't occur in the absence of
18 supporting tariffs.

19 The national average penetration of
20 customer-sided solar is about 1.9 percent. And if
21 you take a look at Exhibit 1.9, you can see that
22 Georgia is 43rd.

23 We have had 30 percent investment tax credits
24 for customer-sided solar systems since 2006,
25 following the 2005 Energy Policy Act. Yet, only

1 about 2.2 percent of Georgia Power's electricity
2 customers have distributed solar.

3 The principal reason is the absence of net
4 metering for most of the years since the 30 percent
5 investment tax credits have been available. So,
6 again, without supporting tariffs, the investment tax
7 credits have not made much of a difference.

8 Most states across the nation also do not have
9 caps, including, for instance, in our region,
10 Alabama, Florida, North Carolina and Tennessee. Caps
11 on net metering do exist in South Carolina at
12 2 percent and in Mississippi at 3 percent, but none
13 of them, either in the southeast or across the
14 country, are as limiting as the Georgia cap of
15 .2 percent.

16 That concludes my fact-based little list of
17 statistics. I want to turn now to my three
18 recommendations. These are based on my analysis of
19 net metering policies across the country and Georgia
20 Power's proposal to the Commission.

21 The first recommendation is that the Commission
22 should order Georgia Power to reinstate the renewable
23 and nonrenewable RNR monthly netting tariff without a
24 cap for the next three years.

25 But the company has not given any information

1 in its docket to cause me to change my mind about the
2 value of net metering to Georgia Power customers or
3 the possible existence of a meaningful cost shift.
4 Thus, my recommendation to the Commission has not
5 changed since I testified at the IRP hearing a couple
6 of months ago.

7 I continue to doubt the existence of a cost
8 shift and its materiality. Having an unlimited cap
9 for the next three years will enable customer-sided
10 solar resources to support system reliability,
11 enhance local economic development, and it will allow
12 participation of Georgia customers in the 30 percent
13 investment tax credit we've been talking about as
14 part of the Inflation Reduction Act.

15 Georgia Power Company is not at a level of
16 solar penetration that warrants valuing excess
17 customer generation at anything less than a retail
18 rate.

19 Recall in my testimony and in my previous IRP
20 testimony the citation I made to the Lawrence
21 Berkeley National Lab study that said only when a
22 state has reached about 10 percent solar, that's a
23 combination of rooftop and utility-scale and
24 community solar, would you possibly begin to see the
25 existence of a cost shift.

1 One of the reasons for a threshold like
2 10 percent is the fact that at that point you begin
3 to see the movement of the peak hour of consumption
4 of the utility into the evening. So California's
5 peak has moved into the evening. It's now around
6 9:00. Its peak extends to 9:00 p.m.

7 Our peak, as you know, remains the same and
8 ends at about 7:00 p.m. So solar resources are
9 provided at hours that are still coincident with peak
10 and they will likely do that until we have about 10
11 percent solar.

12 Without a tariff that provides reasonable
13 compensation, investment economics for rooftop solar
14 in Georgia, even with the ITC, the investment tax
15 credit, aren't favorable. And they are not
16 accessible to many customers.

17 There's no support for the company's statement
18 or for Dr. Gattie's statement that because of the
19 recent passage of the Federal Inflation Reduction Act
20 there is no need to further incentivize
21 behind-the-meter solar.

22 Comparing rates of adoption of distributed
23 solar across the U.S. clearly shows that customers
24 are more likely to make local investments in solar on
25 their own property when they are provided with

1 enabling rate structures that fairly compensate them
2 for the value of their investment.

3 Without a net energy metering tariff, Georgia
4 Power customers will continue to invest very little
5 in distributed solar, but will continue to pay an
6 enormous amount -- hundreds of millions of dollars --
7 in taxes that will be sent to residents of other
8 states who are putting rooftop solar on their homes
9 and buildings.

10 Second recommendation is a cost of service
11 study should be conducted by the company and provided
12 to the Commission prior to the next rate case. Not
13 all of the benefits of customer-sided solar are
14 accounted for in the cost shift analysis and Lee
15 Evans' and Larry Legg's testimony, including, for
16 instance, its positive impact on health, climate,
17 clean water, and resilience.

18 I understand that some of those are not
19 included in the benefit cost approach that's been
20 adopted. But, in addition, this cost shift analysis
21 does not include an assessment of the cost to serve
22 solar participants versus the cost to serve solar
23 nonparticipants. It is likely that a cost of service
24 study will reveal it costs less for the Georgia Power
25 Company to serve net metering customers than to serve

1 nonsolar customers.

2 If I were on the board of the TVA, I would
3 wonder why the pilot data was sufficient to allow TVA
4 to estimate the details of a cost shift study, but
5 did not allow TVA to estimate the cost of service for
6 participants versus nonparticipants. Why was the
7 data not sufficient to do that, but it could do the
8 cost shift assessment?

9 Such a study might also consider the nearness
10 of customer-sided solar to demand loads, which is a
11 really important factor in determining the locational
12 value streams of generation assets. Different points
13 in the grid have different transfer capability due to
14 voltage, thermal security, stability constraints.
15 Locational value depends also on the hour of the day
16 and the season of the year.

17 Are solar customers deferring the need for the
18 company to provide them with expensive on-peak power
19 or are they providing less expensive off-peak power?
20 My colleague Alden Hathaway will address that
21 question, but first I'll continue.

22 Given the significant increase in transmission
23 and distribution investments being proposed here for
24 the company, requiring the company to conduct a cost
25 of service study that considers the cost

1 effectiveness of customer-located investments is both
2 prudent and necessary.

3 Third recommendation, last one, is that the
4 proposed interconnection fee for participation in the
5 RNR tariff should be reduced -- excuse me -- because
6 it is excessive based on my assessment of practices
7 elsewhere. If you'll turn to Exhibit 5, you'll see a
8 great quad chart that shows where Georgia Power's
9 proposed \$200 interconnection fee is located in the
10 upper right-hand corner of the top quad on that
11 chart. It is higher than any of the peer utilities'
12 interconnection fees shown on that chart, which is --
13 has about a dozen or 15 examples. I agree with the
14 staff proposal that it be reduced to 100.

15 In addition, the fees should be waived for
16 income-qualified customers because of their limited
17 access to capital and the historically low levels of
18 participation in the RNR tariff and rooftop solar
19 programs.

20 There are also other programs that Georgia
21 Power could offer to increase access to solar by low-
22 and moderate-income households, such as on-bill
23 financing and others you've heard about, including
24 the new Mississippi program that's just been
25 launched.

1 The second supplemental rebuttal testimony of
2 Lee Evans and Larry Legg notes that their estimate of
3 the company's alleged cost shift from RNR
4 participants to nonparticipants has been corrected.
5 It is now estimated by them to be \$826 per RNR
6 customer and not 1,356.

7 So let's work with this number a bit. \$826 per
8 RNR customer. I'm going to be doing this in a way
9 that Commissioner Echols did yesterday with some of
10 his calculations. Simple, but very impactful.

11 Let's also consider the results of Duke
12 Energy's embedded cost shift study recently published
13 of the Duke Energy Carolina system, which estimates
14 that the cost to serve net metering customers is \$651
15 less than the cost to serve other customers.

16 So now we subtract those two numbers, one from
17 the other, and the cost shift estimate becomes
18 something more like \$175 a year per RNR participant.

19 Now, consider -- for each of the 5,000
20 participants, consider the 2.3 million
21 nonparticipating Georgia Power customers and spread
22 that \$175 for the 5,000 customers over the
23 2.3 million nonparticipating customers, and you get
24 an estimate of an alleged annual cost shift of
25 38 cents per nonparticipant. Thirty-eight cents is

1 immaterial, inconsequential, and, indeed, de minimus.

2 As Commissioner Echols noted yesterday in
3 comparison, the 5,000 Georgia Power customers
4 participating in the RNR pilot program invested about
5 \$100 million to generate clean and locally resilient
6 electricity that benefits all of Georgia Power's
7 customers.

8 MR. MARZO: Excuse me. Madam Chair, just
9 wondering if we're going beyond what a summary of
10 testimony is supposed to be.

11 DR. BROWN: I only have one paragraph left and
12 it's -- I'm leaving that --

13 MR. MARZO: And I was trying to be very open,
14 in terms of making this objection. I didn't know how
15 much more we had left. But I think we're kind of
16 introducing concepts outside of the direct testimony.

17 MADAM CHAIR PRIDEMORE: It is much more
18 in-depth than what we typically receive in a summary.
19 And I'm going to overrule you and give some credence
20 to Dr. Brown. She's just got a little bit more to
21 say.

