STATE OF GEORGIA

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:)
)
Georgia Power Company's 2025) Docket No. 56002
Integrated Resource Plan)

-and-

Georgia Power Company's 2025) Docket No. 56003
2025 Application for the)
Certification, Decertification)
and Amended Demand-Side) *** Volume 3 of 3 ***
Management Plan)

Hearing in Room 110
244 Washington Street
Atlanta, Georgia

Thursday, March 27, 2025

The Session was called to order, pursuant to Notice at 9:30 a.m.

PRESENT WERE:

JASON SHAW, Chairman
TIM ECHOLS, Vice-Chairman
FITZ JOHNSON, Commissioner
LAUREN "BUBBA" MCDONALD, Commissioner
TRICIA PRIDEMORE, Commissioner

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I N D E X

EXHIBITS	FOR IDENTIFICATION	IN EVIDENCE
GPSC		
7 - STF-LA-1-19	1307	1328
GIPL/Southface		
8 - GPC Data Centers	1330	1337
9 - Southern Company Net Zero Q & A Supplement	1329	1337
NRDC/SACE/Sierra Club		
1 - STF-PIA-4-15	1351	1358

P R O C E E D I N G S

CHAIRMAN SHAW: Good morning, everyone. Thanks for joining us again today for the third day of these hearings. We're on the second witness panel still and we'll pick up where we left off.

First, I'll call for appearances. This is Docket No. 56002: Georgia Power Company's 2025 Integrated Resource Plan.

Calling for appearances starting with the Georgia Public Service Commission.

MR. PAWLUK: Good morning, Commissioners. Justin Pawluk for the PIA Staff.

CHAIRMAN SHAW: Good morning.

MR. PAWLUK: With me is my associate -- or my colleague, Attorney Chris Collado.

CHAIRMAN SHAW: Georgia Power Company.

MS. PRYOR: Good morning, Commissioners. Allyson Pryor, Brandon Marzo and Steve Hewitson for Georgia Power Company.

CHAIRMAN SHAW: Good morning.

Advanced Power Alliance.

(No response.)

CHAIRMAN SHAW: Advanced Power Alliance.

(No response.)

CHAIRMAN SHAW: Well, he was just here.

Americans for Affordable Clean Energy.

MR. PENLAND: Good morning. David Penland, Newton Galloway, Terry Lyndall on behalf of ACE.

CHAIRMAN SHAW: Clean Energy Buyers Association.

(No response.)

CHAIRMAN SHAW: Capital Good Fund.

MS. BROWN: Good morning, Mr. Chairman. Alicia Brown on behalf of Capital Good Fund.

CHAIRMAN SHAW: Fermata Energy.

(No response.)

CHAIRMAN SHAW: Georgia Association of Manufacturers.

MR. JONES: Clay Jones for GAM.

CHAIRMAN SHAW: Good morning.

Georgia Center for Energy Solutions.

(No response.)

CHAIRMAN SHAW: Georgia Center for Energy Solutions.

(No response.)

CHAIRMAN SHAW: Georgia Coalition for Local Governments.

MR. SMART: Good morning, Commissioners. Cordon Smart here on behalf of Georgia Coalition of Local Governments.

CHAIRMAN SHAW: Good morning.

Georgia Conservation Voters Education Fund.

MR. ESTRADA: Good morning. Juan Estrada for GCVEF.

CHAIRMAN SHAW: Good morning.

Georgia Interfaith Power & Light and Southface Energy Institute.

MR. SHERRIER: Good morning. Bob Sherrier and Jennifer Whitfield on behalf of GIPL and Southface.

CHAIRMAN SHAW: Georgia Solar Energy Industries Association.

MR. JONES: Chairman, Commissioners, Steven Jones and Matthew McKagen on behalf of the Georgia Solar Energy Industries Association.

CHAIRMAN SHAW: Georgia Solar Energy Association, Georgia Solar.

Mr. Moreland.

Georgia Watch.

Ms. Coyle, she'll get here later.

Georgia WAND Education Fund, Inc. and Vote Solar.

MS. KVIEN: Good morning, Commissioners. Alison Kvien on behalf of Vote Solar and Georgia WAND.

CHAIRMAN SHAW: Metropolitan Atlanta Rapid Transit Authority, MARTA.

(No response.)

CHAIRMAN SHAW: Microsoft.

(No response.)

CHAIRMAN SHAW: I reckon everybody had a late night. We're going to go late tonight.

Microsoft.

(No response.)

CHAIRMAN SHAW: Resource Supply Management.

(No response.)

Resource Supply Management.

(No response.)

CHAIRMAN SHAW: We may not be here late tonight if these people don't show up.

Sierra Club, Southern Alliance For Clean Energy and The Natural Resources Defense Council.

(No response.)

CHAIRMAN SHAW: Southern Renewable Energy Association.

MR. COX: Good morning, Commissioners. Whit Cox on behalf of the Southern Renewable Energy Association.

CHAIRMAN SHAW: Thank you.

United States Department of Defense and All

Other Federal Executive Agencies.

(No response.)

CHAIRMAN SHAW: Walmart.

MS. EATON: Good morning, Commissioners. Stephanie Eaton here on behalf of Walmart. Thank you.

CHAIRMAN SHAW: Good morning.

All right. I see you, Mr. Carver. We've got you. I knew you were here.

Okay. Moving on, we will -- we're going to call up and I have a sheet with our public witnesses. We've got a lot less today so we'll be able to get into the hearing a little quicker.

I guess the --

COMMISSONER McDONALD: Does that mean that's quality, less quantity?

CHAIRMAN SHAW: Yeah. This is just the quality. Best for last.

COMMISSONER McDONALD: Right.

CHAIRMAN SHAW: No. We've had a lot of good public comments this week. So we're going to move on.

I'll remind everyone that you've got three minutes each, but you're not going to get electrocuted or anything if you go past it. We appreciate you. Brevity is popular here.

All right. We're going to start with Mr. Adam Forrand, followed by Steve Stroud.

MR. FORRAND: Good morning, Chairman. Good morning, Commissioners.

My name is Adam Forrand. I'm the president and CEO of the Greater Perimeter Chamber representing businesses in Dunwoody, Sandy Springs, and the top end Perimeter region. I appreciate the opportunity to speak with you this morning about Georgia Power's Integrated Resource Plan and why it is essential to our region's economic future.

The Perimeter and Metro Atlanta continues to grow at an unprecedented pace, attracting companies that create thousands of new, high-quality jobs. But behind every successful business, there's a critical factor that is often overlooked or taken for granted. And that is reliable energy.

Our recent success is no accident. It is built on a strong business climate, a highly skilled and diverse workforce, and, critically, a power grid that supports such growth.

Companies depend on energy that is not just affordable, but also resilient. Technology firms with data centers can't afford downtime in service to their customers. Manufacturers need steady production in service to their customers. Small businesses, like restaurants, retailers, and service providers, count on a stable power supply in service to their customers.

We've all seen what happens when the grid falls short. The winter storm this January was a clear reminder of the impact power outages can have on businesses. One of our Chamber members, Vintage Pizzeria, was among those affected.

A well-loved, local restaurant and an engaged member of our business community, they rely upon refrigeration to keep fresh ingredients ready for their customers. When the power went out, they faced the risk of losing hundreds of dollars in food, not to mention the destruction to their employees and their customers whom they serve.

And it's not just one restaurant. Businesses of all sizes felt the hit, from local shops to major employers. Nationally we know that power outages cause billions of dollars to businesses each year. And the Perimeter and Metro Atlanta is no exception.

This is why Georgia Power's 2025 Integrated Resource Plan is so important. It makes forward-thinking investments in battery storage, renewable energy, in grid modernization, ensuring backup power during outages, expanding capacity for new businesses and supporting sustainability goals that matter to our members of our Chamber. It's about keeping the lights on for everyone, from a neighborhood pizzeria, to global companies, like UPS.

The 2025 Integrated Resource Plan isn't just about keeping the lights on, though. It's about ensuring that the Perimeter and Metro Atlanta remain a top destination for businesses and talent for decades to come. This plan is a strategic investment in a prosperous economic future.

On behalf of the Greater Perimeter Chamber and as a member of the Georgia Chamber, we strongly support this plan and look forward to working alongside Georgia Power and the Public Service Commission to ensure that the Perimeter and Metro Atlanta remain powered for success.

Thank you for your time and your consideration today.

CHAIRMAN SHAW: Thank you, sir.

COMMISSONER McDONALD: Mr. Adam.

MR. FORRAND: Yes, sir.

COMMISSONER McDONALD: It looked like you had gone through the Integrated Resource Plan pretty carefully.

MR. FORRAND: Indeed.

COMMISSONER McDONALD: There are parts in there that are very controversial.

MR. FORRAND: Indeed.

COMMISSONER McDONALD: As you look at that, are you speaking in total that you like the diversification of generation that's in this plan?

MR. FORRAND: On balance, the plan is what we believe to be fair and equitable and to ensure the sustainability, the resilience, again, and the reliance -- the reliable energy that we need to continue to grow as an economy, both locally and regionally, as well.

COMMISSONER McDONALD: Reliability?

MR. FORRAND: Indeed, indeed. Thank you.

CHAIRMAN SHAW: Thank you.

Next is Steve Stroud, followed by Erin Lupuloff.

Good morning.

MR. STROUD: Thank you, Chairman. Thank you, Commission, for having me today. I am Steve Stroud. I'm a lifetime resident of Roswell, Georgia.

My role is president and CEO of Roswell, Inc. It's a 13-year-old organization. It's an economic development organization based in Roswell, serving the region of North Fulton.

My job today here is to talk to you about the importance of this IRP and what it means to the city of Roswell, what it means, more importantly, to our region.

As a business owner for 30 years, I ran a printing company in Roswell, Georgia. With the partnership of Georgia Power, I was able to power those presses and move things forward. But the importance of that was the infrastructure that they laid years ahead of 1978 when I opened that business. And what we found was that as we continue to grow in the region, Georgia Power has been there and they have planned ahead for what that looks like.

Unbeknownst to a lot of folks, even in Roswell, we're one of the capitals of car sales. $2.1 billion in 2024 in Roswell, Georgia. The importance of that industry and what that industry brings to the State of Georgia is phenomenal. In the city of Roswell, we have key electric dealers again that have popped up with their service centers, like Rivian that's been stalling right now.

Key pieces that are going to be part of the infrastructure of the $4.5 billion that Governor Kemp has put into the budget for Georgia 400. And electricity and the importance of what that does for our region for companies like GM that have invested in 2017, 1,800 employees and 226,000 square feet, all IT employees, that are building the infrastructure for autonomous cars or the -- what I will call the electric future of GM. So important in -- in Roswell.

So we see this as an opportunity for growth. We see the 400 Corridor as a growth engine for the state. And, more importantly, we continue to travel. As my duties as the International Economic Development Commission, or Council, I should say, as an accredited organization, I spend time all over the country and the one thing we hear is: You-all have Georgia Power. You have Southern Company. We wished we had a utility like that in our region.

Because what that does for our region, things like the foresight to continue on with Plant

Vogtle, it's phenomenal. So I say this: The support that you will have for the 5,400 businesses that are licensed in the city of Roswell is phenomenal because Georgia Power is there every day.

And this is not about my future and my business. It's about the future for my kids and my grandkids. So thank you for all your efforts and thank you for your service.

COMMISSONER McDONALD: Thank you.

CHAIRMAN SHAW: Thank you, sir.

Aaron Lupuloff, followed by Cherie Kurland.

And if I mispronounced anybody's name, please correct me and I apologize.

MR. LUPULOFF: Actually, that was perfect. So thank you.

CHAIRMAN SHAW: Oh, man. Thank you.

MR. LUPULOFF: Good morning, Commissioners and Chairman. My name is Aaron Lupuloff and I appreciate the opportunity to speak to you-all today on behalf of the Gwinnett County Public Schools Foundation and GCPS.

We are the largest school district in Georgia, serving over 185,000 students, with 25,000 employees, across 142 schools. Our district

depends on reliable, cost-effective energy. Our classrooms support digital learning and maintain safe and efficient school operations. Without consistent power, there would not even be internet at our schools or buildings.

As we prepare for the future, Georgia Power's 2025 Integrated Resource Plan, IRP, is a critical and essential step in ensuring that our schools and the communities we serve benefit from a modern, resilient energy grid.

First, affordable and reliable energy is essential for GCPS. Rising electricity costs directly impact our operational budget of over $3.6 billion, diverting resources away from classrooms, teachers and student programs.

A well-planned IRP helps student -- student energy costs, ensuring that our schools can continue prioritizing high-quality education, while managing utility expenses efficiently.

Secondly, GCPS is committed to sustainability and preparing students for the workforce of tomorrow. The inclusion of reliable and renewable energy investments, grid modernization, and energy efficiency is important for our curriculum of STEM-based energy education.

Many of our students will be the next engineers, technicians, and leaders shaping Georgia's energy future and we support policies that create learning and clear pathways for them. We need to make sure that our students become productive members of society. And without consistent energy, that can't happen.

Finally, the safety and resilience of our facilities depend on a strong energy infrastructure, whether it's ensuring HVAC systems function properly or securing school buildings are safe during extreme weather. We need a grid that can adapt to growing demands. Georgia Power's IRP moves us in the right direction by investing in grid reliability and clean energy solutions.

On behalf of GCPS students, teachers and families, I want to thank you for your time and consideration of our state's teacher and energy needs to support it. Forward-thinking investment in Georgia's energy future will strengthen our schools. It enhances learning, prepares the next generation for success.

A strong state energy plan ensures that people and businesses continue to come to Georgia. Our Gwinnett County public school graduates are ready to support the current and future needs of our economy and workforce.

Thank you so much for your time.

CHAIRMAN SHAW: Thank you, sir.

Cherie Curlin, followed by Steve Conner.

MS. KURLAND: It is Cherie, mispronounced all the time.

CHAIRMAN SHAW: Oh, I'm sorry.

MS. KURLAND: That's okay. Thirty-year career as a bank auditor, life-long Republican conservative, Georgia Power customer since 2006. Georgia Power bases much of its projected energy demand on the growth of artificial intelligence. AI depends on data centers.

AI hallucinations range from 15 to 60 percent, depending on use, and it is likely that AI answers will be more skewed, more erroneous over time. AI natural language answers seduce users into trusting it and help diminish our critical-thinking skills.

The data center industry says its buildings have a useful life of maybe 10 to 20 years, likely less, as new chip and server technology appear. Do Georgia Power models factor in this life span?

No one talks about the effects of China's competitive technology, such as DeepSee AI. No one will say what happens once those buildings can't be used. No one discusses the possibility of upgrading or remodeling the 5,300 data centers that already exist in the U.S.A.

No Georgia entity audits to see whether any promise made by the data center developers about energy use, pollution of any sort, carbon, articulate, noise, light, water use or jobs created is capped. But every state, including Georgia, that has tried to determine whether the huge tax abatements and subsidies given to data centers are worthwhile has found out that they are not worthwhile.

Please question Georgia Power's assumptions about power needs. Your staff is asking very good questions. The intervenors are asking very good questions.

Here is something you can do. The Court of Federal Claims awarded Alabama Power $100 million and Georgia Power $121 million last summer. In December 2024, the Alabama PSC ordered Alabama Power to return the award to its customers.

Commissioners, you have the power to order Georgia Power to credit back this $121 million to its customers. The Georgia Bulldogs may not always beat Alabama in football, but this is one way Georgia can beat Alabama. Please make that happen.

Accountability and transparency are non-partisan concerns. Please question whether Georgia Power, a monopoly, can truly justify its expensive trade-secret claims and data redactions from the public. Perception matters, especially in an election year.

Your voters, many Georgia Power residential customers, need you to serve them. As concerned commentator Erick Erickson titled his book: You Will Be Made to Care.

Thank you.

COMMISSIONER PRIDEMORE: Ma'am.

MS. KURLAND: Yes.

COMMISSIONER PRIDEMORE: So one thing that I just -- I don't think it's -- I don't think the news is getting out. And you being involved in conservative politics, I'm certain that you understand that what Republicans do most of the time just doesn't get covered in the media.

MS. KURLAND: True.

COMMISSIONER PRIDEMORE: It doesn't. And the transparency and the things that this Commission has done, they couldn't care less. But this Commission is what stands as the transparent and -- this very process that you're a part of today is the transparent and hard-working arm that holds the data centers accountable.

We've issued rules that make sure that bringing data centers to Georgia puts downward pressure on your bills and my bills and all of our bills, while at the same serving this important national security imperative.

So I hope that those listening or those that care will care enough to talk to their friends and neighbors. But at the end of the day, we've been working for years to ensure that the energy serving to data centers that this Commission oversees is transparent, and it's fair, and it makes the companies that are being involved in this that they pay, and you don't pay and others don't pay.

But it's something that we take very seriously, work very hard at. And hopefully as news will travel and people will start to pay more attention and that news will get to folks like you. I -- I always hate it when I see people that come down here to the Commission and they're stressed over something that has already been solved.

But if there is ever any way that any of us can assist you or help you, that's our jobs. That's what we do. So we'd loved the opportunity to do that.

MS. KURLAND: Yeah. And my suggestion -- I just gave this to someone with Georgia Power. I was in bank auditing and that is covered in acronyms. So one of its major challenges is trying to figure out how to translate all of the industry acronyms into something that some farmer in Waleska (phonetic), forgive me, can understand. And it is very, very difficult.

The January ruling that y'all have, my concern with that is that it does use the language: Georgia Power may at, Georgia Power's discretion, this might happen.

So the intent certainly is: Data centers, look, if you come in and you're using all these megawatts, you figure out how to make it green, payable, all of that.

I'm actually more concerned about the water use. The two out of the seven data centers that are in the pipeline now in the regional commission, just two of them will -- have said that they will use 533,000 gallons of water a day.

Now, the reason I bring up that is because House Bill 449 just passed out of the Senate Regulated Utilities Commission. So, guess what, y'all, yesterday was a slog for ten hours, imagine if you now will wind up with all of the private water systems, as well.

COMMISSIONER PRIDEMORE: We won't. They gutted the bill. They gutted the bill.

MS. KURLAND: There you go.

COMMISSIONER PRIDEMORE: It doesn't involve the Commission anymore and they're free to continue business as usual.

MS. KURLAND: Yay.

COMMISSIONER PRIDEMORE: But the rules -- the rules that the Commission passed in January, which were solidified off of an April 2024 decision, they're not "mays". They're "wills", they're "shalls".

MS. KURLAND: Okay.

COMMISSIONER PRIDEMORE: So 15-year contracts for data centers, as well as a pay of construction costs.

MS. KURLAND: Yeah. And that's where that -- of course, my background is in auditing. So I want to see that post-construction, that post-award audit that's done to make sure that, you know, if -- if Georgia Power has made a promise, if Microsoft has made a promise, if QTS, whoever. That if they say, "Yes, we're bringing these jobs. Yes, we're doing this, that and the other," that they actually do it. And if they aren't and if they don't, then they're accountable, so...

COMMISSIONER PRIDEMORE: This Commission will do it every three years in an Integrated Resource Plan, just like we're doing right now. But thank you.

MS. KURLAND: Thank you.

CHAIRMAN SHAW: Thank you, ma'am.

MS. KURLAND: Okay.

CHAIRMAN SHAW: Steve Conner, followed by Tori Gravley.

MR. CONNER: Good morning, Mr. Chairman and Commissioners.

CHAIRMAN SHAW: Good morning.

MR. CONNER: My name is Steve Conner and I own and operate two sawmills, DuPont Pine Products and Conner Holding in Homerville, Georgia, which is both in South Georgia. If you don't know where that's at, that's down --

CHAIRMAN SHAW: I know where that's at.

MR. CONNER: The two sawmills that continue to grow and the economy that we provide, jobs supported by the forestry in producing essential wood crop. In 2024, we expanded our operation in Homerville by adding a new pellet mill, an investment that required significant power, infrastructure upgrade.

Like any other business, we're dependent on reliable power in order to stay competitive, in order to ensure our employees have stable, well-paying jobs. The process of securing the necessary power for our expansion was challenging, due to the long lead times, critical components, like underground transformers.

However, thanks to the dedication of Georgia Power's team, which includes Barbara Goan, Brent James, Paul Phillips and Gene Croft, we were able to do this. And it was a team effort from Georgia Power to really do that.

And we -- we really ran into a lot of problems and they pulled it through. This experience completely demonstrates what long-term planning, investment in grid reliability, resource availability, key aspects of the IRP, are crucial to businesses like mine.

We need to ensure that we have adequate insurance -- adequate energy for the growth, which Georgia Power is building to plan ahead and invest in critical infrastructure. It's crucial to the success of our business.

I encourage the Commission to support the IRP to ensure that businesses like mine continue to grow and contribute to Georgia's economy with the confidence that our energy needs will be met both now and in the future.

Thank y'all.

CHAIRMAN SHAW: Thank you, Mr. Conner.

COMMISSONER McDONALD: Mr. Conner, you're in a business where the rubber meets the road in regards to what's happening at the top, i.e., the administration in Washington. There's a lot of conversation about lumber and tariffs. Do you have any thoughts of what's happening in that regards?

Is it positive? Is it negative? Or what is it going to do with your need to use the power?

MR. CONNER: Well, one example is Georgia has tremendous amounts of timber. I mean, we are very blessed. Most of it's south of Macon. Most of it gets cut south of Macon.

So there's a lot of need for energy in that area. The tariffs could be good or they could be bad. A lot of Canadian companies have came to the south and bought sawmills. So they have the double sword.

They've got milling in the south in the United States, in Georgia, all over the country. And they have them in Canada. To us in the private company that -- we really think the tariffs would be good, but we don't know that yet.

I think it's like the tariffs on everything. We're not sure. But we need the energy. The tariffs are going to be what they're going to be. So we'll know that shortly.

COMMISSONER McDONALD: Thank you, Mr. Conner. Your business is, like I said, the rubber meets the road.

MR. CONNER: Yes.

CHAIRMAN SHAW: Thank you, Mr. Conner. And you clean up nice for an old logger from South Georgia.

MR. CONNER: Thank y'all.

CHAIRMAN SHAW: All right. Tori Bradley. Good morning.

MS. BRADLEY: Good morning, Chairman and Commissioners. My name is Tori Bradley. I am the downtown development director for a very small town in the southwest corner of the state called Dawsonville, Georgia.

We may be a small town, but we rely on reliable energy infrastructure, just as much as any major city. That's why I want to express my support for the Integrated Resource Plan and the positive difference it is making for communities like ours.

For Dawsonville, having dependable, affordable power is just -- isn't just a convenience. It's a necessity. When the lights stay on, businesses can operate and families can live without worrying about sudden outages or high energy costs.

The IRP's focus on improving grid reliability and keeping rates stable is a lifeline for rural areas, like ours, where every dollar matters. I also appreciate the forward-thinking approach of the IRP. Investing in a balanced energy mix, including renewables, makes sure we're not just keeping up. We're preparing for the future. For someone like myself, it is a tool in my tool box to recruit and attract new businesses in creating jobs and ensuring our residents and future residents

have access to affordable, sustainable power right there at home.

For example, the EV chargers were brought into our downtown area about a year ago. And the 84 Corridor runs right through the middle of our town. Our downtown area is right off of that. So there wasn't a whole lot of reason to stop and visit our downtown.

But now that our EV charges have been strategically placed in the downtown, we have brought in a lot of out-of-towners through tourism. They stop, they charge their car, and they walk around the downtown. They patronize our local downtown businesses. And as a DDA director, this is a win for us in a small rural town.

I urge you to keep rural communities, like Dawsonville, in mind as you move forward. We may not always have the loudest voice in the room, but the decisions made here have a direct impact on our daily lives.

I thank you for your time and for your work in shaping Georgia's energy future.

CHAIRMAN SHAW: Thank you. And thank you for taking the time to come up here. I know it's not a short drive to Dawsonville.

MS. BRADLEY: It's not. But it's not so much the drive, it's once you get in the inner corridor here in Atlanta.

COMMISSIONER PRIDEMORE: Yes.

MS. BRADLEY: I also want people to live in small towns. That's where I'm headed.

COMMISSIONER PRIDEMORE: Thanks for coming all this way.

CHAIRMAN SHAW: Thank you.

That actually concludes the list. But if there is anyone else that did not sign up that wanted to address the Commission, then now is the time.

(No response.)

CHAIRMAN SHAW: Okay. Well, thank you-all to everyone that showed up and took the time to speak to us this morning. We're going to take a quick break and then allow the witnesses to get prepped and ready to go. And we'll get started in about five minutes. 10:19.

(A recess was held.)

CHAIRMAN SHAW: Okay. Good morning, again. We'll get started with cross-examination.

Before we move on, were there any housekeeping matters to take up?

(No response.)

CHAIRMAN SHAW: Okay. I'd like to remind the Panel that you're up -- you're still under oath and we will pick up where we left off yesterday.

It looks like the next intervenor up is Georgia Conservation Voters Education Fund.

CROSS-EXAMINATION

BY MR. ESTRADA:

Q. Good morning, good morning.

A. (Multiple Witnesses) Good morning.

Q. So just a few questions. I don't think they're going to be too rough.

Is Georgia Power pursuing any federal incentives flowing from the Inflation Reduction Act?

A. (Witness Mallard) I'll speak in the renewable arena. Georgia Power is pursuing all applicable funding from the IRA, as well as other funding that might be available from the federal government. As that applies to renewables, that would be for self-build projects. But, furthermore, we would expect that projects that bid into our competitive RFPs are taking advantage of all the resources that are available to them.

And so that has impacted our RFPs. We talked about that a little bit yesterday. Some of the uncertainty around those funds has created some uncertainty in the marketplace.

So we leverage them in the renewable arena for our own projects, but we also expect and know that bidders are counting on either tax credits or grants or other funding, as well, to support the economics of their renewable projects.

A. (Witness Beppler) And I'll just add that the direct answer is, yes, we've designed our programs to be able to stack some of those additional incentives, but not be dependent on those sources of funding for the success.

A. (Witness Goff) And one more piece of data for you. GEFA has been a regular member of the DSM working group process over the last couple of years. So to the extent funds are available, we want to partner in order to make it easy for customers.

Q. Okay. Just a few specifics on the programs themselves. Anything with the Energy Infrastructure Reinvestment Program?

A. (Witness Beppler) Are you looking for specific examples of funding?

Can you just clarify that?

Q. Yeah. So -- so essentially what I'm trying to get at is, like, how deep are you guys going into it, how aggressive are you guys pursuing it?

So I'm just asking specific. You know, I'm going to go line by line with about four programs. Just kind of give me, like, what Georgia Power is doing with each of these programs, if you could.

A. (Witness Mallard) Yeah. Okay. So please repeat.

Q. The Inflation -- I'm sorry. The Energy Infrastructure Reinvestment Program.

A. (Witness Mallard) Yeah. So I know the company is in pursuit of funds as it relates to supporting some power delivery activities, but not -- not our area of expertise. We're not going to have very much additional information about that. But I can confirm that the company is active in pursuing the funds to support some grid investments.

Q. Fair. What about the Transmission Facilitation Program?

A. (Witness Mallard) I'm just not -- I'm not sure.

Q. Okay. The Transmission Infrastructure Program?

A. (Witness Beppler) I think the transmission funding sources probably would have been better addressed to Witness Robinson on Panel 1.

Q. Okay. And the Grid Innovation Program?

I've just got to get these questions out.

A. (Witness Beppler) Same there.

Q. Okay. So your testimony included some of the programs that were up for decertification. I'm just going to go down the list of a few of them and just ask a few questions about them.

The Residential Refrigerate -- Refrigerator Plus Program, could you just tell us what that is so that we can have a good base?

A. (Witness Goff) Sure. So that was a program that we're currently implementing this cycle where essentially customers who had a second refrigerator or dehumidifier could get that picked up by the company for a fee. And so that resulted in energy savings, you know, as we recycle those old appliances.

Now, that is one that we're asking decertification of. What we've seen in the market is that the vintage of the appliances we're picking up are newer. And so there's less savings associated with what we're picking up. And, in addition to that, the costs are the same. So the cost-effectiveness of that program have really diminished over time.

Adding on to that, the contractor network has also been challenging. So it's really created a -- not the best customer experience. And so for those reasons, declining economics, not cost-effective, and the customer experience has declined, we are seeking decertification of that program.

Q. Do you guys have specific numbers as to how many people used these -- this program?

A. (Witness Goff) I'm confident we have those numbers. I don't have them here today.

Q. Okay. Do you know what area of Georgia would be the primary kind of consumers?

Would you say, like, urban, rural, this county, that county? Could you tell us that?

A. (Witness Goff) I'm so sorry. I know our implementation team would have all those details. I don't have them with me.

Q. Okay. So you mentioned cost concerns being a reason that you want to decertify; is that correct?

A. (Witness Goff) That's correct.

Q. Okay. And in your testimony, I believe you said -- or I believe it was said that it would be reallocated to other programs?

A. (Witness Goff) That's right. So we are seeking decertification of that program and then we're seeking the expansion of our other existing programs in the certification of one new residential products program.

Q. Okay. Any other resources coming out of the decertification of this program being allocated to -- in anticipation of the 2025 IRP being approved?

A. (Witness Goff) So we bring all of our plans forward to the Commission as part of this process. The demand-side process is an integral part of the overall IRP and so we do seek approval of our plans through this process.

Q. Okay. So I'd like to move on to the Residential Specialty Lighting Program. Testimony cites that resources are being allocated to the program. Could you tell us what those resources are? Is it monetary?

Is it capacity? Is it -- what would that look like?

A. (Witness Goff) Do you have a reference in the testimony?

Q. Somewhere, yeah. One second.

A. (Witness Goff) And if you don't, I'm happy to just talk through that program in general and why we're seeking decertification of it, as well.

Q. If you could while I pull it up.

A. (Witness Goff) Yeah. Sure. So the Residential Specialty Lighting Program is another program we're seeking decertification of. Lighting for years on the residential side has been a cost-effective way to get energy savings. So that program has provided many benefits through the years, but what we're seeing is that codes and standards have changed such that it's not really necessary to incent that behavior anymore.

So the cost-effectiveness of that program has declined. And so for those reasons, we're seeking decertification of that residential lighting program.

Now, there is still potential for lighting efficiency on the commercial side and you'll see that in our commercial programs. But the cost-effectiveness on the residential side is just not where it used to be.

Q. Okay. Is any of the -- and when I -- my reference is page 17 of the testimony. It would be lines 1 through 4 -- or maybe 16, as well. So starting on lines 25 on page 16 through 4.

And they're just general statements. I'm just asking for an expansion on them. Would any of the costs or any of the resources be reallocated to any of the data centers being proposed in this IRP?