22 DR. BROWN: Thank you. I apologize for taking
23 so long. I only want to conclude now.

24 It's been my honor and pleasure to speak before
25 you about the value of continuing the RNR monthly

1 netting tariff. I applaud the Commission's
2 leadership in the IRP earlier this year where you
3 ordered the company to evaluate demand-side resources
4 on a competitive basis and a level playing field in
5 the modeling for the next IRP. That will help also
6 to better understand the role that rooftop solar can
7 play.

8 I urge you to continue that leadership by
9 supporting the continuation of the RNR program
10 uncapped between now and the next IRP, during which
11 time the company can bring you a cost of service
12 study and competitive modeling of behind-the-meter
13 resources to inform program design and rate design
14 going forward.

15 Thank you, Commissioners, for your time and
16 consideration. This concludes my summary and I'm
17 happy to take any questions now or perhaps after the
18 next summary.

19 BY MR. DOWDY:

20 Q Thank you, Dr. Brown. We're going to let --
21 Mr. Hathaway, if you would give your summary now.

22 A Thank you.

23 MR. HATHAWAY: Madam Chairwoman and
24 distinguished members of the Georgia Public Service
25 Commission, it is truly a pleasure to be with you

1 today.

2 I wish to congratulate the Georgia Public
3 Service Commission for steering our electric industry
4 to a cleaner, lower-carbon, intensive system as the
5 best way to recruit companies to Georgia,
6 particularly those that are involved in the clean
7 energy technology business. Manufacturing companies
8 like SK Innovations, Kia, Rivian and Hyundai, as well
9 as Huanwa Solar and Mitsubishi, Dacon and others,
10 like Apple, Meta, Microsoft, Amazon, Google, and many
11 others that are locating here for a lower-carbon
12 goal, which they can get simply by locating to
13 Georgia because Georgia's reduced its carbon
14 emissions nearly in half in the last two decades. So
15 these companies, by locating here, they get an
16 automatic reduction in their carbon emissions.

17 But, Commissioners, there is a cost that
18 investing in clean energy generation technology levy
19 on the system, especially if that investment is made
20 on only the supply side. That cost is seen in rising
21 electric rates, which we have seen push Georgia to
22 the second highest in the southeast. Only Florida
23 rates are higher.

24 Fortunately, there is plenty of room on the
25 demand-side equation where Georgia can continue to

1 invest, or I would say simply allow investment that
2 will help put downward pressure on electric rates.

3 A measure of what I'm speaking about, this
4 opportunity can be expressed simply in terms of load
5 factor. By investing mostly in generating capacity,
6 and not so much on the demand side of the meter,
7 Georgia has a lower-than-average load factor compared
8 to the nation, and even in the southeast. Load
9 factor can best be described as how efficient the
10 electric system operates, the generation,
11 transmission, distribution based on the load --
12 combined load factor of all customers it serves.

13 If a load factor is high, say 60 to 70 percent
14 range, it means that peak demand has been tamed
15 relative to overall energy use, causing the
16 utilization of the generating, transmission,
17 distribution assets to be utilized more fully,
18 70 percent full load.

19 On the other hand, a load factor in the 30 to
20 40 percent range means peak demand has not been tamed
21 and results in a higher capacity than necessary to
22 provide power to run the system. The average load
23 factor for the U.S. electric system is in the low 50
24 percent range, while Georgia's electric system barely
25 reaches 40 percent.

1 Commissioners, over the course of the next
2 several decades, from the 1970s to 2000s, the Central
3 Vermont Public Service Commission -- I'm sorry,
4 Central Vermont Public Service, which is now Green
5 Mountain Power, showed that a systematic investment
6 on the demand side of the electric system, including
7 distribution, generation -- and that includes
8 distributed generation, such as solar -- improved
9 their system load factor from 55 percent to 70
10 percent, with a corresponding reduction in electric
11 operating costs estimated to be about 4 or 5 percent.

12 This ratio of reduced operating costs
13 extrapolated to Georgia's electric system, if we were
14 to embark on the same course, if we improve from 40
15 percent to 70 percent, could be as much as 10
16 percent. This 10 percent savings, if we applied it
17 to Georgia electric rates, moves the state higher up
18 in its rankings of lowest electric rates in the
19 country, and even in the southeast. And on a macro
20 scale, it could mean a savings on the electric bill
21 of nearly \$100 per year per Georgia ratepayer.

22 In an article called The Power of Five Percent,
23 Ahmad Faruqui, a witness here testifying before you
24 all at this very Commission just three years ago, and
25 I think at the -- at the request of the Southern

1 Company, against offering net metering and has since
2 had a very public turnaround about net metering,
3 tells us that just a 5 percent reduction in peak
4 demand across the country would yield \$35 billion in
5 electricity costs for generation, transmission, and
6 distribution assets.

7 Commissioners, the Georgia electric system
8 still peaks in the afternoon, around 4:00 to 5:00
9 p.m, a time when solar in Georgia, because of the
10 daylight savings time at the western end of the
11 eastern time zone, is also within 80 percent of its
12 solar peak. The actual solar peak being about 2:10,
13 2:20 p.m. in the afternoon.

14 Therefore, we have a nearly perfect match for
15 solar at the load, reducing peak demand. It is less
16 expensive at the load because the electrons do not
17 travel back up the transmission lines to the
18 generating station, but they stay and support the
19 local electric circuits servings the loads.

20 If I were to apply this ratio that Ahmad
21 Faruqui puts in his article to the Georgia population
22 of 10.8 million to the national population, which is
23 350 million, that ratio applied to the 5 percent
24 reduction that Ahmad Faruqui speaks about, and the
25 realization that Georgia Drawdown goal of 295,000

1 solar roofs by the end of the decade is about 5
2 percent of our peak load demand reduction. It helps
3 us to see that an average savings to the rate base of
4 about \$330 for every rooftop that puts solar on it
5 would go to the entire rate base across the electric
6 system.

7 This is very close to the same number that, I
8 think, SEIA and senior director of utility regulation
9 and policy testified to a couple of weeks ago. But I
10 showed you how we can use this analysis from the
11 well-respected former witness Ahmad Faruqui to arrive
12 at the same number. If we could apply this, it could
13 reach over to \$100 million per year in electric cost
14 savings, putting significant downward pressure on
15 electric rates, all ratepayers across the board.

16 All the Georgia Public Service Commission needs
17 to do is to allow net metering on a one-to-one basis
18 to occur so that solar homeowners can save enough on
19 their electric bill to make the solar investment and
20 then all ratepayers would benefit from this \$330 net
21 savings per year per solar household. This is not a
22 cost shift from solar homeowner to nonsolar
23 homeowner, but a benefit for all.

24 We have heard testimony here that the IRA bill
25 passed by the U.S. Congress will issue new incentives

1 for clean energy, including solar. But,
2 Commissioners, please remember that for solar
3 rooftops the IRA bill simply restored the 30 percent
4 tax credit for -- that solar homeowners -- that
5 homeowners could receive in 2019 and before. In
6 fact, the 30 percent ITC was available for the --
7 most of the entire decade 2011 to 2020. Yet, we've
8 seen very little Georgia solar rooftops been
9 implemented and that is because without net metering,
10 monthly netting of some sort, solar is not currently
11 economical to most Georgians.

12 Commissioners, I know this because when I built
13 our solar home in 2014, 2015, I investigated where to
14 build it so that I could make a return on investment.
15 Even with the 30 percent tax credit, I could only
16 achieve a two-and-half percent rate of return with
17 the energy value from Georgia Power.

18 So instead, we opted for land served by Georgia
19 EMC that offered not -- monthly netting. The
20 difference offers us a higher average 7.8 percent
21 rate of return.

22 As most financial advisers would suggest, there
23 are better places to put your money than for a return
24 less than 3 percent. We opted for a much higher
25 percent rate. But those people that don't have that

1 choice will not opt to invest in solar at such a low
2 return.

3 This sets up what I consider to be an
4 unfortunate choice that we have, especially given the
5 testimony we have had about the coming opportunities
6 that exist in the new IRA bill and other things that
7 are occurring, and that is this. I direct you to my
8 final exhibit that I have provided to you.

9 If net metering is not adopted, then we will be
10 witnessing one of the largest federal tax shifts
11 Georgia and Georgia taxpayers have ever seen.
12 Without net metering, those 295,000 solar roofs that
13 are part of the Georgia Drawdown goal do not happen.

14 And the nearly \$250 million per year in IRA
15 funds, tax credits on those 295,000 solar rooftops,
16 on average is transferred from Georgia taxpayers to
17 solar investors in other states where there is net
18 metering.

19 Please, Commissioners, do not let it happen.
20 Put one-to-one solar net metering in place and let
21 Georgians choose to keep their tax dollars in the
22 state and reduce the cost of electricity for
23 everyone.

24 It has been a truly proud pleasure and honor to
25 speak with you today. Happy holidays and a blessed

1 Christmas to you.

2 MR. DOWDY: Thank you, Mr. Hathaway.

3 Madam Chairman, the witnesses, this panel, is
4 available for your questions and cross-examination.

5 MADAM CHAIR PRIDEMORE: Questions from
6 Commissioners?

7 Commissioner Echols.

8 VICE-CHAIRMAN ECHOLS: Distinguished panel, I
9 should say, thank you for being here. This tax shift
10 that you just mentioned, Mr. Hathaway, I have not --
11 I have not thought about that. The leaving --
12 leaving the money on the table that we could draw
13 down, so to speak.

14 So the example I gave yesterday was about the
15 economic development, you know, impact, but this is
16 completely different. So question for either of you:
17 If it's so self-evident that net metering is a bad
18 thing, why are EMCs -- why are some EMCs -- why have
19 they embraced it?

20 Why did Jackson embrace it or Sawnee embrace it
21 or others? Are they just not seeing -- seeing things
22 accurately?

23 Why would they do something that is so
24 counterintuitive and damaging, possibly damaging to
25 their system?

1 MR. HATHAWAY: I imagine you're directing that
2 question to me, Commissioner Echols.

3 VICE-CHAIRMAN ECHOLS: Because you're a Sawnee
4 customer.

5 MR. HATHAWAY: I am a Sawnee customer. I
6 innately believe it's good for their system to reduce
7 peak demand on their system. Because I believe EMCs
8 get charged extremely high amounts for power they
9 could buy at peak on capacity. And so they put in
10 place -- policies in place to help support customers
11 that will help them reduce their peak demand. And so
12 that's one of the reasons why I think they offer it.

13 VICE-CHAIRMAN ECHOLS: Okay. Thank you.

14 Dr. Brown, just one question for you. You
15 mentioned this -- this shifting of the peak and
16 the -- I guess, if -- I mean, we've had a lot of fun
17 over the last couple of days with cars and movies and
18 animals and math.

19 And I guess it -- let's just -- let's just say
20 that the 10 percent that causes the peak to shift is
21 a wolf and that that -- let's just make the
22 assumption that it is a wolf and that it would damage
23 -- it would damage our system. It would shift our
24 peak. We'd have to -- whatever -- I don't know all
25 the things that we'd have to do to counteract that.

1 But let's just assume that's true. Why -- why
2 would we keep kind of going up to that line; right?

3 If it's true that that would happen, why would
4 we keep moving in that direction? And how -- you
5 know, how could our Commission be, you know, prudent
6 in making sure we don't go too far and create these
7 problems?

8 DR. BROWN: So over the next three years you
9 could put in place 75,000 new systems or something
10 like that and that will not even get you anywhere
11 near the 10 percent total, but in three years' time,
12 the world is going to be different. Batteries are
13 going to play such a big role.

14 And so you will have an opportunity while we're
15 getting the rooftop solar in place to figure out how
16 batteries and electric vehicles are going to change
17 the complex of electrification. So I don't think
18 we're ever going to be at the situation where
19 California is where they just have rooftop solar.

20 We're going to be blessed with a whole lot of
21 new gadgets in our houses. And I don't mean to say
22 that we did the right thing because I'm kind of -- I
23 mean, obviously I think we should be leading more
24 than lagging. But this three-year period gives us a
25 chance, build up, it's not going to cost us anything,

1 and get ready for this much bigger challenge and
2 opportunity with solar -- with storage.

3 VICE-CHAIRMAN ECHOLS: Thank you so much.

4 DR. BROWN: Oh, I did want to add -- since you
5 asked sort of to Alden about the -- how it was
6 eye-opening to consider how much tax revenues could
7 go to other states if we don't get our fair share.
8 My Exhibit 4 shows how much we have already sent to
9 other states by being behind on rooftop solar.

10 And the number is \$429 million we have already
11 lost. Our citizens have been subsidizing other
12 states to the tune of 429 million of investment tax
13 credits that other states have collected from the
14 taxes we've paid.

15 MADAM CHAIR PRIDEMORE: Questions from other
16 Commissioners?

17 (No response.)

18 MADAM CHAIR PRIDEMORE: Okay. Americans for
19 Affordable Clean Energy.

20 MR. GALLOWAY: No questions, Madam Chair.

21 MADAM CHAIR PRIDEMORE: Georgia Coalition of
22 Local Governments.

23 MS. BROWN: No questions, Madam Chair.

24 MADAM CHAIR PRIDEMORE: GIPL.

25 MS. WHITFIELD: No questions, Madam Chair.

1 MADAM CHAIR PRIDEMORE: GA Solar.

2 MR. MORELAND: No questions.

3 MADAM CHAIR PRIDEMORE: GASEIA.

4 MR. THOMASSON: No questions.

5 MADAM CHAIR PRIDEMORE: MARTA.

6 MS. STURM: No questions.

7 MADAM CHAIR PRIDEMORE: Sierra Club.

8 MS. ARIZA: No questions.

9 MADAM CHAIR PRIDEMORE: Georgia Public Service
10 Commission.

11 MR. THOMAS: No questions.

12 MADAM CHAIR PRIDEMORE: Georgia Power.

13 MR. MARZO: Madam Chair, to avoid retreading
14 ground already tread with other witnesses, we have no
15 questions.

16 MADAM CHAIR PRIDEMORE: Redirect.

17 Considering you only had only one question from
18 a Commissioner, I can't imagine you would want to
19 refute what the esteemed Commissioner Echols had to
20 say in support of your witnesses.

21 MR. DOWDY: I would never do that to any of
22 you.

23 MADAM CHAIR PRIDEMORE: Thank you, sir. Yes.

24 MR. DOWDY: So I will say no redirect. I do
25 ask that the exhibits be moved into the record.

1 MADAM CHAIR PRIDEMORE: Very good. So moved.
2 (SACE and Southface Exhibits 7 through 13 were
3 admitted into evidence.)
4 MR. DOWDY: And the witnesses be excused.
5 MADAM CHAIR PRIDEMORE: The witnessed are
6 excused. Thank you.
7 (Witnesses were excused.)
8 MADAM CHAIR PRIDEMORE: Okay. Last one.
9 Supplemental rebuttal testimony, Lee Evans,
10 Larry Legg.
11 Mr. Hewitson, you may swear in your witnesses
12 once they arrive.
13 MR. HEWITSON: Madam Chair, we left them under
14 oath so I won't even swear them in. I'll -- once
15 they get to the -- to their seats, I'll let them
16 actually sit down and we'll get going.
17 MADAM CHAIR PRIDEMORE: Correct, Mr. Hewitson.
18 Chair apologizes for the oversight.
19 MR. HEWITSON: All right, gentlemen. Please
20 remember that you are still under oath.
21 DIRECT EXAMINATION
22 BY MR. HEWITSON:
23 Q Gentlemen, you prefiled supplemental direct
24 testimony and testified at hearing on November 10th
25 regarding the RNR tariff; is that correct?

1 A (Witness Evans) Yes.

2 A (Witness Legg) Yes.

3 Q On November 21st, did you file or cause to be
4 filed an errata to your supplemental direct testimony?

5 A (Witness Legg) Yes.

6 MR. HEWITSON: And, for the record, I would
7 like to identify the errata as Georgia Power
8 Company's Exhibit GPC 45 and have it admitted into
9 the record.

10 MADAM CHAIR PRIDEMORE: Yes.

11 (The document referred to was marked for
12 identification as GPC Exhibit 45.)

13 (GPC Exhibit 45 was admitted into evidence.)

14 BY MR. HEWITSON:

15 Q Gentlemen, on November 23rd of this year, did
16 you prefile or cause to be prefiled 13 pages of supplemental
17 rebuttal testimony in question-and-answer format in this
18 docket?

19 A (Witness Evans) Yes.

20 A (Witness Legg) Yes.

21 Q Do you have any corrections which you need to
22 make to your prefiled supplemental rebuttal testimony?

23 A (Witness Legg) No.

24 A (Witness Evans) No.

25 Q If I were to ask you the same questions today

1 under oath, would your answers be the same as are set forth
2 in your prefiled testimony?

3 A (Witness Evans) Yes.

4 A (Witness Legg) Yes.

5 MR. HEWITSON: Madam Chair, a copy of the
6 prefiled supplemental testimony of Mr. Evans and
7 Mr. Legg was provided earlier to the court reporter
8 and I now ask that it be copied into the record as if
9 given here today.