Or any of the resources be reallocated in that direction?

A. (Witness Goff) So, in general, our DSM plans will go to serve the system. So whatever is approved through this process, that will allow the company to plan for less.

So to the extent the company has an overall resource need, DSM -- the approval of DSM programs reduces what we would otherwise need in order to serve our customers reliably across the state.

Q. But there's no specific, like, line item, "Okay. We take it from here. We put it over there," sort of analysis or statement that you could give?

A. (Witness Goff) So we do put -- and Dr. Beppler or Mr. Phillips could add to this. Our demand-side, our dispatchable demand-side options go on our resource ledger as DSOs. That information is included in the main filing. And then any energy reductions we get through our demand-side programs are incorporated into the forecasts. And so we are planning for less as a system as a result of these programs.

A. (Witness Phillips) Counselor, are you asking if the dollars what were allocated to specialty lighting are going to be reallocated to other energy-efficiency program?

Q. That, and any other resources vaguely described in the testimony.

A. (Witness Phillips) I think the dollars that were allocated to the Specialty Lighting Program, we are asking for additional dollars to support the energy-efficiency programs in our proposed case. And so those dollars would be repurposed to support the other programs or the other initiatives that we're seeking

approval for in this IRP, specifically for demand-side management.

Q. I guess what I'm getting to is: Are these programs being asked to be decertified so that we can -- so that those resources would be allocated to data center specifically if this 2025 IRP gets approved?

A. (Witness Goff) No.

A. (Witness Phillips) When you -- when you say reallocated to data centers, could you be more specific in what you're asking there?

Q. Well, it's more so like a direct -- is there a direct proposal, like, a one-to-one proposal from the -- is there a reallocation of the resources from these programs to what's being proposed in this 2025 IRP?

Is there a specific kind of transferred dollar? Do you guys have any sort of data on that or any plans specifically?

A. (Witness Goff) No. We are not -- we are seeking decertification of these programs because they're no longer cost-effective. That's not driven by the data centers. That's just driven by the economics of the programs themselves.

And so, as Mr. Phillips described, those programs are coming out of our budget request to the Commission and then we've introduced new programs and the

expansion of other programs in our demand-side plan for this process.

A. (Witness Beppler) And I'll just add there, even though there are particular programs which we're seeking decertification of, overall we're expanding the portfolio of demand-side options.

A. (Witness Phillips) And just one other point about speciality lighting. In the handout that staff counsel provided yesterday, Commissioners, specialty lighting, year-to-date, 2024 through the fourth quarter, I believe, had the second highest amount of energy-efficiency savings of any of the programs. Those savings are no longer going to be available because that program is discontinued because of some of the reasons that Witness Goff has shared today.

And so historically that program, as well as many of our residential lighting programs, have delivered significant savings for both our programs, as well as our customers. That's no longer possible.

So if you review the proposed case, you'll see we're having to go identify and secure those savings in other programs and in several areas more extensive energy-efficiency measures.

Q. Now, could you tell us -- and we're going to move on to the next program seeking to be certified or one of the other ones. The Commercial Behavioral Program, could you tell us what that is in short?

A. (Witness Goff) Yes. And so the Commercial Behavioral Program, like the Residential Behavioral Program, was intended to provide customers tips on ways to change their usage in order to result in lower energy savings on their bill.

As part of the 2022 IRP order, that was one that the company was instructed to do an evaluation for. And then pending the evaluation results kind of see what the future of that program would be. That evaluation deemed that that program was no longer cost-effective. And so to be in compliance with the 2022 order, we paused activity and we're seeking decertification in this case.

Q. Could you just go into a little about what made that cost-effective?

To most people, you know, small businesses getting a break on power is a good idea. Could you just go a little bit into what makes it not cost-effective?

A. (Witness Phillips) Well, I think the cost of the programs are greater than the benefits that we were able to identify. And if you're considering cost-effectiveness from a total resource cost perspective, then it simply means the costs are greater than the benefits.

Q. Could you expand on those costs and the benefits?

A. (Witness Phillips) I'm not familiar with all of the ins and outs and the details of the cost of that particular program, but there's the cost to administer it, the cost of producing the information. I would imagine there's probably some EM&V costs included in there, as well.

And so when we evaluate or measure the benefits -- the quantifiable benefits that we're realizing, as well as our customers are realizing, it did not outweigh the cost of the program itself.

A. (Witness Goff) Now, I will say there are other commercial programs available. So through our proposed case there's still the Commercial Prescriptive, Commercial Custom, and the Commercial SCDI. So we do still have a range of programs designed to -- to benefit our commercial customers.

A. (Witness Beppler) And I'd just like to add, the evaluations are done by an independent third-party. So it's not the company directly assessing the costs and benefits.

We're really contracting for an independent third-party to identify those costs and benefits and the cost-effectiveness of that program.

Q. And this may be a little repetitive. Any of the dollars, resources, going to that program or that were going to that program being reallocated directly towards the data centers proposed -- or the increased in data centers proposed in the 2025 IRP?

A. (Witness Goff) No. Data centers are not driving our decertification requests. Our decertification request on that program is based on cost-effectiveness. Those funds have come out of our proposed case and then we have new funds included in the proposed case to hit that 741 gigawatt-hour goal.

MR. ESTRADA: Thank you all. No further questions.

CHAIRMAN SHAW: Thank you, sir.

Next is Georgia Interfaith Power & Light and Southface Energy Institute.

Good morning.

MR. SHERRIER: Good morning, Commissioners, Panel.

MR. MALLARD: Good morning.

CROSS-EXAMINATION

BY MR. SHERRIER:

Q. A number of my opening questions were asked yesterday. So I only have two requests now about the residential and commercial solar and storage pilots.

First is: Can we get a shorter name for the program?

How are y'all referring to it?

A. (Witness Beppler) If that's the level of detail we're at, I think -- I think this is going to be a successful program.

Q. Well, the second thing is: As you finalize the details of it, would you consider expanding eligibility to include larger customers that may have complementary load profiles to the program?

So, for example, larger houses of worship that may not have, you know, as much as --

A. (Witness Beppler) As I mentioned yesterday, in the pilot it was residential and small commercial. And I think we've set that 250kW threshold to get familiar with the technology. We think that will be simple, easier to implement. But we anticipate getting learnings from that. And that's certainly something we could explore going forward is increasing the size eligibility once we establish some of the baselines of this program.

A. (Witness Mallard) We do have a program available for larger customers for customer-sided solar and storage. And so we've made a proposal to modify the customer-connected program to add storage as an option. And so that's a front-of-the-meter option, still

customer-sided, but wired directly off to the grid where a customer with the solar and storage enter into a long-term agreement with the company, but the storage resource would remain for resiliency purposes in times of grid outage for -- for those customers. So we do have an option for customer-sided solar and storage. Just a little bit different structure for the larger customers.

Q. Thank you.

Mr. Mallard, I have, first, just a clarification. How much storage was procured in the 2022-23 utility-scale RFP. So we've got Flint River, Wadley, Washington County.

A. (Witness Mallard) I don't believe any storage was procured, subject to check, with those energy-only solar procurements.

Q. I believe that Table C-5 in the IRP at page 132 classifies those as solar and storage.

A. (Witness Mallard) Yes. So in that -- that RFP, supply chain challenges required the company to present the Commission the option to extend the CODs, which we did. And so we gave it an extra year. That provided the flexibility that these developers needed to ensure the projects were viable.

Additionally, even though the projects were bid with solar-plus-storage, they had some challenges

through supply chain to get the storage resources. And so we made a modification to the PPAs that allowed the projects to come forward without storage, even though the requirement initially was to have storage.

Q. Okay. So there are no batteries at those three locations; right?

A. (Witness Mallard) Subject to check, I don't think there are.

Q. And you're not planning on them?

A. (Witness Mallard) They're able to meet the requirements of the PPAs as constructed.

Q. Thank you.

You said yesterday that the 1,000 megawatt initial target for the utility-scale procurements were based, in part, on your procurement expectations from ongoing RFPs?

A. (Witness Mallard) Partly, yes.

Q. What are the procurement expectations from ongoing RFPs and how did it inform your request in this IRP?

A. (Witness Mallard) So, again, I'll politely refrain from speculating on how many megawatts we might procure in the ongoing RFP that -- where we're getting close to negotiations with the PPA and any -- that information is restricted. I just can't talk about it.

But I will say that RFP, the 2023 utility-scale RFP, was seeking 2,875 megawatts. That includes some rollover from the prior RFP before.

Additionally, we're committed to procure at least 475 megawatts from the next RFP due to be issued this summer in 2025. That RFP will target the 475 and any unprocured from this current solicitation.

So I've got just a bit of a lining up of planes on the runway here. We're going to land the first plane in PPAs in the 2023 RFP and see how that informs the target for '25. And then ultimately the result of the '25 RFP will inform the next RFPs.

We've got 3,400 megawatts of solar on the ground. We're out for about 3,500 right now, all totaled, and then adding this new 1000-megawatt target as part of the long-term plan to get 4,000. It's a significant amount of renewables that are either in the process of being procured or that we're planning to procure by 2035.

Q. So how did it inform your request for 1,000 megawatts as a starting point?

A. (Witness Mallard) Yeah. I would say the 1,000 is probably more informed by prior RFPs. The largest procurement the company has ever procured in an RFP is 970 megawatts. Eventually one project in that procurement dropped out. So that procurement ended up procuring energy from 750 megawatts.

So there is an upper limit in the practicality of the total amount of resources that can be procured just through one process; the number of projects that developers can bring forward that can be evaluated for the transmission impacts and can ultimately be -- can ultimately be contracted for and brought online. So some of our learnings from prior RFPs have informed that 1000-megawatt target.

Q. And I do want to talk about those RFPs. But, I guess, I'm curious about the ongoing RFPs and how that informs.

A. (Witness Mallard) Yeah. I'm not going to even speculate about any results or potential results from the current RFPs, I beg your pardon.

Q. I'm not asking you to. I'm asking you how it informed your 1,000-megawatt request here, like in your testimony.

A. (Witness Mallard) I think that's the same question. I'm just sorry. I'm very respectfully going to decline to answer any questions about the ongoing RFPs and expected procurements.

Q. On page 78 of the IRP itself, you recognize multiple dynamic challenges in the procurement process. I want to walk through a couple of those.

What is Georgia Power's proposed solution to the transmission system capacity constraints?

A. (Witness Mallard) I think we heard a lot from Panel 1 about the strategic transmission initiatives and how Georgia Power is planning to expand the transmission system both to serve customer load and to facilitate additional generation. So I really don't have anything to add beyond what Panel 1 went through in a good amount of detail on the first couple of days.

Q. So you expect that to unlock additional solar capacity?

A. (Witness Mallard) I do. As well as some of the tools that we're putting forward, both utility-scale and DG RFP. Yesterday the mention of the SIGHT tool, which we think is a really big improvement that will help utility-scale solar developers identify locations on the transmission system that are more favorable for interconnection.

Q. I was playing on that tool last night. It's great.

A. (Witness Mallard) Yeah. It's cool.

Q. What is Georgia Power's proposed solution to the changing interconnection processes and requirements; that challenge?

A. (Witness Mallard) That really is referring specifically about the changing FERC-governed cluster interconnection process. So it's brand-new. Just very quickly, transmission interconnections traditionally have been through a serial process, or first-come, first-serve. And through FERC Order 2022, that whole process has been revamped such that now it's really targeting first-ready, first-serve.

And they do that through the cluster process. Once a year, projects will be gathered together in a cluster application period. That's actually happening right now. First one that we've conducted here in the southeast.

From that, those projects will be evaluated for the local interconnection costs. From there, projects will then understand what those local costs are and then we can evaluate them in our renewable procurement processes for additional costs that might be needed to deliver that energy to our customers.

So it's still somewhat uncertain exactly how that process is going to play out. This is the first one. We want to make sure that our RFPs dovetail into that new process. We want to make it as viable for developers as we can for them to get the projects interconnected and then successfully compete in our RFPs.

Q. So what I heard is that you're hoping the second cluster will be smoother, I guess; just a simple thing?

A. (Witness Mallard) Even -- even beyond that, we're down -- we're down in the weeds. What the company has proposed that hasn't been approved by FERC yet is something we came up with called a resource -- resource solicitation cluster.

This would be a cluster that would be specifically around projects that we're bidding in competitive RFPs. This overall process was developed by FERC probably based more on being responsive to other markets -- deregulated markets across the country.

And so with our competitive process, it's important to line up the timelines of interconnection with the RFP analysis. And so one day we hope to modify for this resource solicitation cluster process. Not approved yet.

And so until it is, we're going to -- we're going to go with the pro forma cluster process. We're going to make sure that we nest our RFP timelines into the timelines for that interconnection process as best we can.

Q. Thank you.

So shifting a little bit to the distributed generation RFPs. After the 2022 IRP, you made a map to help developers better identify locations to site the hosting capacity tool?

A. (Witness Mallard) Yes.

Q. Did any developers use that map?

A. (Witness Mallard) Oh, yes. Yes. It's got significant use. I can't quote the stats out of hand, but in this most recent RFP, significant number of projects used both the hosting capacity and the interconnection guidance tools that are offered in the DG market. We've gotten a lot of really good positive feedback from DG market participants about how beneficial those tools are to help them locate in the most -- most advantageous areas.

Q. So have you seen different outcomes because of it?

Did it reduce the amount of interconnection costs that bidders faced?

A. (Witness Mallard) I think it -- I think, yes. And, just as importantly, it -- it made the projects more successful. The number of projects that were -- were not successful drastically reduced because bidders were able to get this knowledge ahead of time and use that to inform siting decisions and maybe avoid some locations. Whereas, in the past without that information, they might have submitted a bid that would have been unsuccessful. So I have a much higher success rate with the use of these tools.

Q. Glad to hear that.

I guess, sort of quickly, yesterday this wasn't clear to me. In the, like, second phase of the subscription process and the first phase, you say there's a $5,000 fee in collateral for the utility-scale. And I'm asking: Do the fees and/or the collateral requirements apply to residential subscriptions?

A. (Witness Mallard) They wouldn't. So just to -- let's parse it out. For utility-scale CARES, it has been a $5,000 application fee. We're not proposing to change that. Although, feedback from the marketplace and from participants could change that eventually.

For DG subscriptions, we haven't identified the amount yet, but it would be somewhat less than 5,000. For residential customers, it likely wouldn't look anything like that. It would likely be something more akin to a fee that aligns with residential commitment and the value that they would get from a subscription that would likely be from a 1 or 2kW watt, that type of thing. So we haven't developed that yet. It would be a much lower amount.

And just one more comment on the collateral. The collateral, if that wasn't clear, that will only be required in phase three projects if PPAs are out of market. So if we're able to get PPAs to bid in down to that market price, that total net benefit, there wouldn't be any need for collateral.

But if we're going to enter into a PPA that's higher than that market price and we're counting on the customer subscription to offset that over time, those things could have different terms, they could have different conditions. We want to make sure that if the customer in some way defaults or doesn't live up to their end of the agreement that we've got that money on hand to draw on and protect other customers from any -- any negative economic impacts.

Q. So there will be a fee for residential customers to subscribe. Could you ballpark that?

A. (Witness Mallard) I really couldn't at this point. I think we'll take a lot of things into account this week as we consider that. We'll think about our current community solar program.

We're definitely studying other community solar subscription-type programs in other places. And we'll take feedback from all stakeholders, both developers and potential customers, as well. So more to come there.

Q. You don't ask the Commission to make any changes to the existing community solar programs in this IRP?

A. (Witness Mallard) That's right.

Q. And I want to follow up on Commissioner Echols' question from yesterday. The income-qualified community solar program that was approved three years ago --

A. (Witness Mallard) Yes.

Q. -- where Georgia Power would find a corporate sponsor to pay part of the subscription so that the customer would see bill savings, you said yesterday that you still haven't found any sponsors, but that you have had and are having conversations -- conversations with prospective sponsors.

What -- what feedback have you gotten?

A. (Witness Mallard) Generally the feedback is that either -- that sort of the connection, the sponsorship value of being able to point to additional carbon savings or rent procurements, that type of thing, is maybe not close enough. And then, also, the economic proposition, the amount of the buydown in relation to value of the reqs and the good-will that would be earned from a sponsorship.

Q. Are those the only two reasons that that concept is turned away?

A. (Witness Mallard) I don't -- I wouldn't say that's an exhaustive list, but those are the ones that come to mind.

Q. Have you incorporated that feedback into the new program proposal?

A. (Witness Mallard) So a couple of ways. That -- the requirement for an income-qualified sponsor, a buydown, is not dissimilar to the ways that we're looking at providing opportunities for third-party funding, both from the solar-plus-storage program, but also the new residential distributed community solar program.

We're going to make sure the program design creates opportunities for third parties, whether that be corporate sponsors, whether that be access to funding from federal government or other places. We're going to ensure that the program design allows for that.

Furthermore, the sort of value proposition to the customers is going to look a little bit different. The customers willing to lock into a longer agreement, then there's a chance that the cost of that subscription -- the net cost of that subscription decreases over time and creates an opportunity for -- for more access. It reduces the total out-of-pocket costs for customers if the rewarding cost could go up over the term of the subscription.

Q. You say on page 99 of the IRP that you're exploring opportunities to partner with third parties to

reduce subscription prices for lower-income customers. How is that different from the existing low-income -- or income-qualified community solar program that has not found any sponsors?

A. (Witness Mallard) Yeah. So there are a couple of differences. Primarily the new program is going to be supplied from new resources and new resources that are most likely going to be owned by third parties. And so these would be incremental or additional megawatts added to the grid. That creates a little more value for potential sponsors.

This will be new projects added to the -- added to the grid. And if we can create a sponsorship, it creates a lot of demand for income-qualified customers. There's the ability to not only fill up the residential community solar allocation of 10 megawatts per RFP, but even grow beyond that.

We envision if the -- there's enough demand, there could be a sort of self-serving continuous process where we continue to increase the amount of megawatts if demand does increase. That would allow third-party sponsorship the ability to help drive enrollment and drive additional renewable energy added to the grid. Again, that's -- the additionality concept, making sure that money that they're spending creates new resources, is very

important to a lot of these corporate sponsors.

Q. I want to go back to page -- well, I guess we're on page 99 of the IRP. Up at the top, though, where you talk about the subscription and bill credit for the proposed community solar.

A. (Witness Mallard) Yes.

Q. Ms. Brown asked you to translate it yesterday and I'm going to ask you to translate it again today.

A. (Witness Mallard) Okay.

Q. Because I still don't understand --

A. (Witness Mallard) Okay.

Q. -- what a credit calculated from the annual average value of the distributed generation facility's production based on the company's hourly operating costs per kilowatt hour means.

A. (Witness Mallard) I will make it as simple as I can. It's almost exactly the way the RNR annual amount is calculated today. RNR is calculated today based on all 8,760 hours of the year and a projected solar load shape against the projected system cost.

So instead of having to calculate that every hour on actual costs, like we do for utility-scale CARES, what we would propose to do here is do a calculation similar to RNR. It might be a little different, but it could be some differences in the components of the calculation.

We're going to estimate that once a year, come up with a fixed amount, and then that way that single amount would represent the average value over all solar hours for the whole year. So very similar to the way that the RNR calculation works today. We don't measure RNR customers hourly. We measure their kilowatt-hours and pay them on an average of data once a year.

Q. What different components are you referring to?

A. (Witness Mallard) It's hard to say at this point. RNR has a very specific required formula that includes some components beyond the rewarded energy costs. I would -- I will tell you that most of the value there is avoided energy cost. But some of the other components could be different, could be -- have more or less components added, depending on the final design of the program, and ultimately depending on how that payment structure is accrued.

Q. You said yesterday it might be on a seasonal basis or an annual basis. Why not monthly if that's the billing cycle and if this is a community solar program where folks might want to subscribe, dip out?

A. (Witness Mallard) Yeah. It's just weighing the pros and cons. The more you update it, the more administratively burdensome, the more costly, the more -- the more it changes for customers. I mean, some customers would appreciate knowing what that amount is for a year and having that locked in. Other customers might appreciate seeing the seasonal variability.

But, just as an example, a credit could be significantly more in July with a lot more solar resource than it would be in a December or a January when there's not as much energy produced from a solar facility. So the customer would see a lot more variability if we updated it.

A. (Witness Beppler) And I will just add on the subject of monthly potential, even though customers receive monthly billing cycles, those don't align for all customers. So it's a sort of revolving monthly cycle. It doesn't necessarily align with the calendar month. And so that would add a significant amount of complexity to implementation.

Q. Okay. I suppose I thought it was for their billing month.

You mentioned avoided costs going up. And then yesterday you said that because of that there might be a threshold or a cap on the credits that subscribers could see here.

Could you explain that a little more?

A. (Witness Mallard) Yeah. I think that would likely be applied to the utility-scale and distributed generation subscriptions more so than the residential. But we haven't -- we haven't completed that analysis or made that final suggestion.

The point of instituting protection against cost shifting is if avoided costs go up more than what we have projected, there is a risk that subscribers -- subscriber's credit could be more than the subscription price that they're paying. And in that way that shortfall could flow through the fuel bucket and impact nonparticipating customers.

So what we're proposing here, and, again, just in concept, is a cap or a collar or some term limits. We've got a few -- a few ideas that we're working on that would be fair and reasonable improvements to the subscription methodology that would protect nonparticipating customers.

A. (Witness Beppler) And, Commissioners, I think the intent there with that design element is consistent with many of our programs to share the benefits between participating and nonparticipating customers.

Q. Okay. I -- maybe you both can help me reconcile two things that you just said. Because what I heard Mr. Mallard say is that there's a risk the credit could be more than the subscription, which I hear as bill savings for the subscriber. And, Mr. Beppler, you said sharing those things.

So how do y'all reconcile those two?

A. (Witness Beppler) Yes. So I think, as Witness Mallard described, the original design is based on an avoided cost projection. To the extent that that changes, the relative value between the credit and the subscription price will also change.

To the extent that there are more benefits that accrue, we would want some of those to be recognized for participating customers. We also want nonparticipating customers to share in the savings of these resources being procured.

A. (Witness Mallard) And, again, I'd just add that that likely comes into play on longer-term agreements. Residential customer I would expect a 5- or a 10-year term would be what would be typical. It would be unlikely to see significant change in the avoided costs compared to projections.

What we're looking at are some long-term projections. We offer a subscription through CARES anywhere from 10 to 30 years. So if a customer subscribes for a really long term, there's a chance that in the out years, especially the credit that they're getting, is significantly more than the subscription price that they're paying. That's the -- that's the sort of potential cost shift that we want to make sure that we address through a subscription change.

Q. So the new community solar program that you're proposing could result in bill savings for the subscriber?

A. (Witness Mallard) I think it could, yes. Depends on -- depends on the trajectory of the avoided cost and the price of the solar that's procured. The price of the solar that's procured through the competitive RFP is the basis of the subscription price. And then the avoided costs are what they are as the costs change.

Q. You described the new program yesterday as providing optionality, like an additional choice in reference to the current community solar program?

A. (Witness Mallard) Yes.

Q. Which you don't recommend the Commission modify in this docket?

A. (Witness Mallard) That's correct.

Q. Why would anybody subscribe to the current premium program where they're paying more if they could subscribe to this program where they might see savings?

A. (Witness Mallard) I think customers have a lot of different drivers for what convinces them to

participate in a renewable energy program. The current community solar program is meant to provide optionality for customers who want to support solar, who want to access the benefits of solar, and get those real energy credits retired on their behalf.

It provides that optionality. It's from existing resources around the state. There's three facilities, 8 megawatts. It's available right now and today.

Once the other alternative, if approved, gets in place, I think the company would take into account: Are both options needed? Do they serve any different customer needs? Would there be ability to sunset or modify the existing program?

We just don't know that yet. And it's going to be a few years before we do. If the -- if these programs are approved, the next DG solicitation would be in 2026 and 2027 with resources not coming online until '27-'28 time frame. So we've still got awhile before subscriptions would be available through the new program and approved.

Q. Okay. It's Georgia Power's position that the renewable cost-benefit framework, the RCB framework, establishes the value of energy that renewable resources deliver to the grid?

A. (Witness Mallard) Yes.

Q. In RCB framework you look at the costs and the benefits of solar resources?

A. (Witness Mallard) Yes.

Q. Including distributed generation resources, like those in the community solar program; right?

A. (Witness Mallard) Yes.

Q. In the RCB framework, whether we agree on the, like, specifics of it or not, has found every time that solar resources provide a net benefit?

A. (Witness Mallard) Depends on the price you pay. You can't calculate whether there's a benefit or not until you know what you're paying for that resource. And so a resource that's procured competitively when compared against an NG0 avoided cost or different scenarios of avoided costs, that's what informs whether a benefit is created.

Q. So that 3- to 4-cent number, how does that fit with your statement?

A. (Witness Mallard) Yes. If we can procure solar at that number, then benefits are created.

Q. Okay. Why can't Georgia Power offer a community solar program where the subscribers pay the costs that we just talked about and those same subscribers see the net benefits as bill savings?

A. (Witness Mallard) That's exactly how the new distributed generation community solar program is designed. That's exactly what it's intended to do. Procure solar at the least possible cost, allow the subscriber to cover the cost of that procurement, and then get a benefit based on that renewable cost benefit framework calculated avoided cost. That is the essence of the proposed program.

Q. The essence. But are you saying that the proposed program will result in bill savings?

A. (Witness Mallard) It depends on the avoided cost. It depends on the relationship of the cost of the solar. And so utility-scale solar -- for a long time we were procuring at the 3-cent range, maybe 4-cent range. Inflationary pressures are acting on everything these days, including utility-scale solar.

Same with DG solar. We've seen DG solar procured in the 5- to 6-cent range, but time will tell and our RFPs will tell exactly what the market can deliver. But the relationship between what solar can be procured for and what the value is, as calculated by that avoided cost, that's the resulting cost or benefit that customers can access -- get access to the renewable energy credit and the potential savings, depending on the relationship of those two things.

Q. Staying with the RCB framework, there's a category now that says: Energy only solar resources, which you're treating differently based on a quote: Obligation to perform.

So you're saying: We're going to pay energy only solar resources less because they don't have an obligation to perform?

A. (Witness Mallard) Can you point me to where you're referencing that?

I'm not on the same page.

Q. This is the RCB framework at page 2.

A. (Witness Mallard) In the main document?

Q. It's in the Technical Appendix.

A. (Witness Mallard) Yeah. I'm sorry. I don't have a copy of that with me.

Q. Are you aware of the new energy only category?

A. (Witness Mallard) Yes, I am. I'm generally familiar.

Q. You define the obligation to perform there as having specific performance obligations and remedies for non-performance?

A. (Witness Mallard) Yes. Basically a solar resource either under company ownership or control, or procured through a PPA, that has appropriate remedies that

ensure the performance of that -- of that solar resource.

Q. Do current solar PPA contracts meet those requirements?

A. (Witness Mallard) Yes. Yes, they do.

Q. All of them?

A. (Witness Mallard) Well, I can't say all of them. Over time we continue to involve -- evolve our procurements. And so older PPAs might not have quite the same peak in them that the new ones do. But I can confirm to you that utility-scale, RFP procured solar, DG RFP procured solar, all of those PPAs have appropriate remedies and requirements for the counterparts to perform.

Q. And going forward, as well?

A. (Witness Mallard) Yes.

Q. What about the -- what we call the virtual power plant program; are those going to get the capacity credit, as well?

A. (Witness Beppler) Can you be specific by what you mean with virtual power plant program? I don't think we've referred to anything as virtual power plant program.

Q. The residential and commercial solar and storage pilot.

A. (Witness Beppler) Small commercial, yes. Solar-plus-storage.

And repeat your question on -- the question.

Q. Are those considered energy only or are they considered a combination?

A. (Witness Beppler) By definition, those have storage associated with them, which would be beyond just energy.

A. (Witness Mallard) We do anticipate the contract language to have performance requirements and for appropriate remedies if the projects don't perform.

Q. Can you give me an example of when a solar resource on the system now has failed to perform?

A. (Witness Mallard) Yeah. I can't give you specifics, but, Commissioners, my team is responsible for the administration of all of the company's power purchase agreements. On a monthly basis a significant number of these counterparts fail to meet their performance requirements.

We work really closely with these counterparts to come up with solutions. There's any number of things that can go wrong. We've got inverters that go out. We've got tracking mechanisms that fail to perform, damage from storms.

There's a never ending -- I think we are now up to nearly 600 DG PPAs these days to administer and a pretty continuous stream of projects that for one reason or another fall out of compliance.

We work with them to either get them on a different program, move them off to another program that better meets their availability, or work with them as they work on remedies to be able to bring their project back in compliance and produce the amount of energy that we were counting on when we chose those projects through a competitive RFP.

VICE-CHAIRMAN ECHOLS: Are those developers paying liquidated damages when they don't comply?

Is that something y'all are enforcing or not enforcing?

MR. MALLARD: No. We are. There's some -- a little bit of a grace period. In fact, one year out of compliance and you get a warning letter. On the second year, then we trigger some action.

We're working on something right now that will be before the Commission pretty soon, which will be an alternative. There's a lot of these older PPAs way back from -- gosh, I sound old -- 10 years ago now where those projects are getting some age on them.

Some of them are owned by counterparts that are not used to being in the solar business, just somebody who might own one at their home or business, not a professional long-term solar owner.

We're working really hard to come up with a creative solution so that we can keep them under contract and keep that energy and those reqs coming to us, but that we pay -- we pay them a different price, a discounted price, based on the production that they're actually able to achieve.

VICE-CHAIRMAN ECHOLS: Don't they typically overbuild a little bit, though, to compensate for that?

MR. MALLARD: I think typically they do. The very old PPAs, Commissioner, just have an annual capacity factor that they have to meet and they have to stay within that range. The newer ones, they give us an annual delivery percentage. So they estimate what they're going to give, then the concept is the same.

They have kind of a dead ban if they stay between 90 and 110 percent. The payments go as contracted. It's the ones that fall below 90 percent and then some of the PPAs have default provisions if they fall below a certain production below that.

BY MR. SHERRIER:

Q. My last question for you. Has Georgia Power reconsidered whether to include fuel as a hedge?

Capture the monetary value of the fact that generation from renewable resources lowers the cost of fuel. Have you reconsidered whether to include that as a benefits in the RCB framework?

A. (Witness Mallard) You know, we have. But the RCB gets teed up and evaluated every RFP and approved. Fuel hedging is something that was talked about last cycle or a couple of cycles ago.

It's our testimony that the RCB is accurately calculated. The way that we project those avoided energy savings and the other components accurately reflects the benefits that solar provides to the system. So, no, we haven't -- haven't proposed any changes related to the fuel hedge.