10 MADAM CHAIR PRIDEMORE: So moved.

11 (Whereupon, the prefiled direct testimonies of
12 Lee Evans and Larry Legg follows:)

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SUPPLEMENTAL REBUTTAL TESTIMONY OF
LEE EVANS AND LARRY LEGG
ON BEHALF OF
GEORGIA POWER COMPANY
DOCKET NO. 44280

I. INTRODUCTION

Q. PLEASE STATE YOUR NAMES, TITLES, AND BUSINESS ADDRESSES.

A. Lee Evans, Director of Demand Planning & Analysis for Southern Company Services, Inc. (“SCS”). My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

A. Larry T. Legg, Director of Pricing and Rates for Georgia Power Company (“Georgia Power” or the “Company”), 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

Q. MR. LEGG AND MR. EVANS, DID YOU PREVIOUSLY PRESENT DIRECT AND SUPPLEMENTAL DIRECT TESTIMONY AND EXHIBITS ON BEHALF OF GEORGIA POWER IN THIS PROCEEDING?

A. Yes.

Q. ARE YOU PROVIDING ANY EXHIBITS TO YOUR TESTIMONY?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of our testimony is to respond to certain statements and recommendations made by the Georgia Public Service Commission’s (“Commission”) Public Interest Advocacy (“PIA”) Staff and various Intervenors as they relate to the structure and pricing of the Company’s Renewable and Nonrenewable Resources (“RNR”) tariff. That we may not specifically address a particular PIA Staff or intervenor recommendation should not be construed as support for such position.

1 **Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

2 A. Our testimony reaffirms the recommendations in our Supplemental Direct Testimony that
3 the Commission: (1) not expand the RNR monthly netting pilot; and (2) require all future
4 RNR customers to take service under a three-part rate, such as the Company’s Time of
5 Use-Residential Demand (“TOU-RD”) rate. The monthly netting pilot has served its
6 limited purpose in providing a data set for the Company and Commission to consider
7 whether monthly netting provides a reasonable balance between incentivizing customer-
8 owned behind the meter (“BTM”) solar on the RNR tariff without harming non-
9 participating customers. The Company’s analysis has confirmed the conclusions reached
10 in other jurisdictions that monthly netting does not comport with sound cost-of-service rate
11 principles and, therefore, can result in costly cross-subsidies as the deployment of BTM
12 solar resources expand on the Company’s system. The Company supports customers’
13 choices regarding BTM solar, provided that equitable rate design and compensation
14 structures ensure the costs associated with operating the Company’s electric system
15 continue to be fairly recovered from its customers based upon appropriate cost causation
16 principles.

17 PIA Staff and Intervenor recommendations to implement an alternative compensation
18 mechanism, or minimum bill, or to expand the monthly netting pilot, focus solely on
19 maximizing the benefits to BTM solar participants and increasing BTM solar adoption.
20 The Company does not believe that increased BTM solar penetration alone, without
21 addressing the negative impacts to non-participating customers, is an appropriate measure
22 of success. Adopting these approaches would undermine Georgia’s measured approach
23 towards incentivizing the development of renewable energy resources, disproportionately
24 shift costs to non-participating customers, and excessively compensate BTM solar
25 resources at the expense of other customers on the system.

26 **II. STAFF AND INTERVENOR ARGUMENTS**

27 **Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE ANALYSIS AND**
28 **RECOMMENDATIONS PROVIDED BY PIA STAFF AND INTERVENOR**
29 **WITNESSES?**

1 A. No party credibly rebuts the Company’s analysis that a significant cost shift occurs under
2 the RNR tariff. PIA Staff and Intervenors go to great lengths to disregard the cost shift as
3 *de minimis*, re-characterize the shift as “revenue erosion,” dismiss the shift as affecting
4 only shareholders, highlight formulaic errors, or suggest that certain unrecognized benefits
5 outweigh the cost shift identified in the Company’s analysis. Nevertheless, the fundamental
6 principles contained in the Company’s analysis stand—that monthly netting, which
7 compensates customers for intermittent energy they deliver to the grid at the full volumetric
8 portion of the retail rate, allows these customers to shift the costs to build, operate, and
9 maintain the electric system onto non-participating customers. Second, as Dr. Gattie
10 testified, because of these flaws with monthly netting, several other state jurisdictions have
11 recently taken steps to modify monthly netting policy in favor of better cost alignment and
12 recovery. Again, intervenors may argue that monthly netting remains the predominant
13 practice nationwide, or that these policy reversals occurred only after sufficient penetration
14 in the market when the impact on rate structures became unsustainable, but the underlying
15 trend of shifting away from monthly netting at the full retail rate as the preferred policy
16 option in other state jurisdictions appears unopposed. Finally, there can be no doubt that
17 RNR customers will continue to rely upon and be served by the Company’s electric system,
18 and PIA Staff and Intervenors rightly do not challenge this unavoidable fact. They simply
19 provide reasons for why they believe BTM resources should not be required to pay for their
20 continued use of and reliance on the system, notwithstanding the cost shift to non-
21 participating customers.

22 **Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF PIA STAFF**
23 **ARGUMENTS REGARDING EXTENDING THE MONTHLY NETTING PILOT.**

24 A. PIA Staff does not advocate for an expansion of the monthly netting pilot. Instead, to our
25 understanding, PIA Staff seems to propose that future RNR customers be compensated
26 using one of several alternative pricing methodologies. We note that the prices proposed
27 by PIA Staff for excess energy range from 6.99¢ per kWh to almost 13¢, the extreme
28 variability of which suggests arbitrariness.

1 PIA Staff’s analysis began with a simple comparison of revenue generated from RNR
2 customers compared to the average R customer. From this they determined that RNR
3 customers “provide a substantial level of revenue to the Company.” The level of revenue
4 collected from customers provided in isolation does not determine the cost shift or avoided
5 costs from RNR customers. PIA Staff inaccurately claims that “within the ratemaking
6 calculus, we do not distinguish between ... any other criteria that affects individual costs.”
7 This is not true. A primary goal of rate design is to reflect the underlying cost-of-service.
8 PIA Staff is correct that “the cost to provide service varies for every single customer,”
9 which is why rates are designed to reflect a population of customers on a particular rate.
10 However, it is incorrect to assume that because one cannot account for every individual
11 nuance of customer usage characteristics and circumstances between customers that the
12 Company should not develop cost-based rates. Further, when considering a policy decision
13 that might promote a certain technology or usage characteristic, it is the Company’s
14 responsibility to inform the Commission of the cost shift and disproportionate impact to
15 non-participants.

16 PIA Staff then offers possible alternatives to the value of excess generation exported to the
17 grid. PIA Staff conveniently ignores the framework to value excess generation from BTM
18 solar systems that has been in place since 2017 and was recently reviewed and reaffirmed
19 in both the Company’s Avoided Cost Methodology Review in Docket Nos. 4822, 16573,
20 and 19279 and the 2022 IRP in Docket No. 44160. PIA Staff’s analysis assumes and
21 provides value for components neither approved nor recognized in the Company’s
22 Renewable Cost Benefit (“RCB”) Framework as applied to BTM solar systems.

23 The comparison of the value of a BTM system to Company-owned solar facilities is fraught
24 with issues. Georgia Power’s solar facilities were constructed such that the costs were
25 projected to be below avoided cost over the life of the project to benefit customers. This is
26 consistent with how the RCB Framework compensates RNR customers today – based on
27 the Company’s Solar Avoided Energy Costs. To pay RNR customers according to the RCB
28 Framework and then add a differential based on a certain point in time of a 30-year project,
29 would artificially inflate the benefits.

1 PIA Staff's second analysis is even more troubling. Table 3 of PIA Staff's testimony shows
2 that 1,473 bills had zero or negative billed kilowatt hours ("kWh") under RNR monthly
3 netting. Because these customers were billed for zero kWh usage, these customers did not
4 pay any of the volumetric charges under the R rate, which was designed to recover all of
5 the Company's generation, transmission, and most of the distribution costs for the
6 infrastructure that delivered energy to their home. By not paying any volumetric charges
7 in those months, these customers are shifting that entire cost to non-participants. PIA
8 Staff's second analysis contends that RNR customers should not only avoid volumetric
9 charges when they are not generating, but also be paid as if they provided actual
10 transmission and generation capacity to other customers. This stacking of subsidies does
11 not recognize actual avoided costs – only the Commission-approved RCB Framework does
12 that.