Q. Okay. I would like to turn to demand-side management and thank Georgia Power. We are very glad to see the savings anticipated from the Vogtle settlement in the proposed case. Thank you.

On page 45 of the IRP, it says: The level of energy efficiency in the proposed case was set to 0.75 percent of the total energy savings. The Vogtle settlement set 0.75 as a floor.

Did Georgia Power evaluate whether a higher amount of savings would also be cost-effective?

A. (Witness Goff) To achieve .75 annual budgets it requires annual budgets of 570 to $580 million per year and it requires TRC waivers on four of our programs.

The incentive levels included in that budget are based on Georgia Power's technical potential study. And so to go above .75 percent would make an expensive case even more expensive. So for those reasons we stuck with the 741 gigawatt-hour per year target.

Q. Got it. But yesterday y'all pushed back on the comparison to other utilities that achieve higher savings saying that there were different factors in most states.

What factors should be considered when comparing states' DSM success?

A. (Witness Goff) I don't know that it is appropriate to compare across states. Again, for the reasons that we laid out before. Each state may have different priorities, legislative environments, you know. There's just so many different factors.

It is important to compare best practices. That's one reason that we engage with the industry. We employ a third-party design consultant who has expertise across the industry. But when we bring plans forward, we do it through the Commission's DSM program planning process and what works within Georgia based on our history in implementing these programs for many years.

Q. One of the things that you said yesterday about maturity of the program, those aren't relevant to comparisons?

A. (Witness Goff) Yes. So we have been at this, like I mentioned yesterday, since 2011. We have delivered 4,700 gigawatt-hours of savings since that time. Our programs are mature.

We have many years of implementing these programs with a high degree of customer satisfaction. We don't always know where other utilities are in that maturity model.

Q. Right. That's what I'm asking about. But if you did know that, could you then factor that into a comparison?

A. (Witness Goff) No. And, again, as Commissioner Pridemore mentioned yesterday, there could be other funding that's being applied from a state level or other reasons. I mean, there's just so many different factors that when you go state by state it -- it just doesn't make the comparison an apples-to-apples comparison.

Q. What utilities does Georgia Power see as its peers in the demand-side management arena?

A. (Witness Phillips) I'm not aware of any specific utilities that we consider as a peer in the DSM space. I mean, we -- we developed the proposed case in accordance with the Commission-approved DSM program planning approach.

We did that for this IRP and we've done that ever since 2010 when the DSM program planning approach was implemented. And so we develop our case given the guidelines set forth by this Commission without a lot of other review or research regarding other utilities or states.

A. (Witness Goff) But just to reiterate, it's informed by historical performance, evaluation results, the DSM working group process, Commission staff, third-party design consultant, implementation feedback from working with customers.

So we do incorporate a lot of feedback. We engage with the industry. But there's just so many factors when you try to compare apples to apples, savings and budgets, that it doesn't make that appropriate.

Q. Thank you.

COMMISSIONER PRIDEMORE: Isn't weather a big consideration in that, as well?

MS. GOFF: Yes.

COMMISSIONER PRIDEMORE: I mean, on DSM I would think that it would be.

MS. GOFF: Weather, yes.

COMMISSIONER PRIDEMORE: You can't compare to North Carolina's climate. Temperature is different. You can't compare it to Florida.

So you've got similar utilities that are integrated and best run utilities. You have a weather balance in there that, again, it's not an apples to oranges -- it is an apples to oranges.

MS. GOFF: Saturation of different home types, that could be a different -- another factor that varies across utilities.

BY MR. SHERRIER:

Q. I want to ask about the incentives in the proposed plan and how you got there. You said that it was based on the TEAPOT study. Please stop me when I get it wrong here; okay?

So the TEAPOT study, it looks at the measures that are out there, like ground source, heat pumps, and it looks at which measures are economic. And then it narrows those down to what is achievable in Georgia.

To determine whether it's achievable, the TEAPOT study looks at different incentive levels; the 25 percent, 50, 75, and 100. So to hear you picked 100 percent for the incentive levels for all the measures because of that?

A. (Witness Phillips) So we chose 100 percent

incentive level to help reach the .75 percent of retail sales for the proposed case. Specifically when looking at the most recent TEAPOT report, for the year 2025, in order to achieve .7 percent of sales in that year, it would have required a 100 percent incentive level.

A. (Witness Beppler) And I'd just like to add, on the TEAPOT study you started with the economic screening. There's a stage before that, which is the technical potential. So that's the first level of the screening, which then goes into the economic potential and then the achievable.

Q. And you didn't stop me because it started after that.

So you just picked 100 percent because of that and put it on to all of the programs and measures here?

A. (Witness Phillips) Well, I think that was one data point that the TEAPOT helped confirm. And then, as Witness Goff said, working closely with our consultant AEG, working with our program managers who have administered these programs for a number of years, working with our trade allies. Many of those factors went into consideration when setting the budgets for this proposed case.

Q. So some measure of judgment. Was that, like,

measure by program?

A. (Witness Phillips) I don't know that it was necessarily by measure. Because when we work with our design consultant and when we work with our program managers, what we're trying to do is take the individual measures and package them into a program that we can then present to our customers.

Before we do that, we present the programs to this Commission for review and approval. And so there is the -- there's the research, there's the analysis, there's also an understanding of the market in Georgia. Because what we're trying to do is package programs that we can then present to our customers, both the residential and commercial, such that they can apply within their home, within their business.

And at the same time, package the measures and the programs so that we're trying to minimize the administrative costs. And so we go to market with as few programs as we can, but at the same being flexible and offering a number of solutions to our customers, both residential and commercial.

A. (Witness Goff) And I didn't hear when Mr. Phillips initially said judgment. You said judgment. But this is, again, a very collaborative process. The DSM working group process is very collaborative.

As we go to an RFP to select an implementer, all those design plans are shared with staff prior to us going and implementing to get feedback from them. And so it is judgment, but it's not just the company's judgment. It's the culmination of the entire process.

Q. Okay. On your testimony on page 13, lines 24 to 28, you say the company doesn't support the inclusion of an industrial DSM program because industrial customers generally adopt energy efficiency on their own.

Do you recall in the 2024 TEAPOT study we were just talking about what percent of achievable energy savings were industrial?

A. (Witness Phillips) Right offhand I don't know. I know that information is included in the TEAPOT study. But you're correct. There are no industrial programs in the company's proposed case.

As noted, we know a number of our industrial customers are installing energy-efficiency measures in their facilities without having a customer-funded, company-sponsored energy-efficiency program. We engage with these -- our industrial customers every day through our managed accounts organization, our external affairs organization.

We are plugged into them, to their business. We have a significant impact on their business for a reliability standpoint. And so we have strong relationships with these customers. We know that they are making these improvements. And so they're doing that without having incentives offered by the company that are also funded by the customers.

We also consider when developing the proposed case past guidance from this Commission. And in previous IRPs, this Commission has approved orders that did not include industrial programs; only residential and commercial. So that's also considered in developing the proposed case.

Q. But is it fair to say that based on Commission market research, TEAPOT study, that there is cost-effective and achievable energy and demand savings in the industrial sector?

A. (Witness Phillips) Yes, that is accurate. And I think that's not only accurate for the most recent TEAPOT study, previous TEAPOT studies have also quantified the potential for energy efficiency in industrial customer's facilities.

A. (Witness Goff) And I --

A. (Witness Beppler) Witness Phillips mentioned this, but these are large, sophisticated customers whose energy usage has a significant impact on their bottom line. To the extent that they identify cost-effective improvements for their own individual businesses, they are continuing to make those investments outside of a utility-sponsored program?

A. (Witness Goff) Right. So it's not that anybody is arguing that there's potential in the industrial space. It's that there's not a need for a utility-funded program in order to incent that behavior.

Q. Y'all mentioned the program planning approach to develop the DSM cases; right?

But this plan is different; right? It includes a fourth case that you're calling it a capacity and affordability case?

A. (Witness Goff) It does. And this IRP, consistent with past IRPs, there are various options for the Commission to consider. And so in the company's application we have included our proposed case, the supply-side options, the advocacy case, and then the capacity and affordability case.

Q. Has Georgia Power filed four cases in any of the last five IRPs?

A. (Witness Phillips) Not that I'm aware of. We have filed additional sensitivities to provide the Commission guidance on how economics could change, depending upon whether you're evaluating it in an MG0 or -- in the previous IRP, if we evaluated economics in an

MG0 and MG20.

In this case -- in this IRP, we're evaluating economics on an MG0 and a 111 MG0. And so we have provided additional sensitivities, but I'm not aware that we have provided or filed four cases previously.

A. (Witness Goff) But it's not unusual for the Commission to have options to consider.

Q. When did you inform staff that you were filing a fourth case?

A. (Witness Phillips) I don't recall the date.

Q. Why didn't you inform the demand-side management working group that you were developing a fourth case?

A. (Witness Goff) So the capacity and affordability case is a sensitivity. It's not a brand-new case. It's a subset of programs that are in the company's proposed case.

So just to kind of level set, in the company's proposed case we're targeting 741 gigawatt-hours per year at annual budgets of 570 to $580 million. That compares to $90 million in our current plans.

That's a lot to ask. And so the capacity and affordability case is a subset of programs. It includes programs that benefit -- that generate the most capacity benefit and target customers in the most need. It has

annual budgets of $140 million per year. So it's just a subset of programs.

The only unique elements to that case, as compared to the proposed case, are the inclusion of a small team of energy auditors. So there's some funding set aside, a little over $1 million per year, for a small team of energy auditors, and a little bit of funding -- a little less than $1 million a year for an online residential audit tool.

And so the inclusion of those two elements are the only thing that is unique, in terms of the -- the cases. It's just that there's a smaller subset of programs that are included in that case, as compared to the proposed case.

Q. I suppose I will ask again. Why didn't you inform the demand-side management working group that you were developing a fourth case?

A. (Witness Phillips) I was not aware that the DSM working group had not been informed. I know staff had been informed.

But we did work closely with the DSM working group on the proposed case, as well as the efficacy case. And so we did incorporate some of the feedback in those cases. But I can't speak to -- to when the capacity and affordability case was communicated.

A. (Witness Goff) But, again, it's just an option. The Commission has lots of options. That's not unusual for any IRP. It is a subset of programs. It's not a brand-new case.

And so all of the information is very consistent with what is in the proposed case. It just is a smaller subset with smaller annual budgets.

Q. When did you begin developing this case?

A. (Witness Phillips) I don't know when specifically we started developing the capacity and affordability case. And as Ms. Goff said, it's a subset of the proposed case and incorporates the same programs, just at a smaller scale. I don't know the date when that began -- the analysis began for that.

Q. Was it in 2024?

A. (Witness Phillips) Yes. I would think so. It would have been in 2024.

Q. That you began developing the forecast?

A. (Witness Phillips) Yeah. I don't know specifically when. But in late 2024 I know we updated the economics for all of the measures that were included in the proposed case. That was done in December.

And so the -- as I said, the capacity and affordability case is a subset of the proposed case. And we were still finalizing and developing the proposed case as late as mid December.

Q. Now, shifting gears, when you predict savings in the proposed case, say you do efficiency upgrades at an old house, how do you measure that?

Like, the old house itself, that one got this many kilowatt-hours saved, or do you compare it to some other baseline?

A. (Witness Goff) Are you speaking of a specific program within the case?

Q. Generally. That was just an example.

A. (Witness Goff) Okay. So, in general, we would use evaluator results, if we had them. Or to the extent we didn't have evaluator results, there would be some kind of, like, engineered model calculation to come up with those savings. And each program may have different requirements, you know, that -- that savings are generated in order to receive those incentives.

A. (Witness Beppler) And I can expand a little bit on the modeling front. So as Commissioner Pridemore mentioned earlier, some energy-efficiency measures are particularly weather sensitive. And those are the subset that we tend to evaluate using a program called OpenStudio, which is a Department of Energy created modeling framework that allows us to simulate the impacts of energy efficiency when you add an energy-efficiency measure to a home or business. And so that informs some of the savings estimates for those weather-sensitive measures.

Q. So do you compare it to, like, the code as the baseline or do you compare it to, like, the individual house you just did the project on?

A. (Witness Beppler) We have a set of models that serve as a baseline based on what is the current code and standard for both existing construction and then separately for new construction.

A. (Witness Phillips) And those are based upon representative businesses, as well as residences, both for single-family and multifamily. And so it's not specific to any one location or home. It's modeled against a representative facility or building.

Q. So there could be more savings not captured in the model here if you do a program at a house that's not up to code?

A. (Witness Beppler) There could also be less savings if you had a particularly efficient home that you were looking at. So I would say that there is variability on both sides. What we do is develop representative models and we do baseline those to the territory to ensure that the model results are giving us profiles and annual energy usage that align with the usage of our customers.

A. (Witness Goff) And, again, if we have evaluator results, then we will use those.

Q. Do you think measuring from a code captures the above and below; is that why you use it?

A. (Witness Beppler) I think that represents an accurate baseline to establish the savings potential of measures that are above the sort of code default.

So one of the things that we've talked about, Commissioners, previously is that we have seen transformation in the market where some of these energy-efficiency savings potential are reduced because the sort of minimum or baseline equipment has gotten more efficient over time. And so establishing those reference points as the standard efficiency options is appropriate to measure the savings of those energy-efficient measures.

Q. Okay. Switching again, looking at the proposed commercial custom program, if all the -- so this is where you go to, like, a commercial business and you work with them to make specific changes in their property. Shouldn't that, by definition, be cost-effective?

Why does it need a waiver?

A. (Witness Goff) For the commercial custom program?

Q. Yeah.

A. (Witness Goff) So if that program -- so the customer -- just backing up history. The commercial prescriptive program is almost like a menu of options. It's if you install this measure, you get a certain percent -- or certain incentive. For the commercial custom program, that's for a larger project, more complicated projects, where customers may want to go deeper, have something specific to their facility. And so the program has been operating under the same incentives for awhile now. And so we have expanded the caps associated with that program in order to generate larger projects to get larger savings and to really incent the customers to be able to go deeper if they're able.

And, again, to get to 741 gigawatt-hours, the expansion of those caps helps us get there. So in order to achieve that level of savings -- we've never achieved that level before. We are doing things different than we have in the past in order to reach that target.

Q. When was Georgia Power's most recent commercial saturation study?

A. (Witness Phillips) I don't recall when the commercial -- the previous commercial saturation study was done. I believe we filed it as part of a data request. And so I don't recall that date.

We -- I do know that we just have recently conducted a new residential saturation study. And that has also been provided in a data request. And that was in response to the '22 IRP, which directed Georgia Power to update its residential saturation study.

Q. Is it fair to say that the commercial saturation study wasn't in the three-year cycle?

A. (Witness Phillips) We did not update the commercial saturation in the last years.

Q. Would you agree that it's important to examine where growth is occurring on the system and to target energy-efficiency measures there?

A. (Witness Phillips) When you say growth, could you be more specific what you're referring to?

Q. Load growth.

A. (Witness Phillips) Well, I think growth is an -- isn't a -- it's a variable that needs to be considered. As Dr. Beppler stated, in our modeling we model representative facilities, we model both residential and commercial facilities, when trying to calculate the potential savings.

And I think the potential TEAPOT study. One of the first steps in the TEAPOT study is the market characterization. So we do consider changes to the market. That's one of the first steps.

And then once we complete the market characterization, then we begin the measure characterization. So I think growth is considered. Inherently it's considered in the forecast, which is part of that market characterization and developing a baseline forecast for the potential study. So certainly growth is important and I think we capture that to some extent in our analysis.

A. (Witness Beppler) I will just add there, when we're talking about growth, we're often talking about new facilities, which are installing measures or equipment that is more efficient or is based on the latest building codes and standards. So there actually is more potential available in the existing market for customers who maybe don't have as new of equipment or whose buildings were built before some of the recent evolution in codes and standards.

A. (Witness Goff) That's right. At the end of the day, we want to go to where the potential is in the most cost-effective manner that we can for the benefit of our customers.

Q. Did y'all watch the panel two days ago?

First panel, but the first day?

A. (Witness Goff) Yes.

Q. They said that improvements and efficiencies, like in -- this isn't a quote. I'm paraphrasing. Improvements and efficiencies in, like, servers at a data center will just lead to more densely packed data centers. That if servers improve, they'll just add more.

Is it Georgia Power's position that there are no energy-efficiency gains to be gotten from data center customers?

A. (Witness Goff) No, I don't think that's the company's position. There are certain measures included in our commercial programs that I think would -- data centers could participate in.

But, in general, what we hear from the data centers in working with them, and I think this is what Panel 1 expressed, is the data centers are very efficient. And as they continue to get more efficient, then they're going to take that extra capacity to add more to their operations.

So I don't think that we're saying there's no efficiency. I think that -- to the extent that they can be more efficient, that's great. But, to your point, what we're hearing right now in the market is that that would be kind of taken up with additional usage on their side.

A. (Witness Beppler) Yeah. And it's --

VICE-CHAIRMAN ECHOLS: Ms. Goff, let me ask you --

MS. GOFF: Yes, sir.

VICE-CHAIRMAN ECHOLS: In the conversations, these are new buildings. So the SEER rating on the HVAC units that they're putting in, have you had -- are they putting ENERGY STAR units in?

Do you know; are they lower SEER, higher SEER?

Have you had any conversations about that?

MS. GOFF: I don't know the SEER specifically. I saw some metric -- and I wish I could remember what it was called.

But it was essentially a metric around the efficiency of their non-server usage. That has gotten dramatically more efficient over time in one of the presentations I saw.

So I can't equate that to a SEER rating for you, but they have shown -- I've been in a meeting where they've shown how they are getting more efficient with their non-server -- the parts of the facility that are not the servers.

VICE-CHAIRMAN ECHOLS: I went to the data center conference over here in Midtown. And they were -- there were a number of vendors there who were touting insulation, different energy-efficiency things for -- you know, for data centers, in terms of technology and efficiency. I don't know how many of them are doing it, but the vendors are paying the fee to get over there in front of them.

MR. PHILLIPS: And I think to Dr. Beppler's point -- and this point was also made by Panel 1. We are working closely with many of the new data centers, the ones that are selecting Georgia Power as their energy provider.

We have a number of existing data centers that we serve today and have served for a number of years. And data centers, being commercial customers, are eligible to participate in any one of our commericial energy-efficiency programs.

MS. GOFF: We've got hundreds of measures out there and then the custom program can be something custom to their facility.

DR. BEPPLER: And I just want to be clear, and if you'll indulge me a little bit. I know there were some economists in the room earlier. I'm not -- I can't see if they're still there.

But Jevons paradox was, I think, the Panel 1 term that you were referring to.

BY MR. SHERRIER:

Q.   Yeah.

A.   (Witness Beppler) It's also known as the rebound effect. So it's not that there isn't energy-efficiency potential for data centers, it's just that when you make and use more efficient it may lead to additional adoption and usage in that end-use.

And so what we're saying is that we don't anticipate that the -- just because the chips or the servers become more efficient that the overall usage of the computing power would decline. We think that those customers are likely to just add more because the use cases have expanded.

Q. Okay. So is it Georgia Power's position that there are no net energy efficiency gains to be gotten from data center customers?

A. (Witness Phillips) Well, I don't -- I don't think we've made that as a position. I don't think we've stated that.

A. (Witness Beppler) No. So the utilization of any one unit becomes more efficient and then that can lead to more units.

A. (Witness Goff) But at the end of the day, we're going to continue to monitor. We have a flexible process. And so as we learn more, we will incorporate that into all of our assumptions and continue to bring forth plans to this Commission based on the latest and greatest information.

Q. The TEAPOT study from this cycle found that

ENERGY STAR servers and data centers had the highest achievable potential savings by 2035; right?

A. (Witness Phillips) Can you refer to a specific page?

Q. Yes. It's page -- Table 2-12, maybe on page 4.

A. (Witness Phillips) Did you say page 4?

Q. Yeah. Unless it cut off. Table 2-12.

A. (Witness Phillips) Okay. I'm at 2-12.

Q. Yeah. And then it's line 16.

A. (Witness Phillips) Yes. So, Commissioners, Table 2-12 is the commericial top 20 measures in 2024 achievable potential savings. And what this table is comparing is the top 20 measures and the megawatt savings in the year 2024 versus the megawatt savings in 2025.

And in the year 2025, ENERGY STAR servers do have the largest potential, in terms of megawatt savings, in that year. And so we certainly see opportunity for data centers or servers specifically.

It's important to note that there are a number of servers across the state that aren't in data centers. They're in buildings, they're in facilities where they could qualify for these energy-efficiency programs if they upgrade.

And so this is specifically directed towards servers. Obviously data centers dealing with a concentration of servers would be a customer that could participate. And so with the future growth in data centers, we are reflecting that to some extent in the potential study in this table and in our results.

A. (Witness Goff) And I'll also point you to page 29, Appendix H, of our DSM application. This is the commercial custom measures.

Again, I don't have all the details on every single measure. There's hundreds of them. But there's very specific data center measures included in these commercial programs.

So to the extent a data center can be more efficient and take advantage of what we've offered here, that -- that's great. That is part of our program design.

Q. Am I reading the proposed plan right that the plan is for -- under the commercial prescriptive program for ENERGY STAR servers, that the estimate is 34 servers each year?

A. (Witness Goff) Where are you -- is that in the TEAPOT study?

Q. No.

A. (Witness Goff) Okay. Is it in -- I've got Appendix H open. Is it in Appendix H?

Q. I think it's in one of the document responses where you gave more information about the measures.

A. (Witness Goff) Okay. I don't have all the data requests here. I know there's a lot of work papers provided, too.

What I've got here is there are a list of measures in Appendix H, if that's something that you're asking about. I'm happy to look.

Q. Well, yeah. Could you tell me about the best practice measures for data centers?

What does that mean?

A. (Witness Goff) I don't know specifically. I'm very confident the design team and the implementation team would be able to tell you. But I do know that there are at least three measures on this page, both on the top and then three on the bottom, that have data centers associated with them.

So there are options out there, in addition to things like, you know, building shell and other HVAC. And, again, the custom program is great because if a customer has something that's specific to their facility, they can come to us with what those ideas are and work with the contractor to qualify for those incentives. So data centers are not the focus of our program design, but there are certainly options out there available for them if they want to participate.

Q. Thank you.

They can come to you. Do you go to them?

A. (Witness Goff) I'm sorry. Say it one more time.

Q. Do you -- you said they can come to you to participate. Do you go to them?

A. (Witness Goff) Heck, yeah. I mean, we work with our customers every day. We have people in the customer voice group, national accounts group, our region external, our sales group. I mean, we're with customers every single day.

Sorry. I get --

Q. I like --

A. (Witness Goff) Everybody is laughing.

COMMISSIONER PRIDEMORE: That's good. Heck, yeah.

MS. GOFF: I mean, yeah. Bring it on. Anything that we can --

COMMISSIONER PRIDEMORE: If you're not passionate about what you do, why do it?

MS. GOFF: Anything we can be more efficient for the benefit of our customers is something we should all be passionate about.

BY MR. SHERRIER:

Q. I'm going to shift over to you, Dr. Beppler, in a second.

But, Ms. Goff, you mentioned you've seen a presentation about an analysis of data. Was that -- tell me about that, please.

A. (Witness Goff) I wish I could remember the metric. It's been several months. I don't have the slides.

But it was something around -- there was the server efficiency and then there was the efficiency of the rest of the building. And after I'm going to probably be a little loose on details.

But what my takeaway was is that the data centers themselves -- that non-server efficiency had gotten markedly improved over time. And so happy to provide more details once I have them. I just don't have them here today.

Q. Yeah. I would love that.

Was it a Georgia Power study?

A. (Witness Goff) I honestly -- it's been probably -- it's been many months. So I don't remember the specifics.

Q. Okay. Yeah, I would love to follow up about that.

Shifting to demand response, but staying with data centers. So demand response I'm here meaning shaving peak loads on high-demand days. Georgia Power is projecting a need for nearly 9 gigawatts of new capacity by 2031. More than 80 percent of that is from data centers.

The previous panel testified that Georgia Power could ask to certify 8,500 megawatts of new resources the month after this IRP ends. I think that we can agree those are big numbers. So big that a reduction of just 10 percent of this new large load could save bill payers more than an entire new combined-cycle unit.

So I say that to say that I apologize in advance if this feels repetitive. But I want to be as clear as possible in the record about how y'all are approaching this moment.

Has Georgia Power Company asked existing data center customers whether they're willing to reduce their loads on high-demand days?

A. (Witness Beppler) As I think was previously stated, we're talking with our customers on a continuous basis. And I think we have a robust portfolio of programs that these customers can participate in. That includes our interruptible programs, as well as our new DER programs, which are designed specifically for customers who may be bringing backup generation, like many of these data center customers are.

In addition, many of these large customers are taking service through a rate which includes a dynamic price signal. So they are already receiving information about when the optimal time to reduce their usage is to benefit the system. Historically we have not seen these data centers be particularly price responsive, but certainly they have the ability to respond to those prices in realtime.

Q. You say: We are in conversation. Who approaches them to discuss RTP rates?

Who approaches them to discuss the demand-response programs that Georgia Power offers?

A. (Witness Beppler) So I'm not familiar with all of the specific conversations that are had. But as part of the contracting process, there's conversations with our customer choice, economic development team, our sales team, who are aware of these program options and can communicate about the benefits of participation or the incentive structures that are available through these specific rate options.

A. (Witness Goff) And, again, the DER programs are a great option for data centers, too. And that allows us to hopefully leverage assets that they may be using for resiliency to the benefit of the grid.

So there's a wide variety of things that data

centers can contribute and participate in that the company is already offering.

Q. Are any of you on the large-load governance team?

A. (Witness Goff) Yes. I am involved with several meetings associated with large-load customers. And there's a lot of governance that is taking place across the company. These are large customers and so large governance -- governance around large loads is important.

Q. I mean the specific large-load governance team that Witness Robinson referred to in his testimony.

A. (Witness Goff) No. I don't think any of us are involved with that one.

Q. Is anybody from your departments on the large-load governance team?

A. (Witness Goff) Not the one that he was describing. But, again, there's lots of -- there's lots of governance taking place across the company. We want to get this right. We all have an aligned incentive around making sure that we're planning the system appropriately to be able to deliver reliable and affordable electricity to our customers.

A. (Witness Beppler) Yeah. And I'll recall -- I think Witness Robinson testified in many of those

conversations with data centers -- I believe he said they're often looking for five 9s reliability. And so that is a paramount importance to them.

To the extent that they have the willingness or ability to participate in programs, we have options available for them. And we think that provides value, but we are certainly not mandating participation in the programs.

Q. I'm going to come back to a lot of things that y'all said, but I'm going to go through this list.

Does anybody from y'all's department talk to data centers in the pipeline about demand response?

A. (Witness Goff) People that we work with and -- I don't know that we talk to the data centers themselves.

Well, yeah. So we have been in conversations and/or groups that we work with about our DER programs specifically. So we're trying to get customers enrolled in those programs. There's a lot of benefits that can be had for the system through that participation. So, yes.

A. (Witness Beppler) I would agree, yes. We have been in conversation with data centers or the companies that are driving some of this data center group.

Q. When you talk about the demand response, are you talking about 2 percent, 5 percent, 50 percent of their load?

A. (Witness Beppler) I'm not sure I follow you.

Q. When you describe the options to them for demand response, do you talk through different percentages?

And, again, 10 percent of a 1,000 megawatts is a lot.

A. (Witness Beppler) So the structure of our existing demand response and DER programs enables flexibility in the amount of demand response that a customer would want to enroll in a program. So there's an option. They could enroll -- to use your numbers, 2 percent or 50 percent. The structures are designed to be flexible for their arrangements.

Q. Are you in discussions with committed customers -- committed being the Georgia Power term -- about whether those data center customers are willing to reduce their loads on high-demand days?

A. (Witness Beppler) I can't speak to specific conversations, but I think as we've -- we've stated a couple of times, there are a number of options available for them to participate in programs, as well as incentives through the underlying rates to encourage them to reduce their load during those high-demand periods.

A. (Witness Goff) So the company already has two

DER programs that are supply-side programs. The larger of those two is the one that would probably be most applicable to data centers. That's already been approved.

What we have included in this filing is a new, large customer-owned option that would be more akin to a demand-response option, as you're describing. Hopefully that will be approved. I know the Commission will consider it. And then that would be another option that we would work with data centers to see if that's something that they would like to participate in.

As Dr. Beppler mentioned, there's RTP, there's the curtailable load tariff that's already out there. There's a variety of options out there for our customers, whether they're a large load, small load. There's a lot -- there's a lot of options out there with the benefit of trying to create the most efficient grid that we can for the benefit of all customers.

Q. Have y'all put together, like, a data center package of: Here's your demand-side options?

A. (Witness Beppler) I don't know if there's a specific package, but there have been a number of proposals and we do have some decks that outline the specific program options available for customers to participate. Our sales and implementations teams are having regular conversations with customers utilizing those resources.

A. (Witness Goff) and hopefully this flexible framework is an economic-development tool. I mean, hopefully the fact that Georgia Power has such reliable service, but rates that are, you know, affordable for our customers, and a variety of options for data centers to participate in these type of programs, that should be something that's very attractive for the state.

Q. When new service is requested, what efforts does the company make to encourage the customer to build to higher efficiency standards than code?

A. (Witness Beppler) I don't think that we're in the practice of dictating to our customers what equipment they should be installing, but certainly we have programs available to them that might incentivize more efficient end-uses.

Q. Of the committed data centers, how many megawatts of load flexibility is Georgia Power planning for?

A. (Witness Beppler) Can you be more specific with load flexibility?

Q. How many demand-side option -- demand-response option megawatts from these data center customers is Georgia Power planning for?

A. (Witness Beppler) I don't believe that we have any for -- any megawatts on the demand-side ledger for new -- new projects or these new programs to this point. We do have some megawatts reflected for customers that are enrolled in our existing Demand Plus Energy Credit Program, which is one of our longest standing interruptible programs.

In addition, we do take into account the historical response of customers in developing the forecasts. And so to the extent we've seen customers respond to price signals through things like RTP, we would incorporate that in the forecast, as well.

A. (Witness Goff) And the structures there, the company has proactively brought programs forward to this Commission in order to have those flexibility options available for our customers. So we want these programs to be successful and hopefully create efficiency, again, for all customers.

Q. Me, too. Let's talk about those programs.

I want to look at the demand-side options that Georgia Power does give some capacity credit to now on the resource ledger.

Is that the Territorial Base Case versus Existing Capacity Cable?

A. (Witness Beppler) Can you point me to a specific reference?

Q. Technical Appendix II.

A. (Witness Goff) I've got Technical Appendix I.

A. (Witness Phillips) Do you have a copy?

Q. I might. It's very tiny numbers, though. This is a big spreadsheet.

I have 2023 and 2022, which I will give y'all in a moment, I suppose, but I don't have the current one.

Y'all okay?

A. (Witness Goff) Where is it?

Q. The Technical Appendix II, the Territorial Base Case versus for Existing Capacity.

Are you familiar with the resource ledger?

A. (Witness Beppler) Yes.

Q. It shows how much capacity Georgia Power is forecasting for specific demand-side options in part of it; right?

A. (Witness Beppler) Correct.

Q. Would it surprise you that Georgia Power's total forecasted capacity for demand-side options in this case is lower than what it was in 2023?

A. (Witness Beppler) Are you speaking to the program capacity or the planned capacity?

Q. Planned.

A. (Witness Beppler) Okay. Commissioners, it doesn't necessarily surprise me. I think, as we testified to yesterday, there was some megawatts included for the DER customer pilot that was approved.

Assuming that we would fully enroll that program, moving into this cycle we elected to remove those megawatts until we have specific customers contracted to participate in that program. So I think that's probably what's causing that planned megawatts to decline between vintages.

Q. We'll look at the demand plus energy credit and the realtime pricing DPEC in the RTP.

Is it fair to describe those two programs as large customer demand-response programs where you can get demand reductions in response to pricing? I believe you were kind of talking about this a moment ago.

A. (Witness Beppler) Yes. I think I clarified that DPEC is sort of your traditional demand response. RTP operates a little bit differently where it's not specific event-caused, Commissioners, but rather a provision of a continuous stream of price data that indicates what system costs are in any given hour.

Q. For DPEC, would it surprise you if the current resource ledger planned for less than 100 megawatts?

A. (Witness Beppler) I don't have the specific number here, but I -- that doesn't surprise me. As we go into each planning cycle, we look at the enrolled customers in these programs and then we do a continual best practices of evaluating the available response and how that aligns with our periods of system need or the areas in time where we're most likely to be reliability challenged and see how those megawatts of the customer load shape align with the system needs.

That enables us to provide an ELCC, effective load carrying capability, for those programs. And so that's updated each vintage, Commissioners, and can result in a little bit of difference between vintages in the actual number of megawatts that we reflect for planning capacity on the ledger for those programs.

A. (Witness Goff) And if you zoom out, I think, on page 9 of our testimony, lines 19 through 20, or, let's see, 18 through 20, it says: By 2028, our DSM portfolio -- now that includes things like DSM, DPEC, CDR, RTP, other things, that's 1,400 megawatts or approximately 8 percent of the current peak demand.

So, you know, that is a -- when you kind of zoom out and do a culmination of all the things that are available, that's the number that's available through our testimony.

Q. The DPEC capacity, though, is flat for the -- all 20 years. Do you not expect that program to get more savings over time?

A. (Witness Beppler) I'm sorry. Can you be a little more specific?

Q. On the resource -- on the resource ledger it's flat across for 20 years. It's the same savings as today.

A. (Witness Beppler) You mean the projections of future savings on the ledger --

Q. Yeah. Capacity.

A. -- are consistent through time? Yeah.

So, Commissioners, based on our best available information, we continue to reflect those savings out into the future. Because we anticipate that those customers who are currently enrolled will stay enrolled in the program.

To the extent new customers sign up for that program, or the customers who are on that program expand their operations over the amount of demand response they're committing to, we would update those numbers to reflect that.

As I mentioned, this is an annual process. So we're currently -- or we're constantly applying the best available information on the amount of the response available to inform the demand-side ledger.

Q. Will it be updated before July of this year?

A. (Witness Beppler) I -- I don't believe it will be before July. It's updated consistent with the annual IRP process. So each cycle, as we identify all of the supply-side resources, we do the same thing on the demand-side.

Q. I suspect based on those answers that it might be similar here. But on RTP, can you describe that kind of in simple terms with RTP and how it shows up as capacity?

A. (Witness Beppler) Sure. So I want to be clear. There is a component of RTP which is reflected as a reduction in the load forecast. That's sort of the normal RTP response.

What's captured in the ledger, Commissioners, is what we sometimes refer to as extreme response. But essentially that is a response that would be anticipated if those RTP prices got above the normal or typical threshold that we see for those costs. And so that is reflected separately as a demand-side option. It reflects larger response than you would anticipate when prices are higher.

Q. A lot of Georgia Power's retail sales are under the RTP tariff; right?

A. (Witness Beppler) That is correct. I believe the figure is roughly a third of Georgia Power's retail load is -- receives a dynamic price signal.

Q. Because that includes data centers. But do you expect data centers to also enroll in that tariff?

Have you seen them do that to date?

A. (Witness Beppler) I believe some data centers are being served through RTP or a dynamic rate, yes.

Q. So why is the RTP capacity credited in the resource ledger also flat for 20 years?

A. (Witness Beppler) Again, the ledger reflects our best available information. And historically we have not seen data center customers that we have today on the RTP rates be particularly price responsive. To the extent that in the future those responses materialize, we would update the megawatts that are reflected on the ledger to reflect that.

A. (Witness Goff) And as Mr. Valle pointed out in Panel 1, there's a constant evaluation of where our forecast is, where actuals are coming in. And so as Dr. Beppler described, flexible framework. And so as we learn more, all of that best information is incorporated into our assumptions.

Q. Is that why the -- the numbers for RTPs changed in between 2023 and now?

A. (Witness Beppler) I think part of that change also reflects that we lost a particularly price-responsive customer. Witness Valle could have spoken a little bit better to the specifics of that. But I do know that there was some -- some change in customer mix and one of those very price-responsive customers is no longer taking service.

Q. Thank you. That does explain that.

Would it take less than six years to change those numbers?

Like, could you increase the capacity of those in under six years if you got better price response signals out?

A. (Witness Phillips) When you say better price response signals, what do you mean by that?

Q. Of a third of the sales, it's, like, 100 megawatts is responding to the price.

A. (Witness Beppler) No, no, no. So clarification. As I mentioned before, that's just a portion of the price response. Some of it is captured in the forecast.

That is just the portion that is above the standard price deviation that we see currently in RTP. So it reflects those extremely high-priced scenarios where RTP prices would be above the traditional thresholds, or what we've seen historically. And so with those higher prices we would expect to see some additional response on top of that that is captured in the forecast.

A. (Witness Goff) And I think that's very consistent. Mr. Valle and Dr. Beppler can confirm, but I think these processes are very consistent with the processes that we've been employing for many years now.

Q. I think that's right. I think that things are changing in the short term is why I'm asking about this in such detail.

A. (Witness Goff) That's right. And, again, we are monitoring in the short term for the latest and greatest information to incorporate into our planning process.

Q. And the first panel said that there was a different nature to this load -- excuse me -- and that Georgia Power is talking to other utilities about best practices, how they're responding to data center requests.

What are -- are there other new programs in the works that aren't in the IRP yet?

A. (Witness Beppler) I think Section 10.5 specifically discusses that we're having ongoing conversations and trying to meet customer needs. So what we've put forward in this proposal is a new large customer owned resiliency option.

I think that is the only new large customer or DER or DR program, but we are continuing to look at best practices, available options, listen to the needs of our customers. And making sure that we're not only meeting the needs of those potential participating customers, but that by offering these programs we'll be able to deliver benefits to all customers, as well.

Q. Have you -- has Georgia Power considered requiring all new large loads to do some kind of demand response, given the scale of this?

A. (Witness Beppler) I'm not aware of any sort of mandate to participate. But we do think that there is value in having options available to these customers.

A. (Witness Goff) And, again, the programs we offer, they offer benefits to the participating customer and they offer benefits to all customers. And so we do have a suite of programs that are available for all of our customers, large customers and small customers.

Q. But what about temporal and spacial workload shifting? Have y'all -- have y'all worked with data centers about reducing demands through those ways?

A. (Witness Beppler) Again, I think many of these data centers already have those incentives through the rate that they are taking service under. They can reduce their operating costs by shifting their usage to lower-cost hours, which correspond to hours where it's more efficient and cheaper to operate the system.

Q. But it's not in the capacity plan yet?

A. (Witness Beppler) Again, as I've stated, we continue to update these based on the best available information. So some portion of that response is baked into the forecast. There's some additional response that's also captured on the resource ledger.

And as we see response change over time, be it through new customers added to the system or changing behavior of those customers, then we would reflect those changes in the resource ledger.

A. (Witness Goff) And I will say we are here to talk through the programs that we're offering. How the ultimate capacity plan and the supply-side plan comes together, that really is a Panel 1 topic.

Q. On the demand side, have you looked at maybe quicker interconnection times for large loads that are willing to do load flexibility?

A. (Witness Beppler) One of the advantages of the new program that we've introduced, the large customer owned resiliency program, is that it will be on the demand side as opposed to the colocation program which was previously approved.

The intent of that is to shorten the interconnection timeline. So we've heard discussion of FERC Order 2022, which mandated that cluster study process. That extended the timeline for supply-side resource interconnection.

This new program will provide faster interconnection timelines because it won't be subject to those same FERC-mandated interconnection processes.

Q. Turning to the distributed energy resource programs that y'all have mentioned -- and apologies to everybody. That is RAS, DRC, DCL, and DCO?

A. (Witness Beppler) Yes.

Q. None of them have any subscribers?

A. (Witness Beppler) Currently, no. As -- as we testified yesterday to some questions from staff, we are in a series of ongoing conversations with interested customers. So we have seen that customers are interested.

And we've continued to make progress in discussing sort of more specific details around contract language and equipment types and things of that nature. So there's momentum building and we see interest from our customers, but we don't have anyone enrolled to date.

A. (Witness Goff) Based on all the smirks, maybe it's the names of the programs. Maybe we need to update our acronyms.

Q. But, yeah. I don't know. I'm not a brand name person.

Are you considering other design changes, though, in addition to names?

A. (Witness Beppler) So we did request approval from the Commission in this proceeding for a change for the DER customer-owned program. So that's DCO, if we're following along in the acronym alphabet here.

And that is to extend the potential contracting duration from -- through 2031, as the language currently is written, to up to 15 years. And the intent of that change is to provide some more certainty and benefit to participating customers who are having to make the upfront investments in these resources and the interconnections to enable them to be used for the benefit of all customers, while also extending the duration of time that all customers are going to benefit from procuring that capacity at below avoided cost.

Q. Why aren't you recommending any changes to the other three?

A. (Witness Beppler) Because we continue to see customer interest in those and we've introduced a new program here, which sort of rounds out the portfolio. We think now we have a suite of programs that can meet all of these individual customer needs.

So customers are not a monolith. They have unique needs and preferences, as far as ownership type, payment structure, all of those things. And so we think having a portfolio of options available to them is likely to lead to the most success in enrolling customers.

Q. You mentioned that you're in discussions around DCL and DCO. Is it accurate to say that of the 11 customers you're in discussions with, none of them are greater than 50 megawatts?

A. (Witness Beppler) I don't recall specifically the megawatt numbers. But, subject to check, I'm willing to accept that.

Q. So is it fair to say that not -- no one in the large-load pipeline is in discussions about the four existing programs?

A. (Witness Beppler) I would not agree with that statement. As we testified to earlier, Commissioners, we're having conversations specifically with some of these large-load customers about the options available to them. We may not have made firm proposals to any individual site for those customers, but they are certainly aware of the options to participate.

The other thing I'll highlight is sort of beyond the specific customers in the pipeline. We're also engaging with these customers in a number of collaborative exercises. So one of those that I think was mentioned yesterday was an EPRI initiative called DCFlex. And so that is conversations between utilities and these large load or data center customers about how to best take advantage of any potential flexibility in their operations for the benefit of the system.

Q. If a large-load customer enrolled in one of these four programs -- or five, if the proposal gets approved?

A. (Witness Beppler) I think it would still be four programs. So DRC and RAS are sort of linked under the customer program, yeah.

A. (Witness Goff) And they each have different qualifications. So depending on loads, the size of the customer, they may or may not be eligible for all four.

Q. Let me try again. If a large-load customer, like a data center currently in the pipeline, enrolled in one of these programs, DER programs, could you see those capacity benefits in less than six years?

A. (Witness Beppler) Yes.

MR. SHERRIER: Thank you. I don't have any other questions. I appreciate the Panel's time.

CHAIRMAN SHAW: Do you need a break?

Let's try to go to 12:30.

Panel, do y'all need a break?

MS. GOFF: No.

DR. BEPPLER: Doing fine. Thank you.

CHAIRMAN SHAW: Mr. Jones, we'll go ahead and call the Solar Energy Industries Association, unless you would want to wait until after lunch?

How much time do you need?

I might have to bring somebody else up that can fill in this gap.

MR. JONES: Commissioner Shaw, I probably will take past 12:30. If you would like to call somebody else out of order, that would be fine with us.

CHAIRMAN SHAW: Mr. Moreland.

MR. MORELAND: I would go past 12:30 probably.

CHAIRMAN SHAW: Ms. Coyle.

MS. COYLE: I can do it in 10.

CHAIRMAN SHAW: All right.

UNKNOWN SPEAKER: Not the hero we deserve, but the one we need.

CHAIRMAN SHAW: Are you good with that, Liz?

MS. COYLE: I'm absolutely good with that. Thank you.

CROSS-EXAMINATION

BY MS. COYLE:

Q. I thought I would be saying good morning, but obviously here we are afternoon. Good afternoon. Good to see you all.

And I do just have just a few really clarifying questions for all this excellent cross that has already happened.

I wanted to start going back to where we started yesterday afternoon. Mr. -- there were a lot of -- there were a lot of numbers crossed -- sorry -- tossed around when -- the conversation with Mr. Collado. And I just want to clarify. And, again, there were some questions just recently by Mr. Sherrier.

Your expectation to achieve the 0.75 percent the 750 gigawatt-hours, would increase the current budget from roughly 94 million to 570 to 580 million.

Would that start in 2026?

A. (Witness Goff) Yes.

Q. And you put that yesterday -- you put that in the context of some supply-side spending comparisons. You compared -- and you had mentioned again this morning with Mr. Sherrier, you compared the amount of -- you said that since 2011, 27 -- 4,700 gigawatts of savings have been achieved.

Am -- am I correct that you compared that to plant -- one of unit, two --

A. (Witness Goff) So -- yeah. So coming into this I wanted to have an analogy of what is 4,700 gigawatt-hours of energy reduction compared to. And so I asked my friends in resource planning. And it's the Georgia Power share of what Vogtle Unit 2 produced last year. So that's the amount that we've achieved since 2011 to the benefit of customers.

Q. So one year of one level --

A. (Witness Goff) That's right.

Q. -- of unit in one of the older units?

A. (Witness Goff) Yes.

Q. Okay. But --

A. (Witness Goff) But significant.

Q. But significant. And so would you say that in that -- and so if you're looking at a budget next year of 570 million, could you put that in the context of what it would cost -- you know, as opposed to building another Plant Vogtle, for example, if you put it in the context of the potential cost of the entire supply-side program that's included in this IRP.

A. (Witness Goff) I can't do that. I don't have that information. I apologize.

Q. You couldn't -- so if you're -- okay. Maybe -- maybe one of the other -- if it's 570 -- you're estimating 570 to 80 million for -- for these programs starting in 2026.

You have no way of comparing that to the potential cost of the entire IRP system?

A. (Witness Goff) No. The only comparison I have is that currently our budgets are about 90 million. So the budgets to achieve .75 percent are five to six times what we are implementing today.

Q. But would you say that this -- this is the budget that's in -- the current one that's in the millions, looking ahead it's in the millions.

Wouldn't you say that previous supply-side budgets have been more in the billions range?

A. (Witness Goff) That's probably a better question for Panel 1. But, again, through these IRP processes, we bring forward the most economic proposals to the Commission to be able to reliably and affordably serve our customers across the state.

Q. In a cost-effective way for these programs you feel; that these --

A. (Witness Goff) The cost-effectiveness measures are included in what we file for the DSM programs.

Q. And I just wanted to -- again, follow up with some cross from Ms. Brown yesterday. You mentioned yesterday that you were looking to -- she asked you about the definition for LMI.

A. (Witness Goff) Yes.

Q. And you answered that you hadn't fully decided how you were going to define that, but you mentioned the possibility of trying to expand the program to increase eligibility and to potentially -- going up to 304 percent of federal poverty level; is that correct?

A. (Witness Goff) That's correct. That's specific to our EASE program and so --

Q. It's just to the EASE?

It's not to the other programs; just to EASE?

A. (Witness Goff) That's right. HopeWorks is a 501(c)(3) so we can't dictate to them what their income qualifications will be. But as we go through an RFP to select an implementer for EASE -- make sure I said that. HopeWorks is a 501(c)(3).

Did I say that correctly?

Q. Yeah. Right.

A. (Witness Goff) And then EASE is the one that we're working to expand the definition of that income eligibility.

Q. Okay. So it would be the Georgia Power EASE program only, not -- so HopeWorks would not -- what you define for the EASE program would not apply to HopeWorks?

A. (Witness Goff) No. Because they're a 501(c)(3), we can't dictate those eligibility requirements to them. So what we have proposed is the expansion to low to moderate income in our EASE program.

Q. Okay. And so in the -- so how will you -- what will your -- marketing, I guess, is the question.

How will you work to expand the program to serve those additional customers?

A. (Witness Goff) So we will go through an RFP to select an implementer for these programs. And the caps on EASE and HopeWorks are designed to be set at $5,000 per home. We are expanding the measures. So there's lists of all the measures are included in our filing.

So we've expanded the measures that are including -- that are included in those programs. And like I've mentioned, we expanded, as we've been discussing, the eligibility requirements for EASE itself.

Q. And how many more customers do you think you'd be able to serve?

A. (Witness Goff) It's like 17 times more homes than what we're implementing today.

Q. And then keeping in that vein, let's talk about EASE and I'll -- so the other new program that you have, including the pilot and I have a couple of questions about the CSS, PS -- I agree with Bob. We need a -- we need a better name.

A. (Witness Mallard) We're taking suggestions.

Q. EASE is such a nice name. So, you know, something -- it would be good to have a name so it's easier to call it.

But, you know, with -- when EASE started up when it was a new program three years ago, there was a real slow period of time to ramp it up. Obviously there were supplier issues back then, other things. You know, pipe -- you know, some related to the end of the pandemic.

But, you know, what are -- what plans for some of these other new programs -- because you've got several new programs in this filing -- to have -- ramp things up faster than you were able to do with the EASE program?

A. (Witness Goff) So in the DSM application there's one new program, the residential products program. And so we would go through a third-party RFP to select an implementer for that and then try to hit the ground running, sharing detailed plans with staff for input prior to going to market.

I don't know if there's other programs --

A. (Witness Mallard) Yeah. I can speak to the residential solar plus storage program. And as we've discussed, the plan is to use an implementation partner to roll that program out. And the expectation would be a partner that has some experience with these type of programs in other -- in other states and other jurisdictions. And so leveraging their experience will help us be able to roll out the program just as quickly as we can.

I'll make one more comment related to the LMI back to the Solar Plus Storage program. The conversation yesterday was related to what potentially could be an LMI limit. I just want to reiterate we want to make sure that we are making our program compatible with other sources of funding that potentially could be used, like the Solar for All, like maybe potentially corporate sponsorship. And so the development of any LMI parameters would be in consideration of what might be allowable or required by some of those other plans.

Q. Okay. Sure. And you actually anticipated one of my questions, which is that you do -- you do expect to coordinate with Solar for All?

A. (Witness Mallard) Yes.

Q. I'm assuming GEFA?

A. (Witness Goff) Yes.

Q. And what about some of the partners in the broader income-qualified space, including some of the discounts -- working with HopeWorks and Salvation Army and some of those other partners who are working directly with the LMI customers that you might be targeting?

A. (Witness Goff) Absolutely. The company, the target, we work collaboratively with GEFA, with community action agencies, with -- I mean, folks all across the state. We want these programs to be successful and we really want to benefit customers in the most need. So absolutely, yes.

Q. And then just looking at your testimony on page 40, the bottom lines of that question on that page, lines 20 to 26 -- and you talked some with Mr. Sherrier about this earlier. But this is where you're talking about the -- the potential --

A. (Witness Phillips) What page, Ms. Coyle?

Q. Page 40, lines 20 to 26.

You talked about, like, a check-in approach. That's the paragraph -- it looks like Mr. Beppler wants -- wants to answer that one. How do you -- how will you best identify opportunities to scale the program?

When -- you know, what are you looking for when you say, "You know, this is going so well," maybe a year and a half, two years into it. What's the mechanism by which you would do this check-in and potentially go from pilot to full program sooner than later?

A. (Witness Beppler) Yeah. I think one of those is if we reach the target that we have identified, in terms of enrolled megawatts for it, conditions of change substantially such that it would require an update.

So, you know, as we're implementing these programs, we -- as Witness Goff mentioned, we want them to be successful. So if there's changes in the industry, in the marketplace, in technology, that allow new opportunities, then we would certainly seek the feedback of the Commission on any updates.

Q. Okay. And I apologize. I meant Dr. Beppler I apologize.

A. (Witness Beppler) No worries.

Q. So continuing there, do you have -- and going back to the previous question, have you identified a target percentage that you want to be in that LMI category?

A. (Witness Beppler) We've not identified a specific target percentage or carve-out. You know, one of the things that we have been doing is working and having conversations with those other sources of funding to make sure that we can sort of identify opportunities for a collaboration there, such that if -- if they're installing solar through some of those other channels, then we could partner to, you know, encourage the adoption of storage resources alongside those -- those assets.

Q. So in making -- in doing that analysis, I'm wondering if -- while you're considering the possibility of scaling up, if some segments are performing better than others -- let's say, that the LMI segment is not performing as well as other customers -- would you take some additional steps to try to identify and address reasons for that -- that gap?

A. (Witness Beppler) Yes. I think part of the intent in proposing this pilot with two participation channels is that while we got a lot of robust feedback in the development, we know that, you know, we might not get everything right exactly out of the gate. And so we'll continue to learn and adapt from this implementation to inform future program design.

Q. And you could make changes realtime?

A. (Witness Beppler) I don't know if I want to commit specifically to realtime. But as we get new information, we continue to update our program designs, yes.

Q. Well, and going back to EASE and the early days of EASE, there did need to be some tweaks, you know, without necessarily even going back to the Commission.

Are you-all going to have the flexibility to -- I'm not saying you're not going to inform the Commission. I certainly assume you're going to inform the demand-side mandatory group like when I was in staff here.

But, you know, if you identify some real challenges, maybe it's in the marketing, you can take steps earlier in the process to try to correct those, like you did with EASE, is that right?

A. (Witness Beppler) Yes. I think what we've outlined here is -- is a framework. There are some details that we will still need to work through with the implementation partner that we select to go and implement these programs. So certainly as we come across any future barriers to implementation, we'll try and make adjustments or changes as necessary to make sure that these programs are successful.

MS. COYLE: Great. Thank you. No further questions.

Thank you. And I did it.

CHAIRMAN SHAW: Thank you, Ms. Coyle.

All right. Y'all, we're going to break. We're kind of -- got a long way to go. So we're going to break for -- for, let's say, 50 minutes and come back in at 1:20. And -- well, let's say 1:25. Let's try to get in at 1:25.

And to just give you a little info on what we're thinking, I think we're going to be going probably late tonight and I'm considering maybe -- and I'll finalize this when we come back from lunch. Maybe taking like a 30-minute, 45-minute break somewhere around 5:30, 6:00 so everybody can get a little snack, DoorDash if you need to, whatever. But we'll see you-all at 1:25.

(A recess was held.)

CHAIRMAN SHAW: Okay. Thanks to everybody. I hope everybody had a nice little quick lunch break. We'll get started again.

Before we do move on to the Panel, was there any housekeeping matters to take up at this time?

MS. WHITFIELD: Chair, I do have one housekeeping matter. I wanted to let you know that GIPL and Southface have worked with Georgia Power. Georgia Power has gone back to the independent evaluator of the pending All-Source RFP to discuss with them our request yesterday about information about the types of resources that are currently still in the All-Source RFP.

And Georgia Power and the independent evaluator and staff have all agreed to provide the megawatts by fuel type --

CHAIRMAN SHAW: Okay.

MS. WHITFIELD: -- of the resources that have -- that are still in the competitive tier of the All-Source RFP.

CHAIRMAN SHAW: Okay. Well, good. Thank y'all for all getting together on that.

MS. WHITFIELD: And we really appreciate their quick work on that.

CHAIRMAN SHAW: Yep. Thank y'all. Hopefully that same spirit will continue today.

All right. We'll pick up where we left off. Panel, I'll remind you that you're still under oath.

Georgia Solar Energy Industries Association.

MR. JONES: Chairman, Commissioners, Steven Jones, Matthew McKagen on behalf of the Georgia Solar Energy Industries Association.

CROSS-EXAMINATION

BY MR. JONES

Q. Hello, panel.

A. Hello.

Q. Again, my name is Steven Jones. Thank you for the opportunity to ask you some questions today.

A. (Witness Mallard) Sure.

Q. I will address my questions generally to the panel, but if somebody in particular -- maybe one person, I'm thinking -- wants to answer, let me know and feel free to answer.

Just some foundational questions here. The IRP, you would agree, recognizes the need for additional clean energy?

A. (Witness Mallard) The IRP recognizes the need for -- to procure a portfolio of resources to serve our customer needs. It's made up of dispatchable capacity resources, as well as energy-benefiting resources of -- that are renewable, yeah.

Q. Do you have a specific amount that you would like to achieve by a specific date?

A. (Witness Mallard) So we talked about the modeling a little bit yesterday. The Aurora model now does have the capability to select energy-benefiting resources to supplement the dispatchable capacity resources. The Aurora model indicates that an additional 4,000 megawatts by 2035, if approved at economical prices, would provide benefits for customers.

Q. And the Aurora model calls for that because it sees that renewables can be cost-effective and provide value to customers?

A. (Witness Mallard) That's right. Again, if procured at economical prices.

Q. As well as -- and you've talked about this a lot -- the sustainability goals of certain customers?

A. (Witness Mallard) Yeah. We're definitely informed by customer needs and procuring renewable resources allows us to offer subscriptions to those customers.

Q. And I know you've answered some questions about the RCBF framework and the replacement of the -- or the addition of the locational value of transmission --

A (Witness Mallard) Uh-huh.

Q -- or distributed resources; is that correct?

A. (Witness Mallard) Yeah. It's the -- it's a change in the avoided transmission component that we're going to apply as part of the evaluation of distributed generation RFP resources.

Q. And you answered some questions previously in the cross-examination about how that locational value was determined. So I won't go back into that.

But, generally, that recognizes that what -- that generation as close to load as possible is important; correct?

A. (Witness Mallard) Yeah. Placing generation where it is most valuable on the system due to proximity of load or due to existing load flows and grid infrastructure, all of those come into play as part of that evaluation.

Q. Where do you see concentrations of load on your system?

A. (Witness Mallard) Generally in and around Metro Atlanta and North Georgia.

Q. Where do you see concentrations of

large-scale utility solar in Georgia?

A. (Witness Mallard) Generally South Georgia, more specifically Southwest Georgia.

Q. And why is that?

A. (Witness Mallard) Solar has -- has located in Southwest Georgia and South Georgia in general because of the characteristics of the land. It's generally flat. It's generally easy to -- to turn into solar -- solar facilities.

CHAIRMAN SHAW: Just don't say we're cheap.

MR. MALLARD: I won't say -- don't -- I wouldn't do that.

And then, traditionally, access to headroom on the transmission system. What's changed a little bit now is focus on land use and a tightening of that headroom to access to the transmission system.

BY MR. JONES

Q. So would you say, as a general rule of thumb, the -- as we decrease the size of the solar system, it's easier to get it closer to load?

A. (Witness Mallard) I'd say as you decrease the size, it's easier to find parcels of land where you can -- where you can place the solar without -- without incurring additional cost or mitigations. You could still -- a

small facility could still be placed in a location that is not advantageous.

A. (Witness Beppler) But I -- I will just add that as you decrease the size, you also lose some of the economies of scale that benefit the -- the costs of those resources.

Q. Which is one of the great reasons why this Commission's directed RFPs, right, is because you then have companies bidding projects in that ensure that there is a value provided to customers; correct?

A. (Witness Mallard) Yes. Correct.

Q. And the Renewable Integration Study, to that end, recognizes that the company and the system can accept significant increases in solar penetration while maintaining reliability; is that right?

A. (Witness Mallard) That's true.

Q. And part of that is the integration of storage; correct?

A. (Witness Mallard) That's correct.

Q. But storage doesn't always have to be paired with solar; right?

A. (Witness Mallard) No, no. It doesn't have to be paired with solar. There are some benefits from colocated storage, but stand-alone storage placed on the system also can offer those benefits.

Q. What are those benefits?

A. (Witness Mallard) The ability to have dispatchable capacity that can -- that could be dispatched to meet the generation needs of the system.

Q. And reduces curtailment?

A. (Witness Mallard) It -- it could. It depends on the relationship of the amount of storage and the amount of solar on the system, and also the location of both. Additional storage could have the -- could offer reduced curtailments of solar on the system.

Q. Would you say as storage becomes more prevalent in solar systems that the company is learning lessons?

A. (Witness Mallard) Yes. We learn lessons every -- every procurement, every cycle, every -- every facility that interconnects to the system.

Q. Every IRP the company learns lessons; right?

A. (Witness Mallard) Yes.

Q. And developers learn lessons; right?

A. (Witness Mallard) That's true.

Q. So with every IRP, with every RFP, with every iteration, we're taking incremental steps forward; right?

A (Witness Mallard) I believe that's true.

Q. And that's an important process; right?

A. (Witness Mallard) That's the fundamental part of the renewable success that we've had in this state is we continue to try to improve our procurements, to make them the most beneficial for the customers that we serve and make sure that the procurements work for all the stakeholders involved.

Q. Have you seen -- has the company seen more storage paired with utility-scale solar or with distributed solar?

A. (Witness Mallard) In the distributed RFPs heretofore, they've been solar only. There has been no procurement of storage through DG RFPs. We see storage installed at customer sites, at customer locations, but there has not been storage -- there has not been the ability for storage to be paired with solar through the DG procurements.

Q. And any other type of resource procurement is -- does the company have any PPAs for DG solar paired with storage?

A. (Witness Mallard) Other than -- no. I don't think there's any PPAs that are connected at distribution voltage that are paired -- solar PPAs that are paired with storage.

Q. So going back to the importance of learning lessons, there's still a lot to learn about pairing batteries with DG solar; right?

A. (Witness Mallard) Yes.

Q. Do you think it would be productive to have a pilot program for solely DG solar so that the company could learn lessons from that?