13 **Q. DOES PIA STAFF'S ANALYSIS ALTER THE COMPANY'S**
14 **RECOMMENDATIONS REGARDING THE USE OF THREE-PART RATES FOR**
15 **RNR CUSTOMERS?**

16 A. No. The Company continues to recommend that the Commission require all customers who
17 enroll in the RNR tariff on or after January 1, 2023 take service under a three-part rate,
18 such as the Company's TOU-RD or Smart Usage rate or an equivalent Commercial or
19 Industrial rate. Such rates provide more accurate price signals, are better aligned with our
20 cost to serve, and mitigate the majority of the underlying cost shift revealed in the
21 Company's analysis. Continuing to compensate BTM solar customers who take service on
22 a volumetric rate, whether via monthly netting or instantaneous netting, creates cost shifts
23 to non-participating customers that will continue to expand over time as more and more
24 BTM solar resources interconnect to the system.

25 **Q. HOW DO YOU RESPOND TO THE RECOMMENDATIONS FROM MANY**
26 **INTERVENORS THAT THE COMMISSION SHOULD LIFT THE CAP FOR**
27 **MONTHLY NETTING?**

28 A. Lifting the cap for monthly netting would severely harm non-participating customers by
29 expanding the disproportionate cost shift associated with monthly netting. As described in

1 the Supplemental Testimony of Dr. Gattie, similar to the experiences in California and
2 other jurisdictions, the cost shift grows as penetration levels increase, leading to the need
3 for regulatory or legislative revisions to better balance the interests of BTM solar
4 developers and customers. The Company recommends the Commission take advantage of
5 these lessons learned in other jurisdictions now to avoid the inevitable pitfalls of over
6 subsidizing BTM resources.

7 **Q. HAVE PIA STAFF OR THE INTERVENORS CREDIBLY CONTRADICTED THE**
8 **EXISTENCE OF A COST SHIFT RESULTING FROM MONTHLY NETTING?**

9 No. PIA Staff and Intervenors have argued that the cost shift is small, outweighed by
10 supposed benefits, or should be accepted as a means of achieving broader policy goals, but
11 they have not disproven the Company's demonstration that a cost shift occurs when
12 analyzing all appropriate costs and benefits. PIA Staff's compensation proposals and
13 various Intervenors' minimum bill proposals tacitly acknowledge this fact, in that they seek
14 to mitigate some, but not all, of the cost shift inherent in the RNR tariff's current rate
15 design. The primary fault with monthly netting as an accounting construct is that it enables
16 a customer to zero or net out its usage during the billing period despite the fact that the
17 customer actually relied upon and was served by the system during that same billing period.
18 A customer that consumes electricity from Georgia Power's system should bear
19 responsibility for the cost of such usage. But monthly netting allows an RNR customer that
20 consumes electricity from the Company to still avoid all volumetric charges associated
21 with a monthly bill, and a primarily volumetric-based rate such as the R rate magnifies this
22 problem. Fundamental cost-based rate design principles obligate the Company to address
23 this problem. This problem is also why, as Dr. Gattie testified, many states have modified
24 their monthly netting policies and adopted alternative approaches to compensate BTM
25 resources to address this fundamental problem posed by monthly netting.

26 **Q. HOW DO YOU RESPOND TO THE CHARACTERIZATIONS THAT GEORGIA**
27 **POWER'S STUDY DOES NOT SHOW A COST SHIFT TO RESIDENTIAL**
28 **CUSTOMERS BUT RATHER A SHIFT TO COMPANY SHAREHOLDERS?**

1 A. This characterization is inaccurate. While “revenue erosion” could result in less revenue
2 being collected in the immediate short term, rates will ultimately be set to recover these
3 costs. As the Company recovers less revenue from RNR customers, non-RNR customers
4 will increasingly bear the burden of recovering those costs.

5 Intervenor acknowledge that some other party must assume an RNR customer’s share of
6 fixed costs to support the system that RNR customers will continue to rely upon. We find
7 it curious that these Intervenor seem fine with, under their own characterization, having a
8 rate design that deliberately under-recovers the very revenue requirement set in this case.
9 The Commission should reject such short-term thinking. Should monthly netting continue,
10 every time the Company updates its forecasts and redesigns prices within the rate case
11 process, more costs will be shifted to non-participating customers.

12 **Q. PLEASE RESPOND TO THE CLAIMS OF ADDITIONAL BENEFITS OF BTM**
13 **GENERATION ASSERTED BY PIA STAFF AND INTERVENORS.**

14 A. Many Intervenor suggest that the Commission expand monthly netting for policy reasons
15 that go far beyond the scope of a traditional cost-of-service rate case, such as concerns
16 related to enhancing employment, environmental justice, or climate impacts. These
17 considerations are not components of avoided cost and should not be included in
18 compensation to BTM customers.

19 With respect to transmission, distribution and other system benefits, all appropriate benefits
20 have been included in the Company’s analysis. Both PIA Staff and Intervenor fail to
21 acknowledge that the Commission already considers the myriad of benefits for solar
22 resources within the Company’s RCB Framework. To the extent these benefits exist, the
23 Commission has already identified and quantified these benefits. RNR customers receive
24 compensation for these benefits through the Company’s Solar Avoided Energy Cost Rate
25 currently paid to instantaneous netting customers for excess energy pushed back onto the
26 grid.

1 **Q. DO YOU AGREE WITH PIA STAFF'S AND INTERVENORS' ARGUMENTS**
2 **REGARDING CAPACITY BENEFITS?**

3 A. No. Consistent with the Commission's determination in the Avoided Cost Methodology
4 proceedings and reaffirmed in the recent IRP ruling, generation, transmission, and
5 distribution capacity benefits should not be included in compensation paid to RNR
6 customers. According to PIA Staff and Intervenor, because excess energy produced by
7 the customer-generator is likely to remain within the Company's distribution system, this
8 excess energy does not rely on the Company's transmission system. In GSEIA's analysis
9 for example, GSEIA analyzes and ascribes value to both "inflow" and "outflow" energy to
10 conclude that BTM solar systems provide more system benefits than the amount of
11 unrecovered revenue avoided by RNR customers. This analysis assumes the Company can
12 realize these benefits by downsizing transmission and distribution system investments in
13 amounts commensurate with GSEIA's analysis. The only true result of GSEIA's analysis
14 is that it confirms that current costs are shifted to non-participating customers through
15 GSEIA's proposed reallocation. PIA Staff and Intervenor focus solely on the excess
16 energy produced by the customer, and do not acknowledge the integrated nature of the
17 transmission and distribution infrastructure that is required to serve the same RNR
18 customer at times when the customer's BTM solar system is not generating or is not fully
19 meeting the RNR customer's energy needs.

20 It is also inappropriate to include generation capacity benefits in compensation to RNR
21 customers. This issue has been litigated before and affirmed by this Commission several
22 times. The Company cannot plan for or rely upon BTM resources to ensure system
23 reliability because the customer is under no contractual obligation to generate, and even if
24 they happen to be generating and delivering excess energy to the system, their energy is
25 not required to be available in the future and thus is not included in generation capacity
26 planning. The Company has an obligation to reliably serve customers, which requires
27 planning for firm, reliable resources available to meet peak demand. BTM systems do not
28 meet those requirements and, therefore, do not provide generation capacity avoidance
29 value. Thus, BTM resources—although providing an alternative source of energy—do not
30 provide any capacity-related benefits to the system.

1 **Q. ARE INTERVENORS' MINIMUM BILL PROPOSALS SUFFICIENT TO**
2 **ADDRESS THE COST SHIFT?**

3 A. No. The minimum bill proposals by Intervenor are not sufficient to address the cost shift.
4 In recommending a minimum bill, Intervenor implicitly acknowledge that some amount
5 of non-volumetric fixed charges are appropriate to ensure RNR customers pay their fair
6 share of costs. However, the minimum bills proposed are essentially only equal to the
7 Company's customer-related costs for residential customers that is determined in the Cost
8 of Service Study ("COSS"). As previously established, RNR customers continue to rely
9 upon Georgia Power's system to serve their electric service needs and to receive any excess
10 energy the customer produces. As a result, setting a minimum bill that only captures the
11 customer-related portion of costs would continue to enable RNR customers to utilize the
12 electric infrastructure at a reduced price and shift these demand-related costs to non-
13 participants.