A. (Witness Mallard) No. I wouldn't propose that at this time. I think what we proposed to add storage to are successful DG RFPs will offer the opportunity to bring those valuable storage resources onto the system and be able to learn from those types of interconnections and procurements.

Q. So there wouldn't be value in isolating storage and solar in a separate pilot so you can study that independently from other solar resources that might not be paired with storage?

A. (Witness Mallard) Theoretically there could be, but that's not what we proposed.

Q. Okay. But, theoretically, there could be benefits to that -- such a pilot?

What things could you learn from such a pilot?

A. (Witness Mallard) Just the -- some of the basics that we just talked about. The nature of the interconnection, the contractual requirements, the ability of the market to actually deliver on these resources.

Some of the feedback we've gotten from the marketplace is that storage can be hard to come by for -- especially for small installations. And so those are among many of the learnings that we would -- we expect to have and expect to get through this proposed modification to the DG RFP to add storage.

Q. So through the DG RFP or a separate pilot, you would learn things such as how those systems operate with flexibility; correct?

A. (Witness Mallard) Sure. How the systems can operate and how the company can dispatch them and what their response is like, what that value is offered to the system. That is one of the learnings we expect to get through the -- through the DG RFP.

Q. We can sum that up as flexibility and control; right?

A. (Witness Mallard) Sure.

Q. I'd like to ask some questions now about your -- the company's existing renewable programs and RFPs. Let's start with the customer-sided solar-plus-storage program.

That arose out of the 2023 IRP Update; right?

A. (Witness Mallard) That's correct, yes.

Q. And you've had a number of questions about the specifics of the program and those thresholds. I won't rehash those. I do want, if you could, though, go back and give me an overview of the pricing options because there are two different buckets in that program; right?

And so help me understand the difference between the pricing in the two buckets.

A. (Witness Beppler) Sure. So, Commissioners, the two buckets, as counselor referred to it, are channels for participation. One is the company-directed. That's where there will be a large up-front incentive of $750 per kW for participants who agree for a 10-year contract for utility control over those assets.

In the customer-directed channel, there is an annual enrollment of $15 per kW up front, and then an ongoing pay-for-performance incentive of $1.50 per kWh during utility-called events.

Now, let me also say there is a particular incentive for the LMI and MUSH segments that we discussed a little bit. So in the company-directed option, that up-front incentive for LMI and MUSH customers would be $1,000 per kW. And in the customer-directed option, that annual enrollment incentive would be $45 per kW.

Q. So in the company-directed model, there's no perform-based incentive; it's just that up-front payment?

A. (Witness Beppler) That's correct.

A. (Witness Goff) And that's because the utility -- the company would be directing the use of that battery during that time.

Q. But in either -- in both buckets, or in both what you call participation --

A. (Witness Beppler) Channels, pathways.

Q. Pathways, okay. As long as we're on the same page. If -- with the ongoing performance incentive, the capacity values decrease to 75 percent; correct?

A. (Witness Beppler) In both models the incentive was determined using that shared savings mechanism where 75 percent of the projected avoided costs are reflected in the incentive to participating customers.

Q. So you're not paying full avoided costs for the capacity of the batteries?

A. (Witness Beppler) That's correct. And the design there is to ensure that nonparticipating customers, those who might not be able -- or eligible to participate for one reason or another are still deriving value and benefit from the company offering this program.

Q. But in the performance incentive, that 15kW -- $15 per kW, that's an up-front, one-time payment?

A. (Witness Beppler) No. That would be an annual enrollment incentive.

Q. So it seems like this program recognizes that there's certainly capacity value for battery storage;

correct?

A. (Witness Beppler) Yes. That's fair.

Q. But the company thinks that that has to be discounted from the avoided cost?

A. (Witness Beppler) The discount, as I just described, is to ensure that there's benefits that accrued in nonparticipating customers, as well. And it takes into account that there's additional costs associated with implementation and administration of these programs.

Ultimately, we want them to be cost-effective as a whole. And so the benefits need to exceed the total cost not just of the incentives, but also the implementation and program administration costs.

A. (Witness Mallard) I'll just contrast that to how we procure it through competitive RFPs where we cover a lot of the administrative costs of the program through bid fees, winner's fees, other payments for the interconnection guidance and other things like that.

This program is going to rely on that discount of the total capacity value to cover some of the costs of administering the program. Again, trying to make sure we're recovering the cost from the cost causers.

Q. Has the company done calculations to ensure that the 25 percent will only cover program costs to the administration?

A. (Witness Beppler) No. I don't think it's specific to just covering those costs. Like -- like we've said a couple of times, the intent is that benefits accrue not just to participating customers, but also to all customers from offering these programs.

Q. So other resources that are paid at avoided cost is -- is there a discount on that avoided cost for administration of those resources?

A. (Witness Beppler) I'm not sure I follow the question.

Q. So if -- if I have a resource, let's just say it's a QF or something else, is there -- it's paid avoided cost, is there payment discounted for administration?

A (Witness Beppler) No. And those are fundamentally different structures. I think this shared savings approach is consistent across our suite of customer programs. So we see that in the DER customer programs. There's similar mechanisms with other certified DSM programs. But QFs and other structures that Witness Mallard can speak more to are a very different structure.

A. (Witness Mallard) Yeah. And we -- we do collect administrative costs from QFs. QFs are going to pay monthly administrative fees, monthly metering fees. Proxy QFs that are procured through capacity solicitations pay similar fees -- similar bid fees and winner's fees that we collect from other RFP participants. So just a difference in the mechanism of covering the administrative costs for these programs.

A. (Witness Beppler) And, Commissioners, I'll just highlight, in the design of these incentives, we did do some benchmarking across peer utilities. We think these are competitive incentives to encourage adoption. Those incentive levels should enable the company to revolver roughly a third of the up-front costs of these storage assets.

So we think that's a sufficient incentive to help move the market and motivate additional adoption of these technologies.

Q. Is this -- this pilot's really about addressing system peaks; right?

You dispatch the batteries to reduce peak?

A. (Witness Beppler) I think that is one of the primary use cases, yes.

Q. What are the other use cases?

A. (Witness Beppler) I think as we continue to get familiar with these resources, there's -- there's other value stacks that we can explore, as far as ancillary services and -- and reserves and things of that nature.

Being able to unlock some of those value streams is predicated on having control of these assets. And so Witness Robinson in the previous Panel talked about the investment in utility-centric DERMS. And that's one of the technology platforms that will enable us to potentially unlock some of those future value streams.

A. (Witness Mallard) And one other value stream is the value that accrues to the host customer through resiliency. And so customers that want to host batteries at their site likely also are driven by a resiliency need.

A battery is still a premium resource. A customer-sided battery is still a premium resource. Customers who are interested in their own resiliency needs, what this program offers is the ability to get more value. Not just have the battery in reserve for the few hours a year when there may be a power outage, but to be able -- for the company to extract that value, share it with other customers, and reduce the total cost to participate by those customers.

Q. In terms of resiliency, in both buckets or both opportunities or channels, whatever we're calling them, customers would experience that resiliency benefit?

A. (Witness Beppler) Yes.

Q. In terms of when you're calling those batteries for use, in the customer-directed they had the option to opt out. But in the company-directed, they

would not have the option to opt out; correct?
A. (Witness Beppler) That's correct.
Q. Do you think the company is fairly good at being able to predict when those peaks are that they'll want to call on those resources?
A. (Witness Beppler) Yes. I -- I do think we will continue to get the best information available. So we do have currently approved with our DERMs capability the option for visibility and predictability. So those will help understand when the peaks are occurring on the system.
One of the challenges in the customer-directed model -- and we spoke a little bit yesterday about the ELCC associated with that -- is that it requires 24-hour advanced notice or maybe in an emergency situation, 75.
So the requirements to give customers advanced notification, there could be some variation in when the exact peak occurs. But generally, yes, the company is good at understanding and predicting when those peaks are going to occur.
Q. And really this whole program is about getting resources closer to load; right?
Resources that you can dispatch?
A. (Witness Beppler) I think the intent of the

program is to unlock additional value associated with dispatchable resources and encourage those to be used in a manner that aligns participating customer incentives with the benefits to all customers.

Q. You think --

A. (Witness Goff) Participating customers get a benefit and then all other customers get the benefit of procuring that capacity for less than we otherwise would.

Q. So do you think -- let's drill down on that for a second actually.

So you're going to be able to procure energy at less than you otherwise would. So it's less than what your avoided cost would be?

A. (Witness Beppler) Correction. Sorry. I didn't mean to interrupt you. But you said energy and Witness Goff said capacity. I think there's an important distinction there.

Q. Please elaborate.

A. (Witness Beppler) The batteries themselves are based on avoided capacity values. So that's really the dispatchable nature of those resources.

Q. Do you think you'd be able to predict those peak or those call events within 24 hours in advance?

A. (Witness Beppler) With -- with a reasonable degree of accuracy, yes.

Q. Two days in advance?

A. Again, this is not my area of expertise. I think -- but we do have realtime operations who are constantly monitoring and forecasting the -- the needs of the system. Obviously there can be events that change those needs that might happen very quickly. And that is the value of these dispatchable resources is to react in near realtime such that if you have changes in either generation resource availability, a cloud comes over and a lot of solar drops off the system, or loads suddenly increase because you have a cold winter morning, you need the ability to operate these things in a dispatchable nature to provide that full value.

A. (Witness Goff) And as a data point, we do offer notification for existing thermostat DR program. So it's typically 24 to 48-hour notice there.

Q. So there will be realtime communication between the company and those resources?

A. (Witness Beppler) Yes. Through an implementation partner and a grid-edge DERMS platform, as it's sometimes described.

So Witness Goff mentioned our existing residential DR program. Through that we use the grid-edge DERMS to communicate with all of those potentially thousands of individual devices. In a company-directed

channel, we anticipate that communication being very near realtime.

In the customer-directed channel, the individual communications will be more sporadic and have maybe some slightly advanced notice required. And that's reflected in the differing incentive calculations that we talked through yesterday.

Q. And that DERMS contractor, that program, the OS, that's a new program; correct?

A. (Witness Beppler) Can you -- can you specify which DERMS --

Q. Recently acquired.

A. (Witness Beppler) You're -- you're referring to the utility-centric DERMS?

Q. Correct.

A. (Witness Beppler) Yes. That is currently in the implementation phase. So it was select- -- the vendor was selected recently and now it's going into implementation.

Q. Would that be the same that's used -- would that be the same system that's used to dispatch batteries attached to solar?

A. (Witness Beppler) Depending on the scale of those resources. So if you're dealing with a customer program like -- like the pilot that we're describing where

you have potentially thousands of very small-scale resources, you might have an additional grid-edge DERMS, which plugs into that larger utility-centric DERMS system, which is communicating across a variety of asset classes and channels.

If you're talking about more of the DG-sided or scale solar-plus-storage systems, those might plug directly into your grid-centric DERMS.

Q. So it's -- the holistic idea here is then that there's significant opportunities for the company to learn about deployed batteries, either stand-alone or paired with solar; correct?

A. (Witness Beppler) Yes. The intent of this pilot is to gain learnings about the technology, as well as the customer behavior when dealing with these colocated assets.

Q. In the company-directed model, is there an outer limit on how many events the company could call?

A. (Witness Beppler) There's not. In fact, we envision that there may be up to daily discharge that can be good for the health of the batteries, but also helps additional benefits accrue to both participating and nonparticipating customers.

Q. If you're in the -- but if I've got a battery, right, and it's -- and the company is calling on it and I don't know when it's going to be called, as a customer, then I don't have the certainty of knowing how much I can rely on that battery or when because the company could call it when I may need it; right?

A. (Witness Beppler) Well, we have committed to reserving 20 percent of the battery capacity for participating customer use. So, in other words, we would never discharge the battery below that 20 percent threshold to ensure that there's always some resiliency benefit available for our customers.

Q. But there's a cost to the customer each time it's discharged then; correct?

A. (Witness Beppler) I would disagree.

Where is the cost?

Q. The customer is losing the ability to utilize their battery should the company direct that it be used?

A. (Witness Beppler) The customer received a 750- or $1,000-per-kW incentive to participate in the program. And part of that contractual relationship is that that benefit was provided to the participating customer in exchange for the use of that battery.

A. (Witness Mallard) Let's contrast the two channels again because I want to make sure we're not -- we're not mixing. The company-directed gets the larger up-front incentive. The company gets exclusive dispatch rights down to 20 percent. It will always -- never go below 20 percent. That resource can be used in times of grid outage for resiliency for the customer.

But if that value proposition doesn't match a customer's needs, then the customer-directed option exists. Under that option, a lower up-front incentive, but the dispatch of the battery is in the control of the customer.

The company will send the dispatch signal. The customer can opt out. And so if a customer envisions a need for whatever that is for the battery, then the customer would simply opt out. It's pay for performance. So if they discharge, they'll get the credit. If they don't, they won't. And then they can use the battery for themselves. So that's the -- sort of the purpose of having both of the participation channels.

Q. Absolutely. And I understand. But what I hear is that with the customer-directed, it's a lot easier for the customer to determine the value of that system to them as opposed to the company-directed. Because with the company-directed, they have no way of knowing up-front when they're analyzing that value proposition of how often it's going to be called.

A. (Witness Mallard) I don't think that the customer would be counting on using the battery for anything, other than resiliency in a grid outage circumstance. A battery is different even from a thermostat program or others.

There's not a lot of sensible difference for a customer if the battery is being discharged or not. Their electrical loads are met by a combination of grid power, solar power, and the battery power. And so if the battery is called to dispatch, I would -- I would postulate that most customers are not even going to know that -- they're not even going to know that it's being discharged. They're not going to notice any loss in value from the battery being discharged.

Q. Unless there's an outage immediately after the call event?

A. (Witness Mallard) If there's an outage immediately after the call, again, the battery wouldn't have been discharged below 20 percent. They can at least count on that amount of storage remaining.

Q. So all -- so in the company-directed, as a customer all I can really count on is that 20 percent because I don't know if I am ever going to have anything above that in the event of an outage?

A. (Witness Beppler) Just because the lower threshold is 20 percent doesn't mean that the battery will only have 20 percent state of charge at all times. There is going to be wide portions of time between those company discharge events where the battery will likely be much closer to full capacity.

And, Commissioners, I want to remind you, this was a -- an option that was recommended in both previous intervenor testimony, as well as in feedback that we got from the collaboration sessions here at the Commission. There's a number of other utilities who are operating a similar model that's been successful and has had very high customer satisfaction rates.

So, again, it's an option available to customers. If it doesn't meet the needs of a specific customer, there are other participation options available for them.

Q. Understood. So when you're -- when the company is looking at these two options, and from a planning perspective, how are you going to treat the different participation channels differently from a resource dispatch perspective?

A. (Witness Beppler) Sure. So I think as I mentioned a little bit yesterday, we envision the customer-directed model looking more similar to the demand response programs where it's discreet event calls. The company-directed model will look more similar to utility-scale battery assets, in terms of the operation

and then the planning megawatts that are reflected for those assets.

A. (Witness Goff) But both will be reflected on the company's resource ledger to reduce what we would otherwise be planning for to the benefit of all customers.

Q. Let's switch gears. Let's talk about the Customer-Connected Solar Program. That was 25 megawatts out of the 2019 IRP?

A. (Witness Mallard) That's right.

Q. And you've got one customer on that program?

A. (Witness Mallard) One customer, two phases of installation. A megawatt and a half or so at that location.

Q. And this IRP seeks to expand that program; right?

A. (Witness Mallard) We want to expand the program. We want to do a couple of -- probably most important things, add the opportunity for customers to install battery storage for a lot of the same reasons that we just talked about. Also expand the sizing up to 6 megawatts.

A couple other smaller improvements, including not allowing new customers to participate. Currently it has to be an existing customer where the company has the ability to have -- to look at the

customer's usage.

So we feel like if we can make some of these changes, it will make this program more attractive to customers and another option for larger customers who want to host solar and storage at their facility.

Q. So out of the 25 megawatts, how many megawatts remain unallocated?

A. (Witness Mallard) Twenty-three and a half, give or take.

Q. When we're looking at solar across the system, you would agree that residential or rooftop is different than utility-scale?

A. (Witness Mallard) The panels themselves are -- are the same. The way photovoltaic energy is converted from sunlight into electricity works the same. The nature of the installations, their efficiency, how they're -- how the energy gets to the system, those things are different, depending on the type of installation.

Q. So we can -- can we break -- in terms of categories, we can look at residential solar, right, as one bucket?

A. (Witness Mallard) Uh-huh.

Q. Could we look at utility-scale as another?

A. (Witness Mallard) Sure, sure. I might even -- I might even define them by interconnection. A utility-scale interconnection is transmission generally. A DG project is distribution system interconnected. And then, further, we could break it down to customer-sided, which you might even divide into residential or commercial industrial.

A. (Witness Beppler) And further into behind-the-meter or in-front-of-the-meter.

Q. And they all have different attributes that you've got to plan for; right?

A. (Witness Mallard) They all provide -- they all provide solar energy to the system. Again, how it gets to the system, how much we can count on it, what the contribution is to avoided cost, avoided energy and capacity costs are different depending on the -- depending on the type of installation, but also the type of contract that the company has with the generator.

Q. In the IRP at page 102, I read that only 17 percent of customer-sided solar is paired with storage?

A. (Witness Mallard) Let me rephrase that. We've got 17 percent of our solar installations that have storage now. I think that's a pretty good number.

Q. Fair enough. And I'm just trying to get metrics here.

What percentage of utility-scale is paired with storage?

A. (Witness Mallard) I don't -- I'm not going to have that information in front of me.
Q. Would you mind getting that information and getting back to me with it?
A. (Witness Mallard) Sure.
Q. Make a hearing request for it? Thank you.
A. (Witness Mallard) Sure.
Q. And what about stand-alone DG; do you know what percentage of that is paired with storage?
A. (Witness Mallard) Stand-alone DG, again, currently those are solar-only procurements. There's no storage that's been included. That's one of the -- the basis of the change that we're proposing is to allow storage with DG facilities going forward.
Q. And what about customer-sided?
A. (Witness Mallard) Yeah. The 17 percent is the most recent number I have. I don't know that I could convert that into a megawatts or a number -- a number of customers. But we are seeing growing interest in customers installing storage along with solar at their -- at their sites.
Q. Let's talk about utility-scale RFPs for a minute. You're rolling unallocated or unfulfilled megawatts from the 2022-2023 utility-scale RFP forward?
A. (Witness Mallard) The unprocured megawatts

from 2022-2023 rolled forward into the CARES 2023 RFP target, which was 2,875 megawatts.

Q. But what about the 2023-2024 utility-scale RFP; were there any unallocated or unfulfilled megawatts in that RFP?

A. (Witness Mallard) Make sure we're talking about the right ones now. We're talking about CRSP 1, CRSP 2, and then now CARES is the one that's currently going. So CRSP 1 was seeking 1,030, procured 970.

No. Seeking 1,000, procured 970. 1,030 rolled forward. The 1,030, no resources were procured as part of that RFP.

Those 1,030 megawatts were rolled forward into the current CARES RFP. And that's part of why that's such a large target at 2,875 megawatts.

Q. If there are unfulfilled megawatts in CARES, will the company roll those forward?

A. (Witness Mallard) Traditionally that's been the Commission's decision. I would say that decision is most effectively made at the time that the RFP is issued, given all the information that we could gather at that time.

Q. If there are -- and the company's got RFPs -- or it's got procurements of solar that it's seeking in this IRP; correct?

A. (Witness Mallard) Correct.

Q. If there are unfulfilled megawatts from those RFPs, will the company ask to roll those forward?

A. (Witness Mallard) I think -- I think, again, that would be past precedent and the expectation. The exact nature of their request and how those would be allocated would be most efficiently made at the time of the RFP, taking into account the current conditions.

Q. Are there unfilled megawatts from DG RFPs that the company previously issued?

A. (Witness Mallard) Yes.

Q. Can you tell me more about those?

A. (Witness Mallard) Probably not quite as well as I could recite the utility-scale, but I can say DG RFPs out of the 2016 cycle procured just under 90 megawatts when the target was 150. So some megawatts rolled forward into the 2022 cycle.

Again, about 85 megawatts procured then. So we issued the 2023 DG RFP with a target that was 100 megawatts, plus the rollover. That RFP procured 42-ish megawatts. Those additional megawatts rolled forward. And the current RFP we're seeking in the neighborhood of 250 megawatts.

So in the DG, that -- again, without the specifics of the exact amounts, the unused megawatts have rolled over and are -- currently were part of the target of the ongoing 2024 DG RFP.

Q. And will those unfulfilled megawatts in that RFP roll forward to future RFPs?

A. (Witness Mallard) I think that's a decision best made at the time with all the information that the company and the staff has in front of them. Past Commission precedent has been that unfilled megawatts be rolled forward.

Q. And the IRP recognizes that renewables are important and that a significant portion -- a significant addition of renewables to the system is -- is possible and needed; correct?

A. (Witness Mallard) Yes. That's -- that's what is the basis behind the case. We want -- we need to add more renewables to the system. They can provide benefits to all customers, subscription options for interested customers if procured at economical prices.

Q. And you previously testified that DG has a locational benefit?

A. (Witness Mallard) So, yes. New this time in the DG RFP is the company is applying the locational value differentiation as part of the transmission deferment portion of the RCB framework.

A. (Witness Beppler) And I just want to clarify.

It could be a benefit or a cost, depending on the specific zone that that DG facility is interconnecting in.

Q. Right. But given -- and the RF- -- and there's now a locational tool for selection of solar sites; correct?

A. (Witness Mallard) Help -- help me a little bit more.

Q. There's a locational map that Georgia Power has made available to help siting of distributed resources; correct?

A. (Witness Mallard) Yes. So -- yes. So for DG, there's the hosting capacity tool that provides a map showing Georgia Power's distribution facilities, provides guidance to developers and potential bidders as to which circuits provide the best location to site DG facilities.

Q. With all that, with the updates to the -- with the updates to the RCBF framework, with the siting methodology, with the -- with the IRP's recognition that additional renewable resources are important, with the resource -- with the -- I'm sorry.

With the system study that recognizes additional resources could be added to the system, it naturally makes sense that we should roll forward any unfulfilled megawatts -- any unfulfilled megawatts from prior DG RFPs on a go-forward basis; correct?

A. (Witness Mallard) I can't commit to that. What I can say is distributed generation is valuable to the system. Procurement sizes and targets are really important to make sure that we have successful RFPs. And so it would be up to the Commission to decide the disposition of unfilled megawatts. Again, historically, those unfilled megawatts have been rolled forward per order of the Commission.

Q. Utility-scale -- the utility-scale RFP proposed in this IRP has flexible required commercial operation dates; correct?

A. (Witness Mallard) Yes. That's what we proposed.

Q. The DG RFP has targeted commercial operation dates of '27, '28, and '29?

A. (Witness Mallard) That's right.

Q. Why does the DG RFP not have similar flexible commercial operation dates?

A. (Witness Mallard) Actually, that three-year window is -- is sort of a flexible window. That's -- that's more potential COD dates than what the company has offered before. There's --

Q. I'm sorry. Go ahead.

A. (Witness Mallard) There -- there's less uncertainty around interconnection to the DG system. And so we have not experienced the same potential limitations around interconnection timeline and maybe a misalignment and the time you can build a solar facility and the time it might take to build the interconnection facilities. That's more of a transmission issue than a DG issue. And so there's -- there's not really any -- not really any problem to solve on the DG side that a flexible COD would allow.

Q. You view this then as an enhancement or an adaptation in this IRP over prior -- over -- this RFP over prior RFPs?

A. (Witness Mallard) The RFP in general or one of the particular components?

Q. The three-year window for the commercial operation date?

A (Witness Mallard) Yes.

Q -- that's an adaptation or --

A. (Witness Mallard) Yes.

Q. -- an enhancement, if you will, over priors?

A. (Witness Mallard) Yes, it is.

Q. And does the IRP recognize that to -- for the system to realize the benefits that distributed generation and renewables in general can provide, that RFPs need to be flexible and need to adapt?

A. (Witness Mallard) That's the whole theme of our IRP enhancements that we're proposing, yes, sir.

Q. And that goes back to what we talked about earlier about learning lessons with each IRP and each RFP; right?

A. (Witness Mallard) That's right.

Q. What are some of those enhancements in this RFP.

A. (Witness Mallard) For the DG RFP?

Q. Yes, sir.

A. (Witness Mallard) Yeah. So I would say the primary enhancement on the DG side is the addition of battery storage. And so as we've already talked about, the ability to add dispatchable capacity colocated with solar can add additional value to the system. We think that's a real game changer in the DG procurements.

Probably the other most fundamental improvement, Commissioners, is the ability for distributed generation resources to be subscribed. We've talked already about the success of the other subscription programs, CRSP and CARES and CNI Ready. An unmet customer need are proposing to allow DG facilities to also be subscribed. Open those up to a larger customer base and also the added ability for customers to drive additional procurements beyond the initial target. That has the ability for -- to really add some additional value, both from the developer side on the nonparticipating customer side, and, of course, on the part of the subscribing customer, who can drive the additional procurements beyond the targets.

Q. Any other enhancements to the RFP, Mr. Mallard?

A. (Witness Mallard) I'm sure I could go read them out, if that would be helpful.

Q. Please.

A. (Witness Mallard) Just a second. So I'm reading on page 82 from the main document. So we've already talked about locational value. We've touched a little bit on the extended RFP.

We didn't talk specifically about the buy-down part of the RFP. I'll restate that for the Commission. We talked about it yesterday. But that's the -- after the traditional competitive phase of the RFP, the ability for fully evaluated projects to be offered the opportunity to reprice their submission to a price that would equal the total net benefit average of the entire portfolio. It basically is a form of a bid price refresh, if you will, and would allow additional procurements on that part of the competitive RFP.

VICE-CHAIRMAN ECHOLS: Would you go in reverse order?

How would you start that?

MR. MALLARD: That's an idea. You could -- you could do that way and sort of best price wins. The other way to do it would be to just solve for the -- that total net benefit average and make that same price available.

It's going to be a limited number of projects, Commissioner. It would only be the unselected projects. It would be a limited number of projects.

But one way to do it would just be to make that price available and any project that could meet that price target would be selected.

VICE-CHAIRMAN ECHOLS: Any and all of them?

MR. MALLARD: Any and all of them.

VICE-CHAIRMAN ECHOLS: And they wouldn't have to pay another fee of any sort?

MR. MALLARD: No, they wouldn't. They'd be meeting the same net benefit value as the rest of the portfolio. I think about it this way. If -- if the company on behalf of customers was satisfied with getting 50 megawatts from, you know, 15 projects or so, if there were three or four more projects and could get another 10 or 15 megawatts at the same value, would that be a good idea?

As long as we can still handle that from an interconnection and integration perspective, I think -- I think that makes sense for everybody.

VICE-CHAIRMAN ECHOLS: I think it's one of the best, you know, modifications that you're suggesting on this. I think that, you know, there's -- we've had a lot of developers in the past who have missed it.

And they've really -- they've spent a lot of money. They want to get in there and this gives them a chance to do that. Kind of a second chance. I like it a lot.

BY MR. JONES

Q. These RFP enhancements, how did the company develop those?

Or how did you figure out that those would be good on a move-forward basis or in future RFPs?

A. (Witness Mallard) We get that feedback pretty regularly from DG market participants. Coming out of the last IRP cycle, there was the DG working group, met a half dozen times or so, got some feedback directly from the market. We've been taking that forward and over the course of the last year, the company has hosted feedback sessions with multiple solar market participants, customers, rooftop solar developers, but most with DG developers.

And so these enhancements are based directly on that feedback. We've had multiple sessions and it really has been an iterative process where the company has heard the feedback, offered some solutions. The ones that seemed to hit the mark, we've kept. Some other ones we may have let fallen by the wayside.

These proposed enhancements represent our best case to put forward to have successful RFPs based directly off that feedback from the market participants.

Q. I'm glad you asked about the DG working group. Explain more about that process.

How many meetings did you have? When did it start? Kind of walk us through that.

A. (Witness Mallard) Yeah. I don't -- I don't have all those details. I think there's a data request maybe that offers that. I can tell you they met a handful of times.

It was representatives from the company, from the staff, from the solar development community. Commissioner McDonald put this forth in the '22 cycle to ensure a robust feedback process. And, like I said, I think it's been successful.

I think we got a lot of learnings from that process. And now, by my way of thinking, it's morphed into this more specific feedback process hosted by the company with direct feedback from RFP current and future participants.

Q. And how did that exchange of information happen out of the meetings?

What -- did the company create a report based on those meetings, identifying the feedback and its responses and analyses?

A. (Witness Mallard) Are we talking about the DG working group?

Q. Yes, sir.

A. (Witness Mallard) I'm not familiar. Staff really was the host of the DG working group. Those questions might be better put to staff. I did not participate in any of those. We had our representatives from our DG team participate.

And so they're hosted by staff. I believe Commissioner McDonald, maybe some others, attended at least a few of those. A really good exchange of information with the DG market participants.

I do think I remember a report or an email that comes out after those, but I just can't say for sure. I'm not the -- I'm not the SME on that. I did not personally attend those meetings.

Q. You would -- would you agree, though, that those working groups and things of similar nature, a collaborative effort between participants, bidders, and the company and staff, would allow those RFPs and did allow RFPs to become more flexible and adaptable; thereby allowing the company to ensure it procures as many of the megawatts that this Commission has authorized?

A. (Witness Mallard) Yes.

Q. So that proactive feedback and that proactive adaptation of RFPs is a good thing; right?

A. (Witness Mallard) Yes.

Q. Tell me now about the process for RFPs prior to when they are issued or when bids are solicited.

Do you distribute the RFPs to potential participants prior to them being issued?

A. (Witness Mallard) Yes, yes. And for those not as familiar, the company's request for proposal process follows the Commission's RFP rules that is in compliance with the IRP Act. So it's a pretty prescriptive process to run competitive solicitations.

So similar to the way we run utility-scale RFPs, the company follows the Commission's rules and executes those RFPs in collaboration with the staff, the independent evaluator, and the market participants. Documents are developed based on that feedback we just talked about, shared with staff for feedback, ultimately posted to the IE website for the market to comment.

In conjunction with that, there's a bidder's conference. Ultimately all that feedback is taken into account. The company and staff put together the final PPA and -- RFP and PPA versions. And then those are put before this Commission for approval before they're issued to the marketplace.

Q. Great. And that sounds really collaborative and productive. And the resulting RFPs, though -- the resulting RFPs for DG, we still found that some megawatts had been unallocated and unfulfilled; is that correct?

A. (Witness Mallard) That is correct. But I -- I think that's a feature, not a bug. The company is procuring resources that provide value to customers. That depends on the price of the bids, the viability of the projects. In particular, where they are located.

And so the allocation for DG is more of a regulatory decision, not a model-driven decision. It's based on the feedback that we've gotten from the marketplace and the success of the last few RFPs. It's pretty evident that the market is delivering somewhere in the neighborhood of 90 megawatts or so per three-year cycle.

I think that's really a success. I think that's a lot of distributed generation being added to the grid at prices that benefit all customers.

So that was foundational to the basis of proposing the 100-megawatt target going forward, but I think those targets are just that. They're targets that allow the company to offer the opportunity to bid the best price to the marketplace and then the company selects those projects that provide benefit to customers.

Q. Did you recognize the need for RFPs to become more flexible and adaptive to ensure that the system captured the valuable -- the value of renewable resources and the values that can -- those values that can be offered to customers?

A. (Witness Mallard) Yes.

Q. So anything that can be done to ensure that the company, along with participants, and in conjunction with staff are tailoring those RFPs to be successful as possible is important; correct?

A. (Witness Mallard) No. I wouldn't agree with that.

Q. So you don't think that every effort should be taken to ensure that the RFP procures the resources that this Commission has directed?

A. (Witness Mallard) No. And the word "anything" is -- is really wide open. No. Everything has a cost. Running RFPs has a cost; the cost of the employees that work on it, the cost to the development community to go out and find the project locations, the cost of the independent evaluator, the time it takes.

There is absolutely an efficiency to the RFPs that has to be taken into account. Doing everything to hit a target that's not mathematically based, in my opinion, is not the right thing to do on behalf of customers.

Q. But there's -- there is significant expanse to each RFP, I would definitely agree, which is the reason why we should do our best to ensure that each RFP is fully subscribed or as fully subscribed as possible; right?

A. (Witness Mallard) We should do our best to run an RFP that's fair, that allows market participants to put their best projects forward, and that allows the company, along with the staff and the IE, to select the portfolio of projects that we deem provide value to all Georgia Power customers.

Said more simply, solar at any price is not a good value for customers. The value for customers is in procuring solar at prices that provide benefits as we compare those prices to our long-term avoided costs.

A. (Witness Beppler) Commissioners, we want this process to be iterative, we want it to be responsive, but we also want it to be protective of all of our customers.

Q. You could boil that down to a successful RFP; right?

That's the goal?

A. (Witness Mallard) Is what? Restate the question, please.

Q. The goal is for every RFP to be successful; correct?

A. (Witness Mallard) Yes. And I guess the -- the definition of successful is in the eye of the beholder, Counselor.

Q. Fair enough.

Let's talk now about DERMS. Explain --

CHAIRMAN SHAW: I have a question before you move on from that point. So I just want to applaud our renewables staff for the hard work that they do working with y'all and the community --

MR. MALLARD: Yes, sir.

CHAIRMAN SHAW: -- because they play a critical role in all of this. And I just want to applaud Jamie and her staff for all y'all are doing. Because I think -- we think we're doing it right here and we couldn't do it without y'all.

But, Wilson, you -- you know, feel free to elaborate on how hard our staff works.

MR. MALLARD: I would be glad to. The

collaboration with the staff is critical to the successful procurement, not just through these RFPS. But, look, the way that our overall renewable portfolio and strategy developed over the last 10 or 15 years, we are doing it the right way.

We're not going after some -- some mandate that's not based in science. We're procuring resources at the speed that we can do it that makes sense for customers. Georgia Power, working with staff, and the development community. I want to give them a lot of credit, too.

The folks that are active as stakeholders in the state of Georgia, they are the -- they're the hard workers out there, finding sites, developing projects, getting the projects built and interconnected. It takes all of that to bring these projects in before this Commission for -- for approval and for guidance as we continue to expand solar.

I -- I'm a little biased, I know, but I think we've got one of the best markets for renewable energy in the whole country in Georgia.

BY MR. JONES

Q. And on behalf of the Georgia Solar Energy Industries Association, we applaud staff, too. They've been wonderful and instrumental in fulfilling the renewable procurements that this Commission has ordered.

A. (Witness Phillips) And I'll just add, I don't think the positive interaction and relationship with staff is isolated just to renewables. Staff has certainly been responsive from a DSM perspective, as we continue to try and meet goals and be innovative and flexible. And we certainly appreciate the partnership that Georgia Power has with staff from a DSM perspective, as well.

Q. I've got one, maybe two more questions. And then I'd like to talk about DERMS, if that's okay?

A (Witness Mallard) Yeah.

Q Well, you know, I had another idea. I'm going to move quickly. DERMS is my last topic.

Mr. Mallard, you said procuring from a -- I forget your exact words. I won't ask the court reporter to read it back. But you said it makes sense to procure renewable resources in a calculated mathematical fashion.

A (Witness Mallard) Right.

Q Would you say that prior RFPs and the amount of resources sought to be procured there were based on that scientific approach, if we can just call it that?

A. (Witness Mallard) Yeah. We talked a little bit about the change that happened in Aurora in 2022 that allowed Aurora to select solar resources. That really is a big significant change. And so before that and after that you're going to divide the development of the solar targets into two categories. Now it's absolutely math and science based. And Aurora indicates the amount of resources that -- that the company seeks to -- to procure.

It's more of a policy decision how those resources are divided between utility-scale, DG, or other types of resources. This Commission provided a lot of leadership all the way back in the ASI days by not just procuring the least-cost resources, which would, in almost all circumstances, be utility-scale, but instead ensuring a carve-out for distributed generation that we've already talked about as providing a lot of benefits to the state of Georgia.

Q. And you'd agree the Commission has made the right policy decision in the amount of DG resources it's ordered procured in prior RFPs?

A. (Witness Mallard) I will agree, but let me say it slightly different. The Commission providing these DG targets and then allowing the competitive market process to show how many valuable projects are out there, that is absolutely the right thing to do. A target is -- is just that. But the Commission's approval and guidance to procure resources that are deemed valuable based on their price and their other benefits, that is the real --

that's the real secret that has made our procurements so successful.

Q. And you acknowledge the need that procurements have to adapt, to evolve, and be flexible to reach those targets set by this Commission?

A. (Witness Mallard) Yes.

Q. Okay. The amount of DG resources that the company seeks in this IRP, are those based on that scientific approach?

A. (Witness Mallard) The underlying amount -- the 4,000 megawatts by 2035, that's the underlying mathematical target. We then paired that with the practical and the experience that we've had looking at past RFPs and how much we've procured.

So the long-term target is solved for by math and science. The allocation between DG and utility-scale and the exact targets for each RFP, that's informed by our experience in prior RFPs and our expectation for future conditions in the market.

Q. And now I'd like to moved to DERMS. Can you tell me, in implementing DERMS -- give me your 30,000-foot view just so we can get onto this topic. I know you discussed it in prior testimony, but let's shift gears there.

A. (Witness Beppler) Can you be more specific in your question?

Q. Give me your elevator speech, please, on DERMS.

A. (Witness Beppler) Sure. Highest level, Commissioners, DERMS is a system of system which provides visibility, predictability, and hopefully with -- if the request in this case is granted, control of distributed assets so that they can deliver value to the system.

Q. And how -- what is that implementation?

Is that through a company resource or is that a third-party resource?

A. (Witness Beppler) So the company has contracted with a vendor to provide this software platform. That will then get implemented by integrating this specific software platform with some of the customer -- the company's existing systems -- our energy management system, our advanced distribution management system, and others -- to really give us that system of systems so that we can operate distributed assets in the most valuable way for our customers.

Q. DERMS is about maximizing value of DERs; right?

A. (Witness Beppler) I think that's fair, yes.

Q. What is the request for DERMS in this IRP?

A. (Witness Beppler) It is to enable control of third-party-owned assets. So the ability to dispatch specific program-enrolled resources, like the solar-plus-storage assets that we were describing earlier.

Q. Does that -- does it contemplate an aggregator or someone aggregating smaller resources that then the company can then call on to dispatch?

A. (Witness Beppler) So, again, one of the benefits of a utility-centric DERMS is the ability to incorporate these third-party or edge DERMS. I think you used the term aggregators. That's the -- the platforms which are communicating with the individual end-use devices.

So a couple of examples, Commissioners, would be the -- the implementation of our residential DR program or the managed charging program. Both of those use an edge DERMS, which will then integrate into and communicate with the utility DERMS.

MR. JONES: Okay. Those are all the questions I have. Thank you, Panel.

MR. MALLARD: Thank you.

MR. JONES: Thank you, Commissioners.

CHAIRMAN SHAW: Thank you.

Georgia Solar.

MR. MORELAND: Hey, Commission. Thank you. Thank you, Chairman.

CHAIRMAN SHAW: Thank you.

MR. MORELAND: Hey, Panel. I have some good news. The topic that I will be asking questions about is just about the residential and small commercial solar and battery pilot programs. So I'm going to start off with Mr. Phillips.

CHAIRMAN SHAW: I just want to mention one time that if some of your questions have already been asked, it's already there.

MR. MORELAND: I understand. And I appreciate that. I have been crossing some off.

CHAIRMAN SHAW: Okay.

MR. MORELAND: So I will try to -- I will try to be brief.

CROSS-EXAMINATION

BY MR. MORELAND:

Q. So the capacity -- the target capacity for this program is currently at 50 megawatts; right?

A. (Witness Beppler) That's correct.

Q. And there's two different pathways that customers can choose. And that capacity has been divided evenly between those two pathways for 25 megawatts each; correct?

A. (Witness Beppler) Yes.

Q. What is the rationale for -- for just doing

it at a split 25/25?

A. (Witness Beppler) I think we want to, you know, have options available for customers. Certainly one of the learnings that comes out of this might be that one pathway is more attractive and then we could adjust going forward. But an even split seems like a good place to start.

Q. So if one of the pathways were to be more popular than the other and say -- let's just say the company-directed pathway sells out quickly, there's still capacity left in the customer-directed pathway, would that possibly trigger the situation where Georgia Power would go back and look at the addition of more capacity?

A. (Witness Beppler) Yes.

Q. If just one of them -- so, in other words, customers wouldn't be restricted to use the other pathway because the other one is already sold out?

A. (Witness Beppler) No. I think if we -- if we reached either of the pathway targets, that's an opportunity where we'd come back and -- and utilize that check-in approach.

A. (Witness Mallard) And we'd be informed by the -- the information that we'd have of projects in the pipeline, interest of potential projects. If one was significantly more popular than the other, we could reallocate. But, more likely, it would be a request just to -- just to procure more.

Q. And will Georgia Power provide regular reporting updates to the public on the -- how much capacity is left in each pathway?

A. (Witness Beppler) Yeah. I don't think we've defined all the details of that, but certainly would be open to providing information on how the subscriptions and enrollments are -- are trending.

Q. And so it's to be determined then if that reporting would be based on, you know, at application or at PTO, for example?

A. (Witness Beppler) Sorry. Could you repeat the end of that question?

Q. Yeah. If we're doing regular reporting, like, say, monthly reporting on the capacity that's left in each pathway, is that reporting going to be based on when the application is made to participate in the program or upon PTO?

In other words, how will the industry have any insight into what that pipeline looks like?

A. (Witness Mallard) Yeah. I think we'll work closely with staff and then look from the marketplace to determine that. We definitely gained a lot of knowledge over the last few years from the -- from the monthly netting pilot, and, then again, just the heightened level of customer applications that we've seen over the last few years. And so we'll work closely with staff to understand what is the most meaningful metric to report.

Q. Okay. Going back to that check-in mechanism that's on page 40, line 20, of your testimony. Just to quote a portion of it, it says: The company will -- well, in the event the company reaches the target enrollment before the 2028 IRP, the company will present to the Commission potential program modifications based on lessons learned and seek approval, et cetera.

Does that mean that the company could look at potential program modifications in addition to the capacity number?

In other words, would the company be looking at -- at modifying some of the incentives that is -- are available?

A. (Witness Beppler) I don't think that's off the table. You know, as we testified earlier, we understand that, you know, conditions change. And so as I said to the previous counselor, we want to be responsive to that, but also protective.

So the intent of this target was to identify what we think is achievable and reasonable. It wasn't to imply scarcity. We want these programs to be successful.

We believe that they deliver value both for participating customers and nonparticipating customers. So we're going to do what we are able to to ensure a successful program implementation.

A. (Witness Goff) And this is really in response to feedback we got through the collaboration sessions of: Please don't put a cap on it. We want it to be more of a target.

And so this is direct response to the feedback through those processes.

Q. For the capacity target I understand. But it seems like you're leaving yourself room to adjust some of the incentives available, as well. So, for example, if the customer-directed pathway were to sell out quickly and we need more capacity for that particular pathway, then that could also give you an opportunity to adjust either downward or upward the up-front incentive and the ongoing performance incentive; is that correct?

A. (Witness Beppler) I don't think that's off the table. One of the appeals and another piece of feedback we heard is that we wanted a clear incentive structure and a clear signal to the market. So I don't think we would want to be continuously changing that. But to the extent that there is a fundamental shift in market conditions or -- you know, we have not seen success with

certain program elements, then we could recommend changes to the Commission if we came back.

A. (Witness Mallard) I think it might be -- the changes we consider might be more the mechanics of participation and how the program was working. The values for the incentives are based on long-term system costs. I think those are unlikely to change significantly, even within a three-year cycle.

So the changes we would make I think -- and not an exact science, but the type of thing that could be made in a -- an energy admin cycle type of an approval, not a fundamental program redesign outside of the IRP.

Q. Okay. I appreciate that. Thank you.

Let's talk about the system size requirements. How did the company arrive at 20-kilowatts AC for residential?

A. (Witness Beppler) Yeah. So, again, one of the pieces of feedback that we heard was that there was a desire to allow larger systems than just 10-kW limit in RNR. We thought 20 kW was a limit that would avoid triggering incremental costs, as far as infrastructure upgrades. When you get much beyond that, then you might have to upsize service levels or transformers to be able to accommodate that potential pushback. So this is a balance of trying not to incur additional costs while

being responsive to the feedback that we heard.

Q. Maybe an example will help -- help me understand a little bit further. The Tesla Powerwall 3, as you may know, has a maximum continuous power rating of 11.5 kilowatt-hours -- or kilowatts AC; correct?

A. (Witness Beppler) Subject to check --

Q. Subject to check.

A. (Witness Beppler) -- I am willing to accept that, yeah.

Q. Okay. So based on the 20-kilowatt AC limit, how -- what's the largest you could size your solar energy system to be paired with that?

A. (Witness Beppler) If you were able to export the full amount of that battery, then you would be limited to 8 1/2 kW of solar.

Now, I will -- I will say that that is just to receive the participation incentive. So there is -- again, there's other options for participating and we have discussed previously a number of different programs that could potentially stack, be that solar-plus-storage, RNR. They have some different limitations.

There's optionality for customers. If the specific restrictions on this program don't meet a customer's needs, then there's other ways for larger systems potentially to participate.

Q. Okay. So just to -- I'm -- not to belabor this, but you're assuming that both -- in the example that I just cited, that the 8 1/2-kilowatt solar system and the Tesla Powerwall 3 are both discharging a hundred percent a hundred percent of the time to reach that 20-kilowatt limit?

A. (Witness Beppler) No. But they do have the possibility to export at that 20 kW. And so we're not assuming that all of that will be happening at the same time, but we're protecting against the case where that would be occurring.

Q. Do we know about how often we think that would happen?

A. (Witness Beppler) I can't speculate on that, no.

Q. Would it be possible to maybe look at how often that could happen and then discount it appropriately?

A. (Witness Beppler) It only has to happen once to trigger the types of costs. If you start pushing back energy beyond that and you have a transformer that blows, only one time and the transformer needs to be replaced.

So, you know, this is about protecting the system. We think the 20 kW size threshold is going to cover the vast majority of systems that would potentially

be participating in this program. But, as I mentioned, there is, you know, other options outside of this program if customers are interested in larger systems.

Q. Okay. Let's look at the incentives particularly for the customer-directed. If we're forecasting avoided generation capacity value at $1,000 per kilowatt and then taking the net present value discounted to 75 percent of the shared savings model, then $750 per kilowatt for the -- for the up-front incentive for the company-directed pathway makes perfect sense; right? 75 percent of 1,000.

A. (Witness Beppler) Yes. I think there was a couple of steps that you might have glossed over in there in that you're taking the net present valve of avoided capacity costs over that 10-year contract life to get that $1,000 per kW and then applying that 75 percent. But generally, yes, you're correct.

Q. So then could you just help me understand, how did you get to the incentives for the customer-directed program based on that avoided cost value?

A. (Witness Beppler) Sure. So, Commissioners, the generation capacity avoided costs were consistent across both streams. For the customer-directed, we took a levelized average of the 3-year cycle, so '26 through '28.

We determined a dollar per kW based on those avoided generation capacity costs and then we looked at the expectation of the number of hours it would be called a year.

And so we said the company is committed to calling these resources a minimum of 50 hours a year. And we took that generation capacity value and spread it out over those 50 hours to determine that dollar per kWh pay-for-performance incentive, plus that $15 up-front enrollment incentive.

A. (Witness Goff) And I believe this might have been submitted through a data request, too. If you want more information, that may be also helpful to you.

Q. Okay. Great. Thank you very much.

So with the customer-directed pathway, consumers have optionality there. They can opt out of an event if they want?

A. (Witness Beppler) That's correct.

Q. Can they also opt out of a certain number of hours per event?

A. (Witness Beppler) Yes.

Q. So they can say, just for an example: Yeah, I want to do this event, but just for one hour?

A. (Witness Beppler) That's correct.

Q. Okay. Also, for the customer-directed, there is no agreement that has to be signed for that program?

A. (Witness Beppler) I -- I don't agree with that. So either participation channel would have a customer agreement. The difference I think you may be referring to is sort of the longer term nature of the contract in the company-directed option.

A. (Witness Mallard) Yeah. And all projects would have to follow company current interconnection guidelines in their connect per -- per Georgia Power and Southern Company direct policies.

Q. How long will the up-front and performance incentive be available for the customer-directed?

A. (Witness Beppler) We've -- we've committed through this IRP cycle. So '26, '27, '28.

Q. Did the company consider a longer term for the customer-directed program?

A. (Witness Beppler) We didn't. We think there is an option for those customers who are interested in a longer term in the company-directed option. Certainly if we -- if we hear that feedback through the pilot, then that's something we can consider going forward.

Q. Does the company agree that a term with a longer price lot, quote-unquote, would likely provide greater certainty for developers and program participants?

A. (Witness Beppler) Yes. I think that's fair, but then there's also risks introduced for -- for nonparticipants.

And I want to be clear, we've -- we've committed to offering this level of incentive for the -- the pilot window in the next IRP cycle. That isn't to say that we anticipate that this program goes away.

As I mentioned earlier, we want to make this something that's successful. And so anticipate that maybe with a few modifications based on feedback we receive, this is something that continues beyond the pilot phase.

Q. So it is possible that those incentives, both the up-front and performance incentive, could be increased in the next IRP?

A. (Witness Beppler) Those incentives are based off of our avoided costs. So as avoided costs change, we'll update the calculation of those incentives.

Q. Okay. Did the company complete an analysis comparing the total incentive dollars spent under the customer-directed option through three years versus the up-front incentive payment under the company-directed program?

In other words, you know, how did the -- how do those fair to -- from the customer and the benefits to the customer?

A. (Witness Beppler) I don't know that we did that specific analysis. I will say that the source of the avoided costs and the assumptions that were used to derive the incentives were consistent between the two programs.

Q. Is it safe to say just -- if the incentives for the customer-directed program were consistent over a 10-year period of time, then they would land at or around the same as the company-directed?

A. (Witness Beppler) Around the same. I will note there is a slightly different ELCC value. So we talked about that a little bit yesterday, Commissioners. The effective load carrying capacity differs slightly between the two program options. But outside of that, yes, you would get a similar value from 10 years of participation in both channels.

Q. And as far as the 4-hour duration per event, can you tell us a little bit about how we landed on four hours for that one?

A. (Witness Beppler) Sure. So we did hear feedback and we looked at peer programs. Four hours was something that we thought was reasonable, given the sort of technological capabilities.

That's not to say we'll necessarily always call 4-hour events, but the 4-hour event designation helped maximize that ELCC. So it enabled us to reflect higher incentives for that program participation channel.

Q. Is the number of hours -- is that directly correlated with how the up-front incentive is calculated?

A. (Witness Beppler) Can you be specific with the -- what you mean by the number of hours?

Q. Yeah. So for the -- for the customer-directed, the up-front incentive is divided by four.

A (Witness Beppler) Yes.

Q Whereas, as in the company-directed, it's divided by two.

A. (Witness Beppler) Yes.

Q. And I think we've talked about this before. But just if you could entertain me just for a minute, what -- shortly, what is the difference there and why is there a difference in how that up-front is -- is calculated?

A. (Witness Beppler) Yeah. So, again, Commissioners, we were -- we were trying to maximize the value that we could provide, both in terms of to benefit the system, but also reflect in incentives.

Under the company-directed model where we're having more realtime dispatch capabilities with the batteries a 2-hour battery is capable of receiving 100 percent ELCC at present. And so that is the benchmark that we use to define the incentive level.

On the customer-directed, as I mentioned, it's going to look much more like a demand-response program, in that additional advance notice results in a different ELCC. To try and maximize the value associated with that, we used a 4-hour event window because that has a higher ELCC rating. And so that would maximize the incentive that we could offer through that participation channel.

Q. You mentioned there's a minimum number of hours, 50 hours per year. Based on company modeling, can you anticipate what a maximum number of hours would look like?

A. (Witness Beppler) So we haven't committed to a maximum for a couple of reason, Commissioners. One is that, as we already discussed, customers have the ability to opt out. So if -- if there's larger number of hours and they don't want to participate, they can simply opt out.

But it gives the company a little bit more flexibility in managing the number of events and the hours dispatched. Where if we get to the end of a year and we've already hit 50, but you're on one of those cold winter morning December 31st, you can still utilize those resources. And to the extent that customers respond, they'll be continued to pay for that performance beyond that 50-hour event.

Q. Okay. Do you recall if any of the collaborators in the two feedback meetings suggested 4 hours?

A. (Witness Beppler) I don't recall if that was a specific recommendation, but I do know that we got some recommendations. And -- and, again, we looked at some peer programs which -- which had similar ranges of -- of event hours.

Q. Okay. Let's talk about payments, payment options. So under the company-directed, who will be responsible for issuing payments for the enrolled projects?

Is that the company? Is that the integration provider?

A. (Witness Beppler) So I -- I think the answer to your question will depend slightly on the implementation vendor selected. I will say I do intend -- we do intend that the payments will not be reflected on a customer's bill, but would be a separate payment. And that is really just for ease of implementation.

When you start trying to incorporate things into the bill, it can add complexity and -- and time. So to bring this to market as quickly as possible, we think it's going to be more straightforward to have those

payments be separate. Whether they are issued directly by the company or a third-party vendor, I don't know at this point.

Q. That answered another question. Thank you.

Who will be eligible to receive the up-front payments; customer or if there's a third-party provider?

How -- is there a restriction on where that payment could be made?

A. (Witness Beppler) So I think what you're getting at is the potential to assign the incentive to a third-party?

Q. Yes.

A. (Witness Beppler) Yes. We have considered that option. I think that's something we're willing to entertain. That would be similar to some of our -- our DSM programs.

So we'll need to ensure some customer protections to make sure that that incentive is truly being passed on to the customer, but we understand that in some of the participation pathways and means of accessing these behind-the-meter resources that would allow easier implementation. So, yes.

Q. So some kind of an assignment mechanism is what you're contemplating?

A (Witness Beppler) Right.

Q Is that also true for the performance incentive under the customer-directed pathway?

A. (Witness Beppler) So I think the performance incentive would have to be customer specific, given that they are the one directing more of the usage associated with that.

Q. Okay. Let's talk about the grid charging. Under the company-directed option, the battery can only be charged with a paired solar system; is that correct?

A. (Witness Beppler) Under the company-directed option, the battery would be restricted to charging just from the solar. And the reason there, Commissioners, is we didn't want to be compelling customers to use more electricity to charge those batteries.

Q. Is it possible that energy storage systems not eligible to charge from the grid could have less availability -- available discharge capacity?

A. (Witness Beppler) That is possible, yes.

Q. Which could lead to less capacity available to discharge during -- during an event?

A. (Witness Beppler) Yes.

Q. But you'll be able to monitor that and be able to see all that?

A. (Witness Beppler) Another one of those benefits of the DERMS systems we've been discussing.

Q. So customers would not be eligible to charge from the grid ahead of a storm event or any suspected outages?

A. (Witness Beppler) Again, the intent there is that the battery resource would be charged exclusively by the solar so that the company who's directing the operation of those assets would not be forcing the participating customer to purchase more electricity, more of our product.

Now, to your point, as we continue to gain learnings with the program, that's a design element that we could consider moving forward is to allow grid -- grid charging for those in the company-directed option, as well.

Q. Do you anticipate that requiring the solar to charge the battery could have an impact on the benefits to the customer in that it would be -- the customer would have less use for offsetting its own electricity usage or time of use, arbitrage type of thing?

So could requiring the solar charge the battery limit the ultimate benefits to the customer?

A. (Witness Beppler) I'm willing to agree that by limiting the charging to the solar, you do potentially restrict the -- all the potential availability of the battery. But you also provide some protections for the participating customers in ensuring that they will not be required to purchase more electricity to charge those resources than are being directed on the company's behalf.

Q. Are you familiar with the Duke PowerPair program?

A. (Witness Beppler) Generally, yes.

Q. And they also require the battery to be charged with solar?

A. (Witness Beppler) There are a number of your models that we've looked at that have a similar requirement, yes.

Q. For the Duke PowerPair program, they offer a 36 cent-per-kilowatt incentive -- up-front incentive for the solar because the solar is required to charge the battery.

Did -- did the company contemplate an incentive for the solar?

A. (Witness Beppler) We didn't directly contemplate an incentive for the solar. I will say the structure of the two programs' incentives is very different. So I don't necessarily know that that's an apples-to-apples comparison.

In addition, as we've discussed previously, Commissioners, participating customers will also have the opportunity to participate in RNR, which already provides an incentive for the solar itself. And the intent of this solar-plus-storage program is really to encourage additional adoption of battery storage, not necessarily just stand-alone solar.

A. (Witness Mallard) Again, I'll just make another note about North Carolina. They've got a solar goal, a state mandate, and so incentives for solar are likely driven by compliance with that state mandate.

Q. All right. Let's talk about --

VICE-CHAIRMAN ECHOLS: Are you talking about the carbon plan -- their carbon plan or what?

MR. MALLARD: Yeah. North Carolina, its -- the goal -- I can't remember the name of the plan. But a goal for certain amount of solar. It would be my expectation that that's --

VICE-CHAIRMAN ECHOLS: Yeah. They call it the carbon plan.

MR. MALLARD: Okay.

VICE-CHAIRMAN ECHOLS: But they previously had an RPS.

MR. MALLARD: Yes.

Okay.

DR. BEPPLER: Yeah, they don't have an RPS.

VICE-CHAIRMAN ECHOLS: Thank you.

BY MR. MORELAND

Q. On page 41, line 16, of your testimony -- I'll let you get there. It says: The pilot will leverage the battery inverter for measuring performance and does not penalize customer for non-performance.

Do you see that?

A. (Witness Mallard) Yes. 16.

Q. So for the company-directed, will there be any minimum performance requirements?

A. (Witness Beppler) Can you repeat the question?

Q. For company-directed pathway, will there be any minimum performance requirement?

A. (Witness Beppler) Yes. I think the specific line in the testimony is, I believe, referring to the customer-directed option where you're -- where we're talking about not penalizing customers for non-performance.

In the company-directed option there would be some performance requirements. We haven't exactly determined those details. I think we would work with our implementation partner to -- to define those and include those as part of the customer contract.

Q. Okay. I'm sorry. I read it like three times and it wasn't clear if that line referred to a particular pathway. So I appreciate you clearing that up.

Do we know what those requirements are for the company-directed pathway yet?

A. (Witness Beppler) Again, as I stated, I think we'll work with our third-party implementation partner to define those. And any requirements would be included in the customer contracts.

Q. Does the company anticipate any clawbacks for any of -- for the up-front incentive if there's noncompliance under the company-directed?

A. (Witness Beppler) Yes. I do think in order to participate -- or to protect nonparticipating customers, if these assets are not meeting the sort of performance requirements, we would have a clawback provision to ensure that we didn't pay incentives beyond the value that's realized for nonparticipating customers.

In addition, that optionality can actually provide a benefit to participating customers who might want to, say, move or sell their home the ability to sort of end that contract and return a prorated portion of that up-front incentive based on their participation to date. It provides them additional optionality.

A. (Witness Goff) But, again, everybody should know going in based on customer agreement: Here are the expectations. Here's what's going on in the program.

So everything should be very transparent so people know what's being agreed to.

Q. A hundred percent agree. And I want to talk about that in just a minute.

And that answered my -- you said prorate. So that answered my next question.

And then, you know, who would be responsible for paying that -- that clawback back; the customer or --

A. (Witness Beppler) Yeah. The -- I think it would be the participating customer or the recipient of the incentive.

Q. That makes sense.

For the customer-directed program, kind of the same line of questioning. If for some reason the customer did not participate for that minimum 50 hours per year, are there clawbacks associated with that incentive?

A. (Witness Beppler) No. And given the pay-for-performance model, the incentives would be sort of post hoc. So we would pay out the incentives after the annual performance cycle. And so to the extent a customer opted out or elected not to participate in specific events, their incentive would be reduced, but we wouldn't have the need to claw anything back.

Q. So you wouldn't claw back the up-front $15 per kilowatt --

A. (Witness Beppler) No.

Q. Okay. Annually; right?
A. (Witness Beppler) That's correct.
Q. All right. So I have to ask, just to be clear, there are no instances under which the incentives would be clawed back for the customer-directed program?
A. (Witness Beppler) Again, it's only a one-year contract. So we don't think there would be a need to have any sort of clawback for that participation pathway.
Q. Okay.
A. (Witness Goff) But never say never. I mean, when you said that, that sounded very like you --
Q. I know.
A. (Witness Beppler) Ominous.
A. (Witness Goff) Yeah. It sounded ominous. I mean, the idea is with the customer-directed option, we think customers would want to participate in that so they would respond to events and get additional value.
Q. Right.
A. (Witness Goff) So that's the goal.
A. (Witness Beppler) The incentives are in line such that if they want to receive value from those assets, they are encouraged to participate. That's the basis of a pay-for-performance model.
Q. When designing the program, did the company consider benefits to the participating customer?