14 **III. THE COMPANY'S ANALYSIS**

15 **Q. HOW DO YOU RESPOND TO THE CRITICISMS BY PIA STAFF THAT THE**
16 **COMPANY DID NOT PROVIDE SUFFICIENT COST INFORMATION TO**
17 **SUPPORT ITS RECOMMENDATIONS AND INTERVENOR COMPLAINTS**
18 **THAT THE COMPANY'S ANALYSIS IS NOT COST-BASED?**

19 A. First, the Company presented its analysis within the context of its overall base rate case,
20 which includes a holistic look at all the Company's costs as supported by a comprehensive
21 COSS. As such, all the Company's cost information is available and transparent.
22 Additionally, the Company provided comprehensive cost data in response to data requests
23 based on our Supplemental Direct Testimony. The analysis provided a standard,
24 comprehensive non-fuel cost-benefit analysis for RNR customers and non-participants.
25 The Company only included non-fuel costs and benefits in its analysis as part of this base
26 rate case but there are additional fuel benefits and savings from RNR customers reflected
27 in the Fuel Cost Recovery Docket. The results in Figure 3 of our Supplemental Direct
28 Testimony show non-fuel cost shifts resulting from the R tariff and RNR monthly netting.
29 The data also shows the non-fuel Avoided Energy Savings/Benefits generated by these

1 customers are derived from the Company's filed COSS in this case and is consistent with
2 the Commission's determination of Solar Avoided Energy Costs in the Avoided Cost
3 Methodology proceedings and reaffirmed in the Company's 2022 IRP. Unlike PIA Staff
4 and Intervenor analyses, the Company's cost analysis does not presume benefits and results
5 that contradict the Commission's previous decisions on this matter. The Company's
6 analysis uses the available data specific to RNR customers to demonstrate the cost shift
7 caused by the RNR rate structure in order to provide the Commission with the necessary
8 information to inform its decision-making.

9 **Q. IS A SEPARATE COSS NECESSARY FOR THE COMMISSION TO EVALUATE**
10 **THE MONTHLY NETTING PILOT?**

11 A. No. A COSS, such as the one GSEIA references, would only validate the cost shift and
12 show what rates/rate groups the costs were shifted onto. This 'after the fact' analysis does
13 not show avoided costs, just a reallocation of costs already incurred. Additionally, GSEIA
14 ignores that treatment of capacity benefits has repeatedly been litigated and reaffirmed in
15 Commission proceedings. The appropriate analysis is shown in our Supplemental Direct
16 Testimony and demonstrates a disproportionate cost shift to non-participants today.

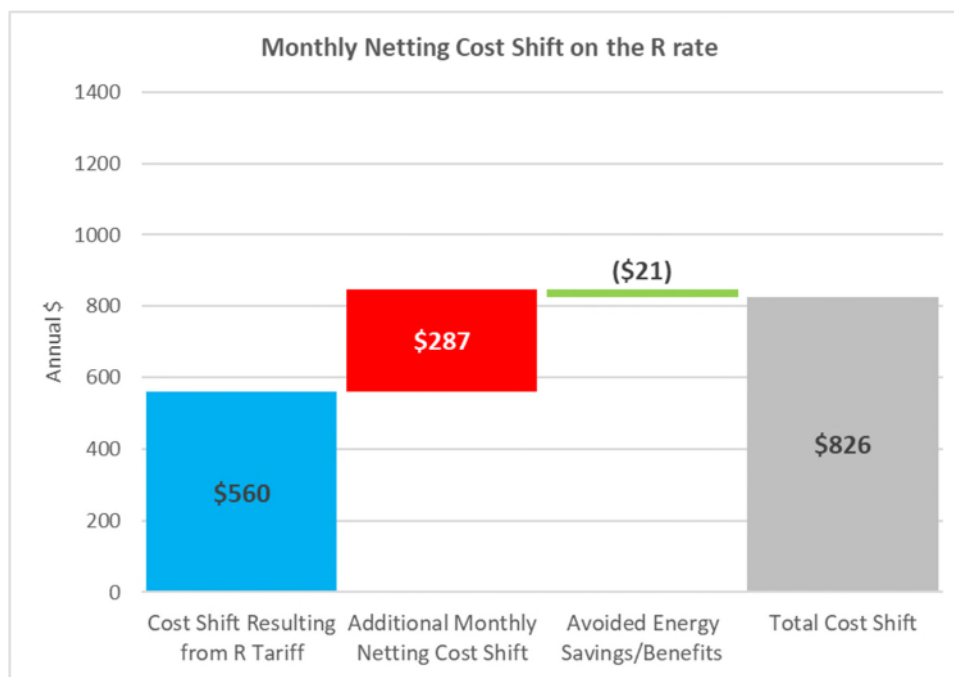
17 **Q. PLEASE EXPLAIN THE COMPANY'S ACTIONS FOLLOWING THE**
18 **IDENTIFICATION OF AN INADVERTENT ERROR IN ITS CALCULATIONS**
19 **OF THE COST SHIFT ANALYSIS INCLUDED IN YOUR SUPPLEMENTAL**
20 **DIRECT TESTIMONY.**

21 A. The Company has confirmed an error in the calculation of the cost shift associated with the
22 monthly netting pilot that was identified in the testimonies intervening parties filed on
23 November 18, 2022. This formulaic error resulted in an incorrect overstatement of the cost
24 shift in the Company's Supplemental Direct Testimony. The Company has corrected this
25 mistake and further conducted a thorough review of all calculations within the cost shift
26 analysis, which resulted in two additional minor corrections to the cost shift results. The
27 Company filed this information with the Commission on November 21, 2022 as an errata.

1 **Q. DID THE CORRECTION TO THE STUDY CHANGE THE COMPANY’S**
2 **RECOMMENDATION?**

3 A. No. Although the updates had the net effect of reducing the results of the cost shift analysis
4 for participants on the R rate, the cost shift remains a significant burden that is transferred
5 to all other customers. In total, the annual cost shift included in the Supplemental Direct
6 Testimony is recalculated from \$1,356 to \$826 for the average monthly netting participant
7 on the R tariff. The vast majority of the change is captured in the recalculation of the cost
8 shift resulting from the R tariff for the energy consumed behind the meter; however, there
9 were small changes captured in the calculation of the monthly netting cost shift as well.
10 Notwithstanding these updates, the cost shift analysis continues to support our
11 Supplemental Direct Testimony and our recommendations remain the same. Figure 1
12 below demonstrates this cost shift using the corrected analysis.

13 **Figure 1**



1 IV. RNR RATE STRUCTURE

2 Q. HOW DO YOU RESPOND TO THE RECOMMENDATIONS BY PIA STAFF AND
3 INTERVENORS THAT THE R RATE SHOULD REMAIN THE DEFAULT RATE
4 FOR RNR CUSTOMERS?

5 A. We disagree. As we stated in our Supplemental Direct Testimony, the Company is
6 proposing to move existing RNR customers onto the TOU-RD tariff to achieve two
7 objectives: (1) to mitigate the cost shift identified in the Company's analysis; and (2) to
8 ensure our rates most accurately reflect the cost-of-service and cost-causation principles.
9 The level of cost shift under the R rate is higher because the R rate does not appropriately
10 match the collection of revenues with how the Company incurs its costs. By continuing
11 with the R rate, this cost shift will only intensify as the number of RNR customers
12 increases.

13 Q. WHAT ARE PIA STAFF AND INTERVENOR OBJECTIONS TO THE TOU-RD
14 RATE?

15 A. As we understand it, PIA Staff and Intervenor objections do not appear to be motivated by
16 rate design principles, but rather with concerns regarding the reduced level of payment
17 some RNR customers would receive under TOU-RD. Intervenor appears to favor the R
18 rate because this rate maximizes the level of incentives provided to the BTM solar market,
19 without regard to the consequences for non-participating customers or cost-causation
20 principles. Intervenor has failed to demonstrate that the TOU-RD tariff does not
21 appropriately recover costs reasonably and fairly. Instead, these arguments appear reactive
22 to the potential for the TOU-RD rate to mitigate the current subsidy available under the R
23 tariff and reduce RNR customers' savings opportunities.

24 V. OTHER ISSUES

25 Q. DOES THE COMPANY AGREE WITH GSEIA'S RECOMMENDATION THAT
26 THE COMMISSION SHOULD CONSIDER BILL AMOUNTS RATHER THAN
27 RATES?

1 A. No. The Commission should consider the Company's rates, rather than electric bills, as the
2 appropriate metric. First, the Commission has jurisdiction over the rates the Company
3 charges, not how much electricity Georgia Power's customers use. Second, a customer
4 with high usage but a low rate can pay a higher electric bill than a customer with a higher
5 rate but lower usage. Finally, Georgia's measured approach to renewable energy policy has
6 helped keep Georgia's electric rates lower than many states with higher levels of rooftop
7 solar penetration.

8 **VI. CONCLUSION**

9 **Q. IN LIGHT OF ALL OF THE ABOVE, WHAT SHOULD THIS COMMISSION DO**
10 **TO MITIGATE THE COST SHIFT THAT OCCURS WITH MONTHLY NETTING**
11 **AND INSTANTANEOUS NETTING?**

12 A. The monthly netting pilot causes a disproportionate cost shift to non-participating
13 customers. As such, it should remain capped at 5,000 customers. Additionally, given the
14 cost shift that is also inherent in the Company's instantaneous netting program, the
15 Company recommends that the Commission require all customers who enroll in the RNR
16 tariff on or after January 1, 2023, to take service under a three-part rate, such as the
17 Company's TOU-RD rate, to mitigate the disproportionate cost shift to non-participating
18 customers. These recommendations appropriately balance the need to protect non-
19 participating customers while continuing to support the growth of BTM resources.

20 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

21 A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the within and foregoing SUPPLEMENTAL REBUTTAL TESTIMONY OF THE PANEL OF LEE EVANS AND LARRY LEGG ON BEHALF OF GEORGIA POWER COMPANY IN DOCKET NO. 44280 upon all parties listed below via electronic service or by hand delivery and addressed as follows:

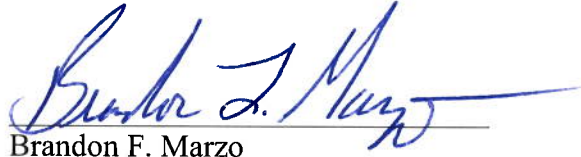
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This 23rd day of November 2022.



Brandon F. Marzo

Attorney for Georgia Power Company

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1 MR. HEWITSON: Madam Chair, with your
2 permission, I'd like to ask Mr. Legg to summarize the
3 panel's testimony.

4 MADAM CHAIR PRIDEMORE: Please go ahead,
5 Mr. Legg.

6 MR. LEGG: Good afternoon, Madam Chair and
7 Commissioners. Mr. Evans and I thank you again for
8 the opportunity to be here today.

9 We're here today to respond to recommendations
10 made by PIA Staff and the intervenors as they relate
11 to the company's monthly netting pilot and the
12 appropriate structure and pricing of the renewable
13 and nonrenewable or RNR tariff.

14 There were a lot of recommendation made and we
15 addressed many of them in our testimony, but not all.
16 The fact that we may not specifically address
17 particular recommendations made by staff or an
18 intervenor should not be construed as support for
19 such position.

20 Our testimony reaffirms the company's
21 recommendation that the Commission not expand the RNR
22 monthly netting pilot and require all future RNR
23 customers to take service under a three-part rate,
24 such as the company's TOU-RD rate.

25 The monthly netting pilot has served its

1 limited purpose in providing a data set for the
2 company and Commission to consider whether monthly
3 netting provides a reasonable balance between
4 incentivizing customer-owned behind-the-meter solar
5 on the RNR tariff without harming nonparticipating
6 customers. The company's analysis, which is
7 supported by its cost of service study and
8 comprehensive data supplied in this rate case, and
9 with our supplemental direct testimony and data
10 request responses has confirmed the conclusions
11 reached in other jurisdictions that monthly netting
12 does not comport with sound cost of service rate
13 principles and, therefore, can result in costly
14 cross-subsidies as the deployment of behind-the-meter
15 solar resources expand on the company's system.

16 The company supports customers' choices
17 regarding behind-the-meter solar, provided that
18 equitable rate design and compensation structures
19 ensure the costs associated with operating the
20 company's electric system continue to be fairly
21 recovered from its customers based upon appropriate
22 cost causation principles.

23 No party credibly rebuts the company's analysis
24 that a significant cost shift occurs under the RNR
25 tariff in the monthly netting pilot. PIA Staff and

1 intervenors go to great lengths to disregard the cost
2 shift as de minimus, to recharacterize the cost shift
3 as revenue erosion, to dismiss the cost shift as
4 affecting only shareholders, or to suggest that
5 certain unrecognized benefits outweigh the cost shift
6 identified in the company's analysis.

7 Nevertheless, the fundamental principles
8 contained in the company's analysis stand that
9 monthly netting, which compensates customers for
10 intermittent energy they deliver to the grid at the
11 full volumetric portion of the retail rate, allows
12 these customers to shift the cost to build, operate,
13 and maintain the electric system onto
14 nonparticipating customers.

15 Intervenorors have argued that monthly netting
16 remains the predominant practice nationwide, or that
17 net metering policy reversals occur only after
18 sufficient penetration in the market when the impact
19 on rate structures became unsustainable. However,
20 the fact remains that numerous states have recently
21 taken steps to modify their net metering policies,
22 transitioning away from monthly netting at the full
23 retail rate in favor of better cost alignment and
24 cost recovery. These actions were taken to correct
25 the cost shift problem those states were experiencing

1 with monthly netting, which is the very same issue we
2 are seeking to address here in Georgia.

3 Moreover, staff and intervenors failed to
4 acknowledge the Commission-approved renewable cost
5 benefit framework, which appropriately values the
6 excess generation from behind-the-meter solar
7 resources. The RCB framework, which has been in
8 place since 2017, was recently reviewed and
9 reaffirmed in both the company's avoided cost
10 methodology review in 2021 and the 2022 IRP.

11 There is no doubt that RNR customers will
12 continue to rely upon and be served by the company's
13 electric system. PIA Staff and intervenors rightly
14 do not challenge this fact. Instead, they simply
15 argue why they believe RNR customers should not be
16 required to pay for their continued use of and
17 resilience on -- and reliance on the electric system,
18 notwithstanding the cost shift to nonparticipating
19 customers.

20 Notably, PIA Staff and intervenor
21 recommendations to implement an alternative
22 compensation mechanism or minimum bill tacitly
23 acknowledge the existence of the cost shift. Their
24 proposals to seek to mitigate some, but not all, of
25 the cost shift inherent in the RNR tariff's current

1 rate design. Staff and intervenor proposals focus
2 solely on maximizing the benefits to behind-the-meter
3 solar participants and increasing behind-the-meter
4 solar adoption.

5 While the company supports the choices of its
6 customers with respect to the development of
7 behind-the-meter solar, we do not believe that
8 increased behind-the-meter solar penetration alone
9 without addressing the negative impacts to
10 nonparticipating customers is an appropriate measure
11 of success. Adopting these approaches would
12 undermine Georgia's measured approach towards
13 incentivizing the development of renewable energy
14 resources, disproportionately shift cost to
15 nonparticipating customers, and excessively
16 compensate behind-the-meter solar resources at the
17 expense of other customers on the system.

18 In summary, the monthly netting pilot causes a
19 disproportionate cost shift to nonparticipating
20 customers. As such, it should remain capped at 5,000
21 customers.

22 Additionally, given the cost shift that is also
23 inherent in the company's instantaneous netting
24 program, the company recommends that the Commission
25 require all customers who enroll in the RNR tariff on

1 or after January 1st, 2023, to take service under a
2 three-part rate, such as the company's TOU-RD rate,
3 to mitigate the disproportionate cost shift to
4 nonparticipating customers. These recommendations
5 appropriately balance the need to protect
6 nonparticipating customers while continuing to
7 support the growth of behind-the-meter resources.

8 The Commission should adopt the company's
9 proposal, which will help ensure that going forward
10 the disproportionate cost shift between customers
11 with behind-the-meter generation and nonparticipating
12 customers is minimized to the greatest extent
13 possible.

14 Thank you for your time and consideration.

15 MR. HEWITSON: Witnesses are now available for
16 questions from the Commission, as well as
17 cross-examination.

18 COMMISSONER MCDONALD: Questions from the
19 Commissioners?

20 MR. HEWITSON: Yes.

21 COMMISSONER MCDONALD: Commissioner Echols.

22 VICE-CHAIRMAN ECHOLS: Mr. Legg, you heard
23 maybe Dr. Brown mention about the shift of the peak
24 and the costly nature of it when you hit about
25 10 percent.

1 Did you hear that?

2 MR. LEGG: Yes.

3 VICE-CHAIRMAN ECHOLS: So do you -- do you
4 agree that that 10 percent number, that when you
5 start shifting that peak later that it is more
6 damaging to the system compared to, say, what we have
7 now?

8 MR. LEGG: I haven't studied that specifically,
9 Commissioner Echols. That is something I know that
10 our generation planning folks look at intently is
11 when the system peaks and anything that impacts that
12 peak. I know that -- the impacts in other states
13 that have seen that.

14 Certainly that's something that we keep in mind
15 when planning our system and thinking about things
16 out into the future, but I haven't studied it
17 specifically in pricing.

18 VICE-CHAIRMAN ECHOLS: One more, if I could,
19 Commissioner McDonald.

20 The slow and steady modest idea of just adding
21 a few more -- maybe not 75,000, whatever the number
22 the Commission would be comfortable with, to keep
23 Wilson's department, you know, running, we've spent
24 considerable money standing that department up.
25 Probably more than the cost shift. But we've got

1 that department stood up.

2 Is there -- is there real harm in us keeping it
3 going and letting our citizens pull down this tax
4 money?

5 Because we know -- we know that the policy --
6 this net metering policy triggers. It triggers, you
7 know, a wild west type of -- you know, everybody
8 wanting to do it. So is there real harm with us --
9 with us doing that and capping a smaller amount?