A. (Witness Beppler) Yes.

Q. As well as the company?

A. (Witness Beppler) Yes. I think we just went through a pretty exhaustive list of the monetary incentives available to participating customers.

Q. Did you compare the total benefits to the customer versus the costs of the underlying asset --

A. (Witness Beppler) Yes.

Q. -- as part of that analysis?

A. (Witness Beppler) I think I mentioned this earlier. Based on our sort of our guidance of the cost of battery storage systems, we think that these incentives will cover roughly a third of the up-front costs. When you consider the potential to stack federal incentive dollars available through the IRA, that might get you another third of the cost. So you're getting beyond half of the up-front cost of the storage incentive through program participation.

Q. Okay. All right. Let's talk about the application process. Maybe we haven't fleshed that out yet. But just to ask: There will be an application process to participate in the program.

Do you anticipate that being through PowerClerk?

A. (Witness Beppler) Yes, I do think that we

will use PowerClerk or a similar application, vendor. We've had some initial discussions. We released an RFI to -- to the market to gain some insight into the capabilities of -- of different vendors and implementors. And that was included as their ability to interface with that PowerClerk process. So not definitive, but, yes, we anticipate utilizing some of the existing processes.

A. (Witness Mallard) Yeah. And just the short answer is still TBD. PowerClerk generally focuses on the interconnection application. The customer acquisition will be -- depend on ultimately our selection of that implementation partner.

And so once we select that partner, understand their capabilities, marry that with our own capabilities that are established for interconnecting customer-sided projects now, that's where -- we'll put it all back together and get feedback from the marketplace and staff and come up with what's hopefully an easy and efficient application process.

Q. Maybe streamline so -- maybe you can only apply once and provoke the interconnection and -- and this program?

A. (Witness Mallard) We can dream.

Q. All right. Good enough.

Do you anticipate there being a fee to apply

for this program?

A. (Witness Beppler) No.

Q. Who is eligible to submit the application? Do we know that yet?

In other words, is it the customer, is it the installer, is it the system owner, all of the above?

A. (Witness Beppler) I don't know that we've worked out those details specifically. So TBD on that.

Q. Any other documentation that you anticipate that would be required as part of an application for this program?

A. (Witness Mallard) The -- the typical documentation that's already required for interconnection including the one-line diagrams and the contracts, I think those would be modified for this program. And, again, those might differ based on the size and the type of -- of customer.

So those -- we have existing solar and storage facilities now. If any of those existing processes or application details need to be modified, that'll be something that we'll work out through the process.

Q. And just another one to put out there is: You know, at what point will an application be submitted? You know, at -- at what point in the project development

phase?

In other words, you know, maybe in order to -- I mean, do you anticipate a rush of applications just so people can get in before the capacity limits are done, or do they have to have the project along at a particular point before they're eligible to apply for this program?

A. (Witness Mallard) Again, we've -- we've learned a lot over the last few years with implementing our customer-sided programs. As it currently stands, projects really do have to be ready to go. All the data has to be complete in PowerClerk. And so I would foresee a similar type of a process where a project really does need to be designed and developed and ready to go to apply for the program.

Q. If a customer is on the R rate or the GS rate, they'll need to switch their plan; is that correct?

A. (Witness Beppler) Yes. Those are not options that are available for participation in this program.

Q. And do we anticipate when that would need to happen?

Is that at PTO; at the application process?

A. (Witness Mallard) I haven't thought about that one yet. At one of those -- one of those times, yes. Certainly before the system operates.

Q. Okay. That's important, right, because when

are the applications --

A (Witness Mallard) Sure.

Q When is the application going to be accepted, when are the up-front payments going to be repaid along that phase. You know, if it's -- if it's after PTO, that's different than if it's paid during another phase of the development project.

A. (Witness Mallard) Understood.

Q. And then customer protections. Have you considered options to ensure customer protections are maintained under this program?

One idea that our members came up with was perhaps to develop a disclosure form for customers so they know the ins and out, what's allowed, not allowed, as far as the program is concerned.

A. (Witness Beppler) I don't know that we've explicitly considered that. But throughout the development of the program, we've been taking feedback and envision that we will continue to do so as we move into the implementation.

A. (Witness Mallard) Yeah. And customer protection is of utmost importance to the company. I know it is to the solar marketplace, as well. So we want to make sure that customers are protected from -- from, you know, all types of providers. Both the ones that we know locally and maybe some new ones that might be invited into the marketplace based on the rollout of a new program.

Q. Has the company considered having installers be certified and registered to be able to offer this program to their customers?

A. (Witness Beppler) We have not explicitly considered that. Again, working with our implementation partner, we are aware that there are some peer programs who have some of those similar qualifying requirements. So we'll lean on the expertise of the implementing partner to help identify some -- that or additional consumer protections.

Q. Great. How do you intend to -- this is my last line of questioning. How do you intend to procure the implementation partner?

A. (Witness Beppler) Through an RFP process.

Q. And how long do you think that will take? Should this be approved, of course.

A. (Witness Beppler) Itself, I -- I envision, following a hypothetical approval from this Commission, that's something we would do akin to do what we do on the demand-side programs. So in the third quarter of this year, we would prepare and put forward to the market that RFP.

Q. Do you anticipate a start date for the program?

A. (Witness Beppler) We -- we don't have a particular date identified. As you mentioned, we will have to go to the market to identify that implementation partner.

Based on responses that we heard from our RFI, you're looking at probably four to six months from selection of that partner to enable customer enrollment. So I think the midpoint of 2026 is probably a reasonable expectation for when we could begin enrolling customers if this program is approved.

MR. MORELAND: Okay. Thank you. I appreciate it.

Thank you, Commissioners.

CHAIRMAN SHAW: Thank you. Georgia WAND and Vote Solar.

MS. KVIEN: Good afternoon, Commission. Can you hear me all right?

CHAIRMAN SHAW: You might want to just straighten that thing up and pull it a little closer to you.

MS. KVIEN: Thank you.

CROSS-EXAMINATION

BY MS. KVIEN:

Q. First, I had some clarifying questions for the Panel about the company's proposal to expand eligibility under EASE and Hope Works to moderate-income customers?

A. (Witness Mallard) Could you speak up just a little, please.

Q. I will. Is this a little bit better?

A. (Witness Mallard) Yes.

Q. All right. Thank you.

I have hearing problems myself, so I definitely understand.

If I understand the company's testimony correctly, it has not yet determined how it will define a moderate-income customer, and it plans to define this during program implementation; is that correct?

A. (Witness Goff) That's correct. And just to clarify, it's the expansion of the definition for EASE. In program design, we anticipate that going up to maybe 300, possibly even 400 percent of the federal poverty level. But ultimately, we will allow our implementers some flexibility, and all of those detailed plans will be shared with staff for input prior to us going to market.

Q. Thank you. Does the company plan to lump low- and moderate-income customers together into a single LMI class for purposes of determining EASE and Hope Works eligibility, or does it plan to use its existing

low-income classification and separately define moderate income for purposes of eligibility determinations?

A. (Witness Goff) Make sure I'm familiar with what your -- say it one more time, to make sure I'm familiar with the existing classification you're describing.

Q. The existing eligible customers.

A. (Witness Goff) So currently, EASE and Hope Works are based on income qualified customers, so that's currently defined as 200 percent of the federal poverty level. That's what's being implemented during this cycle. What we're proposing here is an expansion of EASE going into the next cycle.

Q. And that would be treated as a single class of eligible customers?

A. (Witness Goff) And when you say "class," I think, like, class of customers, like, residential, commercial, industrial.

Q. Oh.

A. (Witness Goff) Maybe that's not what you mean.

Q. That was not my intent. I just meant were you going to have one definition that encompassed all of the eligible customers?

A. (Witness Goff) So we would let the

implementor determine those actual qualifications. Again, those detailed programs/plans will be shared with staff. Once we determine what those qualifications are, our implementation team will work very hard with that implementor to make sure that we're targeting those customers in the most need in order for us to hit those program goals.

Q. Thank you.

And have funds allocated to these programs ever been underutilized or not been fully spent in previous years?

A. (Witness Goff) I don't have the actual spend. I don't know off the top of my head where we were compared to that, but I do know that we have expanded the measures. We've expanded the income qualification, and, again, we're targeting, like, 17 times more homes in the proposed case than what we're implementing today.

Q. Thank you.

Would you agree that, as a general matter, low-income customers who could usually benefit the most from these types of programs are often the least likely to participate unless there is targeted outreach and support?

A. (Witness Goff) I don't know, but I do know we do have a lot of experience implementing programs for our customers in the most need. And, again, we're expanding

these programs. We want them to be successful. We work with the DSM working group. We work with staff. We work with our implementation team, with our third-party implementor, in order to get that outreach and to target the customers.

With EASE and Hope Works, there's a $5,000-cap per home. So, in other words, these customers benefit by no-cost improvements for them based on the programs that we've laid out. So there is a benefit to these programs that helps the customers have more comfort in their home. They get the benefit of those energy-efficiency savings, and hopefully it reduces their bill through the participation in these pathways.

Q. Thank you.

Does the company have a plan in place to conduct that outreach for the expanded newly eligible customers for these programs?

A. (Witness Goff) Not today. And, again, we want to go through that RFP process. We want to allow the flexibility for the implementor to bring best practices, and those plans will be shared with staff for input. So we do want that outreach to be successful.

And then as we continue to implement, the DSM working group presumably will continue to meet. So to the extent that there's feedback and we can continue to work with that group through that implementation from '26 to '28 to continue to incorporate best practices, we will.

Q. Thank you.

I'd like to next discuss the company's proposed modifications to the DG RFP process and its plans for the two DG RFPs.

A. (Witness Mallard) Yes.

Q. The company testified earlier that there were a number of challenges that required modifications to enhance its RFP procurement processes, and that was on page 26 of your testimony. The company also testified that it has not procured the full amount of resources in the past several DG RFPs. With the improvements that the company is proposing to the DG RFP process, does the company expect to be able to procure a larger percentage of, or the full amount of DG resources that it is approved for?

A. (Witness Mallard) Yes. The company expects the enhancements to the RFP process will make the RFP more successful overall, that combined with the procurement targets at 250 megawatt RFPs in a three-year cycle. We do think that's the most efficient allocation of those megawatts. And, yes, we're optimistic that those RFPs will be able to achieve those targets.

But, again, we're bounded by procuring

resources that provide benefits to customers. We're going to stop. We're going to not procure more expensive resources just to meet a target. If they don't provide benefits to all customers, we're not going to select those in the RFP.

Q. Understood.

Did I understand correctly the company's testimony earlier that the amount of DG resources selected for RFPs -- or for these two RFPs was informed by the amount procured in previous RFPs?

A. (Witness Mallard) That's right. That's right. In the 2016, just short of 90 megawatts. Similar for the RFP in the 2019 cycle. In the 2022 cycle, there were two RFPs, and the first one procured around 42 megawatts. There's good response to the ongoing RFP, so we expect to hopefully be in that ballpark or more.

And so, yes, those procurements over the three-year cycle informed our selection of 100 megawatts for this cycle split into two separate RFPs.

Q. Thank you.

If the amount of DG resources in these RFPs was informed by the amount procured in previous RFPs, which had issues fully procuring resources, and at least in part because of necessary process improvements that the company is now making, in what ways has the company considered that in setting its 100-megawatt target?

A. (Witness Beppler) I'm sorry. Will you repeat that question one more time?

Q. Sure. So if the company has had issues procuring the full amount of DG resources in the last several DG RFPs, and the company's target -- current target was informed by those previous RFPs, essentially, I'm asking why are those previous RFP results an appropriate guide for setting the 100 megawatt target now?

A. (Witness Mallard) Understood. Using the information from the previous RFPs is appropriate because we're basing it on selected projects, not the targets from those RFPs. I would agree, it wouldn't be appropriate to base the current RFP target on the old targets. Instead, one of the improvements is we've looked at the results from the prior RFPs. Those are the amount of megawatts that have proved beneficial to customers, looking at their price and the benefits they offer when compared to avoided costs. So it's the fact that we're basing it on selected projects that gives us confidence that that's a reasonable target for the next RFP cycle.

Q. Would you agree that DG resources offer important reliability and resiliency benefits to the grid?

A. (Witness Mallard) DG resources offer reliability benefits to the extent they add capacity value and energy to the system. Resiliency, if we're talking about recovery from or avoidance of a grid outage, a solar facility by itself without battery storage doesn't provide very many resiliency benefits. That's a reason that the company proposes adding battery storage to the upcoming RFP is to get some additional resiliency benefits from these resources.

Q. And to what extent has the company accounted for these reliability and resiliency, in the case of storage being present along with the project, in determining its procurement targets for DG resources?

A. (Witness Mallard) So to go back -- and we'll talk again about we use a little math and science to come up with the long-term target. These are energy resources. These resources are selected by Aurora because they're projected to save customers money, provide benefits over the life of the assets if procured at economical prices.

Then the allocation between utility scale and DG is made as a policy decision by the Public Service Commission through this IRP processes. Then the amount of resources that's selected is based on the RFP evaluation process using the RCB solar-avoided costs, and the Commission approved an evaluation model that we use in our RFPs.

It takes into account the benefits that the project provides, including the avoided energy, any capacity benefit that they might bring is also evaluated, as well as other components in the RCP framework that are all considered, ultimately, in that value proposition that the company secures through those RFPs.

Q. Thank you.

I have a few questions about the company's solar and storage program proposal as well. You mentioned earlier in your testimony that the 50-megawatt target for the solar plus storage program is a target and not a cap; is that correct?

A. (Witness Beppler) Yes.

Q. In practical terms, what is your distinction between a "target" and a "cap"?

A. (Witness Beppler) I think a "cap" implies scarcity and the removal of the option to go beyond that; whereas, a "target" is more about an achievable level that we can implement without implying that those opportunities won't be available for future participation.

Q. Thank you.

You testified earlier that if the company were to meet one of the 25-megawatt targets within the greater 50-megawatt target for the solar plus storage program before the next IRP, the company would return to the Commission before allowing more participation; is that correct?

A. (Witness Beppler) Yes.

Q. If the target is named as such because it's not meant to be a cap, why is the company proposing it in a way where it might be necessary to return to the Commission before allowing further participation in the program? In what way is that distinguishable from a cap?

A. (Witness Beppler) As we've mentioned, Commissioners, this is a pilot, and so we do want to continue learning through the implementation. We think 25 megawatts in each of these channels is sufficient to gain enough learnings about feedback and potential modifications that we would return to the Commission.

It is distinguished from a cap in that a cap would imply that you wouldn't continue beyond that, and we absolutely have the intention that, when we would return to the Commission, it would be to make modifications to allow us to continue offering the program.

Q. Has the Commission previously raised caps on programs that Georgia Power has proposed or put into effect?

A. (Witness Beppler) Yes. A good example is the residential demand response. So if you look back at the levels in 2022, that was at 25,000 devices, I think. What got approved in the '23 IRP update was a doubling of that program to 50,000 devices. We're here seeking approval in this case for a tripling, so it would potentially reach 150,000 devices.

So, yeah, I do think there is precedent where successful programs have continued to be expanded. Ultimately, that would be a Commission policy decision.

Q. But you would similarly return to the Commission for essentially permission to raise your target; is that correct?

A. (Witness Beppler) That's right.

Q. Does the company have any specific plans for a stakeholder review to expand the program based on the -- based on any early success of the program or high demand?

A. (Witness Beppler) I don't know that we've outlined any specific details, but as we've said consistently, across all of our program offerings, we are trying to incorporate feedback and would anticipate doing that in this program as well.

A. (Witness Mallard) Yeah. We would anticipate making a program filing, if the program is approved in the IRP, subsequent to the IRP, with more of the details of the program for Commission approval. And so through that process, more feedback could be input into the program.

Q. Thank you.

In the company's testimony, the company said

it was addressing upfront cost barriers for low-to-moderate-income customers through the removal of the discount factors application to customers in these segments and the allowing of the stacking of funding sources. Are there any further ways that the company is addressing barriers to LMI participation?

A. (Witness Beppler) I will highlight one additional opportunity, which is in the customer-directed option. We have the ability for stand-alone storage to participate through that channel, so you wouldn't necessarily have to have available roof space to participate in that participation channel.

Q. Thank you.

What plans, if any, does the company have to do outreach to low-to-moderate-income customers on this program?

A. (Witness Beppler) As we've mentioned, we've been in collaboration with some other potential sources of funding, including those solar-for-all dollars. We think that's a really cost-effective way to target those populations.

Q. And when the company was designing the company-directed option under the solar plus storage program, did the company consider granting participants a very limited degree of opt-out ability so that the company

would maintain control for the vast majority of the use of the system, but the customer would have a limited chance to opt out during, maybe, emergencies? For example, one or two opt-outs per year?

A. (Witness Beppler) We did not explicitly consider that in designing the program, no.

Q. Moving on to my last topic, I'd like to discuss the company's DSM efforts with data centers and large-load customers. You testified earlier that the company has engaged with large-load customers like data centers about demand-side flexibility?

A. (Witness Goff) That's correct.

Q. In this engagement, has the company asked its large-load customers what it might -- what might be lacking from its current DSM program offerings to further incentivize their participation?

A. (Witness Beppler) Yes. One of the things that we heard was large-load customers had a preference for customer ownership of assets that might participate in a DER program, and we've addressed some of that feedback with the new offering that we've put forward in this filing, the large-customer-owned resiliency program.

A. (Witness Goff) And as we spoke to before, there are options available for data centers to participate in our DSM programs. That's not the focus of them, but they absolutely have the option to participate. Those measures included -- data centers are some of the largest energy users, and they have every incentive to be as efficient as they can. They're extremely sophisticated and monitor this stuff. So, you know, for those reasons, there are options. And we'll continue to get feedback, but that's something to just consider.

Q. Thank you.

Were there any other -- just wanted to make sure, were there any other things that those customers identified as potentially lacking from current DSM programs, besides the one example?

A. (Witness Goff) Again, "lacking" -- I don't think that there's a lack. I think these are extremely large, sophisticated companies, and they have every incentive to do this on their own. There are options available to them, and so they can participate. But, you know, to the extent they're able to, that's great, but they also are potentially doing that on their own as well.

Q. Has the company discussed with these large-load customers about how just a small amount of flexibility on their part during peak periods could result in systemwide benefits for all customers, including a lower-per-unit cost of electricity, a reduction of the likelihood that expensive new peaking plants or networks needed to -- would be needed to accommodate that new load?

A. (Witness Goff) That is an industry conversation. I think that is absolutely being had across the industry. Dr. Beppler mentioned the DCFlex initiative going on with EPRI. And, you know, data centers have expressed an interest in being partners in the grid.

Georgia Power has proactively brought programs to this Commission to allow for that flexibility and for those resiliency assets and other things to be used for the benefit of all customers. So a variety of options from a DER space. And as Dr. Beppler mentioned before, from a curtailable load perspective, from a rate perspective, the tools are there from a Georgia Power perspective. We've brought forward additional options in this IRP to continue to expand that portfolio.

Q. Given that data centers represent a vast majority of load growth in Georgia, and that even a small amount of flexibility from those customers could yield system benefits, is there a reason the company has not developed a data-center-specific DSM program to help realize those DSM benefits?

A. (Witness Goff) These are sophisticated large users. To create a program, stand-alone, for them -- again, we typically don't do that. We like to have programs that can all bucket under one program. That reduces administrative costs, it makes things more cost effective. And so to carve out another program for data centers alone, you know, I think we would be concerned about the cost effectiveness of that, given the potential benefits that would provide.

A. (Witness Beppler) And I'll add there that our existing DSM programs are funded by all residential and commercial customers, so restricting eligibility of participation to just one specific type of customer would be inappropriate.

A. (Witness Phillips) And we have a number of measures or energy-efficiency options available to data center customers, whether it is around more energy-efficient servers, around whether it's a building envelope, or some of the systems for cooling the facility. Those options are already existing in our current programs.

A. (Witness Goff) The options are there, and we feel like we've provided them in a cost-effective way.

Q. You earlier testified in response to Mr. Sherrier that you have not offered incentives, like faster interconnects, for customers who are willing to provide a certain amount of load flexibility; is that correct?

A. (Witness Beppler) No, I would disagree. I think the testimony was actually that the new program offering is intended to do exactly that, which is expedite some of the timelines associated with participation in those programs and getting that capacity reflected on ledger for the benefit of all customers.

Q. All right. Thank you.

Has the company engaged with other utilities in the country about programs that they have offered that are designed to encourage data centers and large-load customers load flexibility, such as PG&E's Flex Connect program that allows those loads to be connected faster in exchange for flexibility at the margin when the system is constrained?

A. (Witness Goff) We have engaged with other utilities across the industry. I don't know about PG&E specifically, but, yes, we absolutely are engaging across the industry. Any best practices we can learn, we always want to learn best practices.

Q. Were the company's existing demand-response programs designed with modern data centers specifically in mind or were they designed with more traditional customers in mind?

A. (Witness Beppler) I think it depends specifically on the program that you're referring to. Certainly, we think the structure of those programs makes them suitable for participation from our traditional industrial customers, but also for these new data center customers that you describe.

Q. Do you believe that the company's existing DSM programs offer benefits and incentives tailored to the uniqueness of participants like certain data centers who would be able to have near-instantaneous response by adjusting workloads?

MS. PRYOR: Objection. I'm sorry, but the witnesses have answered these questions multiple times.

COMMISSIONER PRIDEMORE: So many times.

MS. PRYOR: Asked and answered.

CHAIRMAN SHAW: Please try to stick to questions that have not already been asked.

MS. KVIEN: I'm sorry. I thought I was addressing a unique point there about instantaneous response. Apologies if it was already covered.

I will conclude my questions there.

CHAIRMAN SHAW: Okay.

MS. KVIEN: Thank you.

CHAIRMAN SHAW: Next is MARTA.

CROSS-EXAMINATION

BY MS. STURM:

Q. Good afternoon, Commissioners. Good

afternoon, Panel. I'm going to turn our attention to a totally different topic, the V2G program. One, let me commend you-all for adding that. I think that's a great pilot program to bring in. I'm curious, was any consideration given to expanding that program or maybe doing a companion program to incorporate public transportation fleets?

A. (Witness Beppler) Yeah. I don't know that we've explicitly considered that to this point, but that's something we would certainly be open to in the future, yes.

Q. Well, you answered my second question.

MS. STURM: Thank you. That's all I have.

CHAIRMAN SHAW: All right. Microsoft.

MR. DOWDY: No questions, Mr. Chairman.

CHAIRMAN SHAW: Resource Supply Management.

CROSS-EXAMINATION

BY MR. BAKER:

Q. Good afternoon, Commissioners. Good afternoon, Panel.

A. (Multiple Witnesses) Good afternoon.

Q. Robert Baker for Resource Supply Management. A few preliminary questions. Could you tell me if Alabama Power and Mississippi Power have DSM programs also?

A. (Witness Beppler) I'm not sure that that's germane to the Georgia Power IRP.

Q. Well, let your attorneys make that -- I'm asking in regard to, first, do they have them? Are there programs that are in place in Mississippi and Alabama that Georgia Power can get the benefit of their experience and apply it here in Georgia? Or vice versa, Georgia apply in your sister companies?

A. (Witness Goff) Yeah, I --

A. (Witness Phillips) I believe they do have programs. I'm not familiar with the specifics of either the Mississippi or Alabama Power programs.

A. (Witness Goff) Well, and as we stated before, we do look for best practices across the industry. We absolutely want to incorporate the best practices that we can for the benefit of our customers here in the state.

Q. Thank you. Thank you.

Of Georgia Power's approximately 2.7 million customers, about how many of your customers participate in the DSM programs today, just approximately?

A. (Witness Goff) I don't have those numbers. In general, there are more customers, from a customer count perspective, that participate in our residential programs, but a lot of energy savings come from our commercial programs. So it may be more savings per customer on the commercial side. I don't have the customer count here with me today. That might have been a -- that might have been in a DR somewhere, I can't remember.

Q. Okay. So you wouldn't know if it was 10 percent participation or 15 percent or anything?

A. (Witness Goff) I don't. But what I can say is that, again, we have been at these programs for a long time. We've proposed some additions to our program plans for this cycle, and with the Commission's approval, would anticipate being in those programs in the future. So as you zoom out and look over a long period of time, you know, hopefully, we're providing, and our aim is to provide benefits to as many customers as we can.

Q. Thank you.

And how do you define "a participant" in the DSM program? And I'll refer you to your Appendix B entitled, "Summary Of DSM Program Participation."

A. (Witness Phillips) What was that appendix?

Q. Appendix B.

A. (Witness Phillips) Is that in the application for certification of DSM?

Q. It was attached to your testimony, part of your testimony.

A. (Witness Goff) Appendix B, Summary of DSM Program Participation?

Q. I understand from your attorney it's the application.

A. (Witness Goff) Yes, sir. Appendix B, Summary of DSM Program Participation.

Q. Yes, ma'am.

A. (Witness Goff) Yes.

Q. How do you define "a participant"?

A. (Witness Goff) So in this exhibit, and I'll invite Mr. Phillips to weigh in here too. This is labeled the number of installed measures, so this would be a projection of the number of installed measures for both residential and commercial, by program, for the forecasted period.

A. (Witness Phillips) And it's certainly possible that one customer could install multiple of these measures. I think that's obvious, given the fact that in 2026 we're projecting 3.7 million measures, which is above the number of unique customers that we have.

Q. All right. So if somebody was having their home energy -- made energy-efficient, if they replaced four windows, that would be considered four participation --

A. (Witness Phillips) Four unique measures -- four unique installations of that particular measure, yes.

Q. All right. Thank you.

And on the chart, something that just struck me is that in some of the categories, they don't change. The numbers don't change over the 12-year period that that chart covers. Why is that? Why is there no -- I could point you to -- the residential demand response is 150,000 throughout the entire 12-year period, commercial custom is 456 throughout the 12-year period. Why no fluctuation or --

A. (Witness Phillips) The reason for no fluctuation in the demand-response program is, like Dr. Beppler just testified, historically that has been capped at the number of devices approved by this Commission. So in the '22 IRP, that number was 25,000; the '23 IRP update, that number was raised to 50,000; now, we're seeking approval to increase that number to 150,000 for this particular IRP.

A. (Witness Goff) And we have expanded the definition of that program for to be residential demand-response. So what we have included here is we have evaluation results on the thermostats, so that's what we've included from a program design.

As we go through an RFP and select an implementor, we would be open to a pay-per-performance model if someone were to bring that, to allow for other connected devices, if an implementor could achieve those savings within the budget that's approved by this Commission.

Q. Let's say for commercial customers it's 456. Is that also limited by a cap on participation?

A. (Witness Goff) So the commercial custom program -- and it may be either outlined in the program plans or in the work papers we've provided -- there are incentive caps associated with that program. We have expanded those caps in order to generate larger projects with larger savings in order to meet these aggressive targets laid out in the proposed case.

Q. Okay. Thank you.

For every dollar spent on DSM programs, how much -- approximately how much goes to customers? Is it about 25 percent, or what would you estimate, based on your knowledge?

A. (Witness Phillips) Are you asking about specifically incentives that --

Q. Incentives, the rebates that are offered through the DSM program. So I'm not asking for a specific dollar amount, but, I mean, about how much of that money goes directly to the customers?

A. (Witness Phillips) Well, I think our entire incentive budget would go to the customers. Historically, and I believe in the '22 IRP, on average we were funding about 50 percent of the total incremental costs towards incentives. And then as we have already stated, in our proposed case, a number of the programs, we are asking for funding up to 100 percent incentive for those programs and those measures.

A. (Witness Goff) So give or take, 80 percent of total budget is incentives, and 100 percent of those incentives go to the participating customer. The entire cost of the program is borne by all residential and commercial customers.

Q. Thank you.

General question, there has -- with the new Trump administration and the policies that the Trump administration either has implemented or what reasonably could be expected will be implemented, would any of those have an impact on the programs that you have been putting forward?

A. (Witness Goff) No, and this is something that, over the years, the company has always designed its programs to meet the goals with the budgets that are approved through this process. To the extent federal funding is available, then that is just an added benefit to customers where they can take advantage of additional funds, but our goals are not predicated on that funding being available. So that doesn't impact what we've laid out in our proposed case.

Q. I wasn't thinking so much as funding as far as just policy -- total policy direction. I think you probably agree that the Trump administration is probably going to go 180 degrees from what the Biden administration had proposing in the past or implemented in the past.

A. (Witness Phillips) I'm not aware of any specific changes to the proposed case that would result based upon changes at the federal level. Doesn't mean it's not, I'm just not aware. I do think from an economic standpoint, for the proposed case, the company evaluated cost-effectiveness under an MG0 economic scenario and a 111 economic scenario. And depending upon what might happen with some of those rules and legislations, it could affect the cost-effectiveness, but I think that's another reason why the company did provide two different views of economics for the proposed case for this Commission's consideration.

Q. Thank you.

And the company submitted, or developed, four DSM case projects -- case evaluations, and the proposed case, which is the one that the company is putting forward, is their recommended case?

A. (Witness Phillips) Correct.

Q. And isn't one of the company's objectives in the DSM program to minimize upward pressure on ratepayer rates?

A. (Witness Phillips) That is one of the considerations. Ever since the 2004 IRP, the Commission directed Georgia Power to bring forth a proposed case that accomplishes two things: Number one, maximize energy efficiency, while at the same time minimizing upward pressure on rates.

For this particular IRP, based upon the results of the Vogtle prudence order, the company was also directed to file the case that achieved .75 percent of savings -- .75 percent based upon retail sales, so that's what our proposed case has included.

Q. And that goal would not be achieved through the capacity and affordability case?

A. (Witness Phillips) No. The .75 percent of retail sales was specifically for the proposed case. That does result in significant costs, both from an annual perspective as well as upward pressure on rates and costs to nonparticipants. As noted in the testimony, the capacity and affordability case was offered as another view, another consideration, at lower levels, lower costs, and lower impact or upward pressure on rates.

A. (Witness Goff) And while it doesn't target .75 percent of sales, it does have other benefits, like we described earlier, in terms of -- it targets programs with the most capacity benefit and targeting customers with the most need. It's just an option. Like you mentioned before, there's lots of options out there, and our case is the proposed case.

Q. For the affordability -- for the capacity and affordability case, what retail savings does it achieve?

A. (Witness Goff) Oh, okay. So the capacity and affordability case targets or it achieves 310 gigawatt hours per year of energy reduction; 156 megawatts per year of demand reduction; at annual budgets of 140 million. And, again, that compares to the current cycle of 500-gigawatt hours of energy $90-million budgets, and the proposed case of 741-gigawatt hours at $570- to $580-million budgets.

Q. But your goal here for the proposed case is .75 percent of total retail sales. What percentage of total retail sales would be projected to be achieved through the capacity and affordability case?