10 MR. LEGG: Yeah. I think -- I think the
11 concern of the company, Commissioner, is even if we
12 move forward with an additional small number of
13 customers, it doesn't change the fact that the cost
14 shift is going to occur. It doesn't really change
15 the fact that you now have customers who are
16 subsidizing their neighbor whose -- who decided to
17 put solar panels on their roof and they're paying
18 more on their electricity bill to allow those
19 customers to have monthly netting.

20 I think that's the concern of the company.
21 It's a matter of fairness in the cost shift and who
22 pays for what. And so from that standpoint, that is
23 what the company's concern is.

24 And I would say the additional concern is,
25 moving forward with a -- continuing with a small

1 number going forward, I'm not aware of anywhere where
2 you would continue to move forward, but eventually
3 that small number doesn't become a big number. We've
4 heard some testimony and some discussion here today
5 earlier at what point do you say: Okay. That's
6 enough.

7 And then everybody who's gotten this benefit of
8 having, you know, in many months no bill at all
9 because they've netted out all of their kilowatt-hour
10 usage and then you start saying to other customers --
11 either those existing customers: You can't have that
12 anymore. Or other customers: You can't get that
13 from here on out.

14 I'm just not sure where that stops. And that's
15 the concern is that it becomes a large number over
16 time, as we've seen in many other states.

17 VICE-CHAIRMAN ECHOLS: Why wasn't there
18 substantial objection to my motion in '19 from the
19 company and telling us right then and there that we
20 shouldn't move forward and, no, we're not going agree
21 to this?

22 Why didn't -- did you all not, you know, go to
23 the mat in '19 when I did the motion?

24 MR. LEGG: I can't speak to that, Commissioner.
25 I wasn't actually here in the room when that

1 happened, but -- so I can't speak to that.

2 VICE-CHAIRMAN ECHOLS: Thank you so much.

3 COMMISSONER MCDONALD: What's small, Mr. Legg?

4 MR. LEGG: I'm sorry?

5 COMMISSONER MCDONALD: What's small?

6 MR. LEGG: When you say small --

7 COMMISSONER MCDONALD: You said small.

8 MR. LEGG: Right. I was answering -- I was

9 responding to Commissioner Echols. He was just

10 saying a small number. I didn't have a particular

11 number in mind.

12 I would say we've heard numbers here --

13 COMMISSONER MCDONALD: Seventy-five? Eighty?

14 Fifty?

15 MR. LEGG: I would consider those large --

16 large increases in the number. You -- 50,000 would

17 be ten times as many customers as we have now.

18 There's been a lot of discussion about the cost

19 shift and customers continuing to use the

20 \$1.4 million number. When you include the

21 behind-the-meter piece of that, the instantaneous

22 cost shift, it's actually more like 4 million, 4 and

23 a half million dollars for the 5,000 customers.

24 So if you -- if you went to 50,000 from 5,000,

25 just doing simple math, that would be about

1 \$40 million a year in cost shift.

2 There have actually been parties here who have
3 suggested 100,000. One I think was 295,000. You're
4 talking about hundreds of millions of dollars in cost
5 shift per year at that point.

6 So I guess small is in the eye of the beholder,
7 but I would consider any of those numbers of -- that
8 you gave a large -- a large increase.

9 MADAM CHAIR PRIDEMORE: Anything else from
10 Commissioners?

11 (No response.)

12 MADAM CHAIR PRIDEMORE: Okay. Cross.

13 Georgia Public Service Commission.

14 Oh, you have something. Good.

15 MR. WALSH: Yeah, we have some questions.

16 MADAM CHAIR PRIDEMORE: Oh, it's good to see
17 you again. Glad you're feeling better.

18 MR. INGRAHAM: Thank you, Madam Chair. I'm
19 glad to be feeling better and glad to be back at
20 these proceedings.

21 CROSS-EXAMINATION

22 BY MR. INGRAHAM:

23 Q Good afternoon, panel, Mr. Evans, Mr. Legg.

24 Mr. Legg, the company, staff, all the
25 intervenors, all the parties to this case have taken a

1 variety of positions on this issue, but would you agree that
2 the task of striking an appropriate balance on this issue is
3 ultimately a policy decision for the Commission?

4 A (Witness Legg) Yes. Absolutely. And we've
5 stated it as such.

6 MR. INGRAHAM: Okay. Thank you.

7 No more questions.

8 MADAM CHAIR PRIDEMORE: Americans for
9 Affordable Clean Energy.

10 MR. GALLOWAY: No questions, Madam Chair.

11 MADAM CHAIR PRIDEMORE: ChargePoint.

12 MR. FYKES: No questions.

13 MADAM CHAIR PRIDEMORE: Georgia Coalition of
14 Local Governments.

15 MS. BROWN: No questions.

16 MADAM CHAIR PRIDEMORE: GIPL.

17 MS. WHITFIELD: No questions.

18 MADAM CHAIR PRIDEMORE: GA Solar.

19 MR. MORELAND: No questions.

20 MADAM CHAIR PRIDEMORE: GASEIA.

21 MR. THOMASSON: No questions.

22 MADAM CHAIR PRIDEMORE: MARTA.

23 MS. STURM: No questions.

24 MADAM CHAIR PRIDEMORE: Sierra Club.

25 MS. ARIZA: No questions.

1 MADAM CHAIR PRIDEMORE: SACE and Southface.

2 MR. DOWDY: No questions.

3 MADAM CHAIR PRIDEMORE: Redirect.

4 MR. HEWITSON: I have no redirect, Madam Chair.

5 May the -- may we enter Exhibits 44 and 45 into

6 the record and may the witnesses finally be excused.

7 MADAM CHAIR PRIDEMORE: So moved. You're

8 finally excused.

9 (GPC Exhibit 44 was admitted into evidence.)

10 (Witness excused.)

11 MADAM CHAIR PRIDEMORE: All right. Any other

12 housekeeping matters to come before us?

13 VICE-CHAIRMAN ECHOLS: I just have a question,

14 Madam Chair. If you could clarify the ex parte rule

15 and how that would work.

16 MADAM CHAIR PRIDEMORE: That would be a

17 housekeeping matter. I'm sorry. You were saying --

18 I will.

19 MR. HEWITSON: I was just going to say, to the

20 extent that we haven't moved all our exhibits into

21 the record, may we please do that now?

22 MADAM CHAIR PRIDEMORE: Yes.

23 MR. HEWITSON: Thank you.

24 MADAM CHAIR PRIDEMORE: Georgia Power may do

25 that.

1 Does Georgia Public Service Commission need to
2 do that?

3 MR. THOMAS: I'm sorry. I didn't hear the
4 question.

5 MADAM CHAIR PRIDEMORE: I'm so glad you're with
6 us today, Mr. Thomas.

7 Do you have any exhibits you want to move into
8 the record?

9 MR. THOMAS: I believe we've moved all of ours
10 into the record.

11 MADAM CHAIR PRIDEMORE: You have.

12 MR. THOMAS: But to any extent that we haven't,
13 we would ask them to be.

14 MADAM CHAIR PRIDEMORE: Okay. So moved.

15 All right. Any other housekeeping matters?

16 (No response.)

17 MADAM CHAIR PRIDEMORE: Okay. Ex parte begins
18 at the conclusion of this hearing. It means if
19 you're a party, you cannot talk to Commissioners,
20 unless you talk to all the Commissioners in an email
21 in written format, that way all the party members get
22 to see.

23 I advise you, if you have questions about
24 ex parte, see Tom Bond, the utilities director of the
25 Commission.

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I am going to ask the court reporter at this
time to make all exhibits part of the record.

Thank you for time. This hearing is now
concluded.

(Whereupon, the proceedings concluded at
3:31 p.m.)

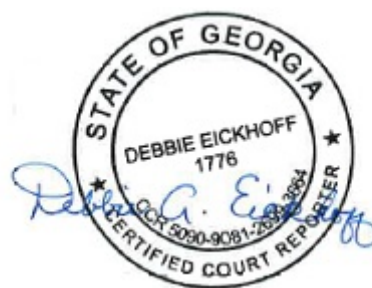
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C E R T I F I C A T E

We, Kelley Nadotti, Debbie Eickhoff and Brenda P. Elwell, Certified Court Reporters, do hereby certify that the foregoing transcript is an accurate record to the best of our abilities of the proceedings in the above-entitled matter at the time and place therein set forth.



Kelley Marie Nadotti, RPR
CCR-6256-8388-8026-4192



Debbie A. Eickhoff, RPR
CCR-5090-9084-2699-3664



Brenda P. Elwell, RPR, CRR, B-2023