A. (Witness Goff) So in general, the company has, I think, about 100,000-gigawatt hours of sales in its forecast. So whatever 310 is divided by that number, give or take. But just to reiterate, the capacity and affordability case is a subset of programs that are targeting programs with the most capacity benefit and targeting customers in the most need. It's not necessarily generated to achieve a certain percent of energy sales.

A. (Witness Phillips) The 308, 310-gigawatt hours that Witness Goff spoke of, is about half of the 741-gigawatt hours. And so relatively, the percent of total retail sales would be a little less than half of what the proposed case is achieving.

Q. Okay.

A. (Witness Goff) But again, the focus is not -- the focus, like we described, is programs delivering the most capacity benefit and targeting the customers in the most need.

Q. Understood. Understood. But as, I think, as somebody here said, very on point, is that everything has a cost. Every -- I think maybe Mr. Mallard was talking about a different subject, but he basically said, I think -- purchasing solar, it may have been -- and that there's a cost for everything, and -- related to the benefit that you receive, so... In this particular case, I believe your prior testimony has been that the current budget is approximately $90 million, and that could project -- you're estimating it's going to go up to $570 million. Would you agree that that's going to have a significant impact on the rider that is charged to every single residential and commercial customer on Georgia Power's system?

A. (Witness Goff) So the information about the impacts to the DSM rider are included in our filing, in Appendix G of the DSM filing. So that information is made available.

To your point, everything in life, I guess, has a cost, and everything has a benefit. And for many IRPs, including this one, we come with our best plan. And ultimately through the process, we will look to the Commission to help us balance the cost with the benefits of what we put forward.

Q. Thank you.

And would you agree, or would you say, that it's true that Georgia Power Company can -- Georgia Power Company's marginal cost of power is much lower -- is lower than the alleged savings produced by the DSM programs?

A. (Witness Phillips) When you refer to "the marginal cost of power," can you be more specific?

Q. All right. It's the -- I'll refer you, then, to -- I believe it was page 44 of your testimony, in which -- let's see -- that was 44, line 15. Maybe it's -- it referenced there in the testimony that 4 cents is more than the company's avoided cost. Let me change that to --

A. (Witness Mallard) So this section, Mr. Baker, is talking about the company's solar-avoided-cost rate. We discussed that a little bit earlier. That's the avoided cost projection that's calculated specifically based on solar energy's production curve. And so that amount is meant to represent the avoided energy costs of the solar system connected to Georgia Power's grid.

Q. Thank you. Now -- so you're saying that you don't know what the marginal cost of power generation is?

A. (Witness Beppler) I would disagree with that. I think you were asking a line of questions about DSM savings, and then referenced solar-avoided-costs calculations. Help us understand the connection.

Q. All right. I'll try to clarify my question.

Going back to the question, would you agree that the company's cost of marginal power generation is less than the cost of the -- less than the savings from the DSM programs?

A. (Witness Beppler) No. I would not agree with that.

Q. Why not?

A. (Witness Beppler) The savings associated with DSM measures are evaluated using the company's avoided costs. So Witness Phillips can speak more to this, but in the calculation of the cost-effectiveness tests, the company uses avoided costs, as you described, marginal

costs, to evaluate the benefits associated with offering those programs.

A. (Witness Goff) And those avoided costs are the same avoided costs that we use -- or marginal costs, for all of the program design that this panel is representing. So that's the benefit of this process is we have consistent assumptions, we have a flexible process, we continue to evaluate and update those things as part of this design.

A. (Witness Phillips) And I think I can provide a little more perspective. One of the first steps, Commissioners, in evaluating energy efficiency, from a cost-effectiveness standpoint, is identification of the benefits. And the benefits to the system are the avoided costs that are realized by participants installing and implementing energy efficiency.

The next step, once you've identified the benefits, are the costs. And depending upon the perspective, the costs might be different. But from a system perspective, the Georgia Power perspective, the benefits are the avoided costs that are realized by customers implementing energy efficiency.

Depending upon the specific tests, then you evaluate the costs, and you mentioned the upward pressure on rates. The RIM test quantifies what that upward

pressure on rates is. And the costs included in the RIM tests are the cost of the programs, both the program costs, the incentive costs, as well as the lost revenues that are realized by customers implementing energy efficiency.

And if RIM were equal to 1.0, or greater, then what that would tell us is that the benefits that the system is realizing is equal to the cost of the program, as well as the savings our customers realize by implementing energy efficiency, but that's not the case. RIM is negative. Energy efficiency is negative for this proposed case, as well as previous proposed cases.

And what the Commission has directed the company to do, as I mentioned since the 2004 IRP, is to seek a balance between maximizing energy efficiency while minimizing that upward pressure on rates.

Q. Thank you.

And do any of the residential DSM programs pass the RIM test?

A. (Witness Phillips) No.

Q. And --

A. (Witness Phillips) Excuse me. The energy efficiency programs do not pass the RIM test. I believe the thermostat DR program does past the RIM test.

Q. Okay.

A. (Witness Phillips) Were you asking specifically about residential or commercial programs?

Q. Residential. I was asking about residential.

A. (Witness Phillips) Subject to check, I believe the only program that does pass the RIM test is the thermostat DR program.

Q. Okay. Thank you for that clarification.

At page 9, you state that by 2028 -- if you want to look, it's page 9, line 19. At page 9 you state that, "By 2028, the current DSM portfolio of 1,400-megawatts will represent 8 percent peak saved, claimed overwhelmingly from realtime pricing customer response and not from DSM."

A. (Witness Goff) I'm sorry. Do you mind saying the page reference one more time? Page 9 --

Q. Page 9, line 19.

A. (Witness Goff) 19.

Q. You got it?

A. (Witness Goff) Yes, sir.

Q. At page 9 there, you talk about the DSM portfolio of 1,400 megawatts that represents 8 percent of the peak saved, and that will be claimed overwhelmingly from the realtime pricing customer response; is that accurate? Is most of that the savings coming from the real-time?

A. (Witness Beppler) I don't see anything about real-time pricing in the lines you've highlighted in the testimony there.

Q. All right. Well, then doesn't the DSM response only represent 225 megawatts of savings?

A. (Witness Phillips) Could you ask that question again, Mr. Baker?

Q. Doesn't the DSM response, as part of that 1,400 megawatts, only represent 225 megawatts of savings?

A. (Witness Goff) So the 1,400 megawatts in the testimony is -- and I think we might have mentioned this before, that's a broad number that incorporates things like DSM, RTP -- RTP -- nonroutine-RTP response, our CVR, or conservation voltage reduction program, DPEC, thermostat DR, so that is a broader number.

But you are correct, the proposed case does deliver 224 megawatts of demand reduction based on the plans and the budgets that we've put forward in our proposed case.

Q. Out of the 1,400 megawatts?

A. (Witness Beppler) Can you ask the question again?

Q. No. No.

Is the 224 megawatts of savings part of the 1,400 that you're claiming on page 9?

A. (Witness Beppler) Yes. The 224 megawatts of demand reduction would be included in the 1,400 megawatts of demand reduction through 2028.

Q. Okay. And if 224 megawatts of savings is from DSM, where did the other 1,200 -- approximately 1,200 megawatts come from?

A. (Witness Beppler) So I think the 1,400 megawatts is including the existing portfolio of DSM measures, whereas the 224 is referring to the incremental savings from the newly proposed programs.

Q. All right.

A. (Witness Goff) And, again, the total 1,400 includes things like DSM, our RTP -- nonroutine RTP response, DPEC, CVR, temp check. So it's a wide variety of programs, which I think is a benefit because we have a wide variety of things that we can count towards our resource ledger.

To the extent the 224 megawatts through the proposed case is approved, then that number will adjust as we adjust all of those demand-side options and reflect the most up-to-date information on our resource ledger going forward.

Q. Okay. Thank you.

Referring -- I'm going to refer you to page 20, line 13. At page 20 you state, "The DSM program economics are declining due to substantial resources and higher incentives needed to achieve high energy savings in the proposed case."

With declining program economic, shouldn't all failing DSM programs be eliminated?

A. (Witness Phillips) Mr. Baker, what line were you referring to?

Q. Thirteen, line -- page 20, line 13.

A. (Witness Phillips) And what was your question?

Q. The question is, with declining program economics, shouldn't all failing DSM programs be eliminated?

A. (Witness Phillips) Well, that's not our ask of this Commission. For the programs where we already are in the marketplace, where we already are engaged with our customers, we have asked the Commission to consider a TRC waiver for those failing programs. And several of those failing programs are programs specifically directed towards income-qualified customers. And this is not the first time we've asked for a TRC waiver. We did ask for one in the previous IRP for the thermostat DR program, due to the changes in system costs, and the costs that that program now helps avoid. That program is TRC positive.

And so while several of the programs in our proposed case do fail TRC, we have asked this Commission to consider a waiver for those programs so that we can continue to be in the market, to offer those programs to our customers, especially our customers who are in greatest need.

A. (Witness Beppler) And I'd like to add, I think there are additional benefits to the company offering DSM programs in terms of customer expectations and customer satisfaction. This is an opportunity to provide customers agency over their energy decisions.

Q. But isn't it true that the company is eliminating some programs that don't meet the financing requirements, such as the refrigerator program? I'm sure customers would love to have you pay them to take away their old refrigerator, but you're ending the program because it doesn't make fin- -- it isn't financially sound. Why not -- isn't that -- shouldn't that be a policy for all DSM programs?

A. (Witness Goff) So we look to the Commission for the policy. Since 2004, the policy has been to maximize economic efficiency through TRC, while minimizing upward pressure on rates. We are asking for decertification of three programs: The residential refrigerator recycling, the residential specialty lighting, and the commercial behavioral.

None of those are cost effective, and so those are programs that we're asking to discontinue. We are asking for four TRC waivers in our proposed case in order to meet .75 percent of sales. Two of those programs are targeting customers that are in most need.

So when you look around the industry, it's not uncommon for those type of programs to actually be assumed of a TRC of one. So two of the waivers, even though in Georgia we are required to file those as a request to the Commission, I did just want to note that those are for that income-qualified and low-to-moderate customer base.

A. (Witness Beppler) And I think as Witness Goff testified earlier, there's some other challenges that have been identified in the programs that we're seeking decertification for, in terms of implementation of applicability, or the market for implementors for those programs, that would make them difficult to continue going forward.

A. (Witness Goff) Yeah. And I'm happy to go through those again, if that's helpful.

Q. No, you've answered the question. Thank you. I appreciate it.

You have a subscription, a utility scale and DG subscription program. When a customer subscribes to one of those programs, is that energy or power from that program specifically dedicated or assigned to a -- that customer? Is that how it works?

A. (Witness Mallard) Definitely not. The whole purpose of allowing subscriptions to our renewable resource is to allow customers access to the REC: The Renewable Energy Credit. What they're really subscribing to fundamentally is the renewable attribute. Those attributes are measured on kilowatt-hour, megawatt-hour basis.

So it's a subscription to the energy. The benefits, the energy that the resources produce, actually go to serve the entire customer base. So the customer's just subscribing to the attribute, the Renewable Energy Credit.

Q. Okay. Thank you for that clarification.

And there's been some questioning and discussion about large-load customers and DSM programs. Is it your experience that energy conservation is just good business for large-load customers?

A. (Witness Beppler) I don't know that we can speak specifically for those customers. We do believe that particularly those large customers are sophisticated and able to make economic decisions on the costs and benefits of energy usage for themselves.

Q. And then those customers will hire energy consultants to assist them, help reduce their energy load, to help make them more efficient, and to help reduce their costs of operation; isn't that generally true?

A. (Witness Beppler) I think that's an option that's available to them.

Q. And then most businesses are interested in being efficient and maximizing their earnings; isn't that true?

A. (Witness Goff) We have a variety of programs for our commercial customers to help them be more efficient. The incentives that we offer do allow customers that may not have those funds available to incent more behavior and adopt more energy efficiency.

So through the expansion of the caps in our commercial programs, we are targeting larger projects with larger savings in order to reach a larger goal through our proposed case.

Q. Agreed. I'm just focusing on -- there's been some question about why large-load customers aren't included and don't have their own DSM programs, or data centers don't have their own DSM programs.

Also, isn't one of the consequences of expanding DSM programs to data centers or to large-load customers that there's a cost of those programs that would then have to be shifted or spread across all customer classes; isn't that correct?

A. (Witness Phillips) When you mention large loads, we have large industrial customers. We have large commercial customers. Could you be more specific what you're referring to when you say "large loads"?

Q. Anyone who is not currently a participant in the commercial DSM programs.

A. (Witness Goff) And so just to kind of recap: We do have options available for data centers, if they would like to participate in our DSM programs. There are options available to them. They're not precluded from that. There are options available.

We don't have a standalone DSM program in the DSM application for them. It's more cost effective to roll them into other DSM programs. There are also DER programs. There's rate options available. There's lots of options, I think, as we've kind of gone through, that Georgia Power has proactively brought to the Commission for approval to allow data centers to be flexible to provide benefits to the grid.

Q. And that's great, that the company is forward-thinking and is offering this to the data centers. But also, if they're offering these programs and the data centers participate, isn't there going to be a cost to the company that the company will then have to recover?

A. (Witness Phillips) Well, there's certainly a cost of the programs. There is the cost of administering, there's the cost of incenting, and so there are costs realized whenever the company pays an incentive.

And so there are some costs -- we have to hire up. We have to hire contractors. We have to market. So there's a number of costs that the company will incur, and we recover that -- those costs through the DSM rider. What we have specifically asked this Commission for consideration is the proposed case. And from both a residential and a commercial perspective, those costs have been included and presented for this Commission's consideration.

A. (Witness Goff) So DSM costs, as Mr. Phillips mentioned, through the DSM riders; Dr. Beppler could speak to the way that the incentives for the DER programs are set up, whereby we're -- essentially, that shared-savings model that we've been talking about, based on avoided capacity costs.

Q. But what I -- I hear you. My -- my -- what I hear you say is that, if there are costs associated with the company implementing a DSM program for data centers or for large-load customers, those costs will be recovered from their ratepayers, residential and commercial ratepayers; is that correct?

A. (Witness Goff) And we don't have a data-center-specific-DSM program. We do have commercial programs that they could participate in, if they would like, and those residential and commercial DSM dollars our request for the Commission is to approve the continued collection of our DSM dollars through the DSM riders through the rate case process.

A. (Witness Beppler) And I'll just add that those commercial customers, if they are large loads also contribute to the DSM rider, and so are paying for some of those costs as well.

A. (Witness Phillips) And, Mr. Baker, yes, all residential customers fund the DSM programs. All commercial customers fund the DSM programs, whether they choose to participate or not.

Q. Thank you.

MR. BAKER: Thank you, Panel, for your time. Thank you for your answers. I appreciate it.

Thank you, Commissioners.

CHAIRMAN SHAW: Thank you, Mr. Baker.

Panel, do y'all need a break?

MR. PHILLIPS: Do we have an estimate on how much longer we've got?

CHAIRMAN SHAW: Yeah, we're going to try to go to 5:45 or somewhere in there.

Keep rolling. All right.

Sierra Club, Southern Alliance for Clean Energy and the Natural Resources Defense Council.

MS. ARIZA: No questions.

CHAIRMAN SHAW: Southern Renewable Energy Association.

CROSS-EXAMINATION

BY MR. COX:

Q. Good afternoon, Commissioners, and Panel. I just have some brief questions about utility scale renewable resource procurement.

A. (Witness Phillips) Sure.

Q. And, first, I'd like to thank the panel for answering many of our questions, and the other parties for asking good questions. So turning to page 26 of your testimony.

A. (Witness Mallard) Yes.

Q. So on page 26 of your testimony, you mention that several challenges have limited the company's ability to meet its renewable RFP targets. Can you just briefly clarify and explain the issues that have limited the company's ability to meet its utility scale RFP renewable targets?

A. (Witness Mallard) Yeah. And I'll just go down the list starting at line 16, so the changing interconnection processes and requirements, we've talked about that. The new cluster study process and how that FERC-governed-interconnection process might impact timelines and requirements for participants in our RFPs. The impact from regulatory uncertainty -- gosh, we could spend a long time talking about the potential changes that might be on the horizon to tax credits, to incentives, to tariffs, otherwise, that -- other policy changes that might impact solar development and procurement.

Increasing scrutiny in land use, the Chairman has mentioned this one already. There's more and more focus every day and month that goes by on land use, the impacts to the land in Georgia, and how to make sure that we're mitigating those impacts properly as solar continues to expand.

Supply chain impacts, that's still happening today. It's much better recovered since the COVID-era, but I know there's still a challenge to get both the solar components, battery components, but also the equipment needed for interconnection, whether that be long-lead-time transformers, or breakers, or that type of thing. Those are still in place.

And, lastly, we've discussed this, too. The difference in the timelines that it takes to build a solar facility and that it might take to make the necessary improvements to the transmission system to allow for the interconnection and the delivery of that energy to our customers.

So that's not an exhaustive list, but those are some of the headlines, that are -- some of the challenges that we've been seeing through our utility-scale procurements.

Q. Okay. Thank you. So in light of these challenges, including changing regulatory policies, and tariffs and taxes, would the company be open to considering further enhancements to the procurement process and corresponding PPAs that would provide more flexibility in the face of regulatory uncertainty, and thus allow more developers to participate in the RFPs?

A. (Witness Mallard) What the company has put forth is a pretty extensive list of proposed enhancements to the RFP process, with that exact goal, to allow more flexibility, to allow more adaptability through the ability for expanded COD ranges and flexible CODs, through the ability to extend the RFP process.

And so the details of exactly how those improvements will be proposed and implemented will happen through the RFP process. That process, Commissioners, as you know, allows for input from developers, from solar stakeholders, and that would be the opportunity for the solar market to provide additional feedback into the process as we finalize exactly what those final RFP enhancements look like.

Q. Okay. Thank you.

And does the current RFP PPA allow changes in law or tariffs to be taken into account? For instance, if the legal grounds change underneath the project, does the company have the ability to renegotiate or amend the PPA with developers to accommodate changes in law? Like a lot of contracts have, you know, a changes-in-law provision?

A. (Witness Mallard) Yeah. There's not a specific change in law. There's a regulatory out. There's also force majeure language that are in our PPAs at this point. There's not a specific change in law provision.

Q. Okay. And do you know, would the developers have to pay penalties under the current provisions to exit as a result of a change in law?

A. (Witness Mallard) If there was a -- a developer certainly has -- there's certainly remedies in our current purchase power agreements that hold the developers accountable for the terms and conditions of the PPAs in which they enter.

Q. Okay. And would the company consider

including a provision of future PPAs that would allow more developer flexibility for qualifying changes in law?

A. (Witness Mallard) I think the company is always open to feedback from market participants and to be informed by the current conditions in the marketplace. So we're open -- again, we're committed to the success of these RFPs. I'll mention again the -- it's really a balance.

We want to be as flexible as we can, but the certainty of the RFP, the process, the timeline, and bidders knowing exactly the requirements are of the RFP they're bidding in, that's also important. So we always want to balance having an RFP that is predictable and reliable with the ability to be adaptive to changing market conditions.

Q. Okay. Thank you.

So just one more question, and I'm not sure if you can necessarily answer this now, but just in case. So on page 86 of the main IRP document, it states that Georgia Power expects to announce the results of the CARES 2023 RFP in Q1 of this year. And was just wondering if you could provide any clarification on the timing of when that announcement would be?

A. (Witness Mallard) Yeah, I can't. I'm going to respectfully decline to offer any insight into the ongoing CARES utility-scale RFP.

MR. COX: Okay. Thank you. So that's all the questions we have for this panel, and also SREA will not have any questions for the next panel, but thank you for your time.

MR. MALLARD: Thank you.

CHAIRMAN SHAW: Okay. Thank you.

Department of defense.

(No response.)

CHAIRMAN SHAW: Walmart.

CROSS-EXAMINATION

BY MS. EATON:

Q. Smile, you have reached the end. We appreciate your time and actually your willingness to hear feedback from your customers about, you know, these renewable projects that not just meets sustainability goals, but are really just good in general practices. So I'll be brief with just a few follow-ups.

In your direct, on page 37, you talk about the NOI process for the CARES program --

A. (Witness Mallard) Yes.

Q. And you mention, you know, two pricing options. There are subscription terms of 10 to 30 years. Are the subscription terms determined by the customer, the number of years?

A. (Witness Mallard) Yes. The customer chooses the subscription terms. Now, the subscription terms are informed by the purchase power agreement that they're subscribing to. So we allow up to 30 years and so we allow the subscription terms to go from 10 to 30 in 5-year increments and at the customer's discretion.

Q. And what do you mean, "in 5-year increments," what does that mean?

A. (Witness Mallard) So it would either be a 10, a 15, a 20, a 25 or a 30. We do not offer all available integers in between for subscription terms.

Q. Got it. Got it. Just making sure.

And that 10- to 30-year subscription term does apply to the two pricing options; correct?

A. (Witness Mallard) Yes. That's correct.

Q. Then in that same section you say, "The credit will be modified to add reimbursement thresholds."

How is that going to be done?

A. (Witness Mallard) We don't have the details worked out yet, but the concept of the reimbursement threshold is to limit the amount of the credit that the customer could receive, the amount of the energy credit the customer will receive through the subscription, and that will be done in a way to minimize the risk of negative impact on nonparticipating customers. We'll do that in a way that still preserves benefits for the subscribing customer and strikes a balance between the allocation of those benefits between subscribers and nonsubscribers.

Q. Okay. And would it be something akin to capping their bill credit so it doesn't exceed the subscription paid or something like that?

A. (Witness Mallard) It could be something like that. There could be a cap. There could be a collar. You could have sort of a dead band where the -- as long as the credit was close to what the projection was, it could just operate. If it got outside of that band, it could -- that could create a sharing or a cap situation.

We've also thought about just discounting overall the amount of the credit, and some other options are on the table. We definitely would work closely with staff, stakeholders, interested customers, as we develop that methodology and put that into the CARES filing for Commission approval.

Q. Sure. And I want to make sure I understood which program you were talking about. Yesterday, one of you said, "There will be a program-specific docket opened after utility-scale RFP, and the cluster study process." Was that for this CARES program that we've just been speaking of, or is that for the CARES DG subscription program?

A. (Witness Mallard) So both of those programs will need to be approved, whether that's one filing together, or whether there are two separate filings. It's still TBD, but all of the subscription program enhancements will need to be approved by the Commission. There will be associated tariff and program participation provisions. I would -- I would guesstimate that it will be two separate filings, but it could all be done together in a single filing. More to come at the conclusion of the IRP.

Q. Okay. Do you have any sort ballpark on that timing, like next year or later than that?

A. (Witness Mallard) Yeah. Well, we're going to hustle as fast as we can. I would hope to get the filings together in the second half of this year, with approval to potentially be next year. But all of that is TBD, and some of it depends on the outcome of the program, how much the program is maybe modified through this process.

And, again, the participation part of the program is dependent on the RFP that's going to supply it. And so really it's the RFP timelines that need to get settled first, and then the participation timelines would be pursuant to those procurements.

Q. And you're talking about the RFP that is to go out in July of this year?

A. (Witness Mallard) No. We're really talking about future RFPs after -- that are approved as part of the '25 IRP. So that would be the '26 and '27 DG RFPs and the 2026 utility-scale RFP as proposed.

Q. Okay. At this point, based on your work with your customers, commercial-industrial customers, do you expect the subscriptions for your CARES DG program to exceed those megawatts, the 50 megawatts each?

A. (Witness Mallard) It's really hard to predict. A lot of it is going to depend on the price that the market delivers in the DG RFP. We definitely have seen customers that are more sensitive, have sort of less price elasticity than others. There's a point in which that price is going to be higher than what the projected credit is going to be, and the customers are not going to participate.

But I do expect there to be some interest, it's just hard to predict. We've already been told that there is interest, through part of this feedback process, through direct feedback from Walmart themselves.

So we had a couple of sessions, and some of the most astute feedback and observation that we get is from Steve Chriss of Walmart, and so this concept has been run by a lot of customers.

In concept, customers like it and support it, but it just depends on what the economic proposition turns out to be as to how many customers will end up signing up.

Q. Sure. And I'm not really clear on what happens to customers who have requested subscriptions, but then the procurement is maxed out, like, is there -- how would that queue be handled, or, you know, how, would you notify customers that are in that queue, that sort of process?

A. (Witness Mallard) Yeah. So a few things. First of all, we're now introducing the concept where we can go and procure additional resources beyond the initial target. And so if there's additional unmet customer need, then the second -- the buy-down part, the price refresh part would come into play, and then the extended RFP as well, that would allow customers to drive the procurement of additional resources. Again, if that value proposition is something that they're interested in. If they're willing and able to fund those resources.

And so the details of how the original NOI will work, how additional resources are made available, either through the second part or the second phase, all that still needs to be determined, but we'll definitely work closely with all the stakeholders, and especially the customers who are interested in subscribing, as we work out those details.

Q. Sure. And that would be also be part of your filing, which would be a standalone docket, whether it's the DG RFP or -- I mean, the CARES DG with the CARES program, independent dockets or one big docket?

A. (Witness Mallard) I'm not allowed to offer a legal opinion.

Q. Okay. One last point is, I believe, Ms. Goff, you were asked some questions about your direct testimony on page 13 related to industrials participating in the DSM. And I believe you said earlier that the company recognizes there's no need for utility programs to incent the energy efficiency or DSM for industrials because they're already doing that sort of thing on their own.

I think the last, one of the last gentlemen kind of alluded to this a little bit. And he also talked very favorably about your work with national account managers. But wouldn't you agree that there are also sophisticated commercial customers who also have implemented their own energy efficiency and DSM measures on their own, at their own costs?

A. (Witness Goff) That may be true. The distinction there, though, is that industrial customers, we treat as a class. So as a class of customers through

many, many IRPs now, the policy of this Commission is that industrial customers are not included in the DSM programs supplied by the company to do, kind of, customer-specific opt-outs within the commercial class. That's really just not cost effective for us to implement. So it's the distinction between a class of customers versus trying to distinguish individual customers within that overall class. So that's the difference there.

Q.   Primarily because in Georgia they don't allow commercial customers to opt out?

A.   (Witness Goff) That's right. It's just not an effective way to implement the programs. We offer programs that all residential and all commercial customers can participate in, and so those costs go through the DSM riders for the residential and commercial customers. Industrial customers as a group have not been included, based on past precedent.

A.   (Witness Phillips) And if the customers were allowed to opt out, what that would do is put even more upward pressure on rates for nonparticipants.

MS. EATON: All right. Thank you. That's all I have.

CHAIRMAN SHAW: Thank you.

Redirect.

MS. PRYOR: No redirect. Thank you.

CHAIRMAN SHAW: All right. Thank you.

Panel, thanks for your thoroughness and your time. You can be excused. We'll take a ten-minute break, and we will begin with the next panel. But like I said earlier, we'll go until somewhere in that 5:30, 5:45, 6:00 range, take a break and keep going. We will come back at 4:40.

(Whereupon a break was taken.)

CHAIRMAN SHAW: Thanks for a little break. I hope everybody got enough break. It's time to get back to work. It's time to swear in the next and final, third panel.

Mr. Marzo, if you want to swear in your panel.

MR. MARZO: Thank you, Chair Shaw. We'd like to call the panel of Ms. McNelly and Mr. Mitchell to the stand. If you both would raise your right hand.

With your permission, Mr. Chair, I'll swear them in.

CHAIRMAN SHAW: Yes, sir.

Thereupon,

JENNIFER S. MCNELLY,
ROBERT W. MITCHELL, III,
having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. MARZO:

Q. Ms. McNelly, would you please start by stating your full name, your employer, and your responsibilities for the record?

A. (Witness McNelly) My name is Jennifer Suzanne McNelly. I'm the vice president of Environmental Affairs at Georgia Power, and my team is responsible for the environmental compliance for business operations throughout the state, as well the development of and the implementation of the environmental compliance strategy.

Q. Thank you.

Mr. Mitchell, would you do the same?

A. (Witness Mitchell) Yes. My name is Brett Mitchell. I am the director for Georgia Power's Coal Combustion Residual Program management office, and my team is responsible for the management and closure of Georgia Power's ash ponds and landfills.

Q. Thank you.

Ms. McNelly, on February 28th of this year, did you prefile or cause to be prefiled 31 pages of direct testimony in question-and-answer format in this case?

A. (Witness McNelly) Yes.

Q. Are there any corrections you need to make to your prefiled direct testimony?

A. (Witness McNelly) Not a correction, but an update. Georgia EPD has issued an additional CCR permit, making that total 18 permits instead of 17 permits for the CCR program.

Q. Thank you, Ms. McNelly.

If I were to ask you the same questions today under oath, would your answers be the same as set forth in your prefiled testimony, with that correction?

A. (Witness McNelly) Yes.

MR. MARZO: Mr. Chair, the court reporter has been provided a copy of the prefiled direct testimony. Now, I ask that the direct testimony of this panel be copied into the record as if given orally here today.

CHAIRMAN SHAW: So marked.

(Whereupon, the prefiled direct testimony of Jennifer S. McNelly and Robert W. Mitchell III follows:)

STATE OF GEORGIA

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:

Georgia Power Company's	)	**Docket No. 56002**
2025 Integrated Resource Plan	)	

Georgia Power Company's	)	**Docket No. 56003**
2025 Application for the Certification,	)	
Decertification, and Amended	)	
Demand-Side Management Plan	)	

DIRECT TESTIMONY OF

JENNIFER S. MCNELLY AND ROBERT W. MITCHELL, III

FEBRUARY 28, 2025

DIRECT TESTIMONY OF
JENNIFER S. MCNELLY AND ROBERT W. MITCHELL, III

IN SUPPORT OF GEORGIA POWER COMPANY'S
2025 INTEGRATED RESOURCE PLAN
DOCKET NO. 56002

AND

APPLICATION FOR THE CERTIFICATION, DECERTIFICATION, AND AMENDED DEMAND SIDE MANAGEMENT PLAN
DOCKET NO. 56003

I. INTRODUCTION

Q. PLEASE STATE YOUR NAMES, TITLES, AND BUSINESS ADDRESSES.

A. My name is Jennifer S. McNelly. I am the Vice President of Environmental Affairs for Georgia Power Company ("Georgia Power" or the "Company"). My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

A. My name is Robert W. ("Brett") Mitchell, III. I am the Director of the Coal Combustion Residuals ("CCR") Program Management Office for Georgia Power. My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

Q. MS. MCNELLY, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of Alabama with a Bachelor of Science in Chemical Engineering. I also completed a Master of Business Administration degree from the University of Alabama at Birmingham.

I have worked in a variety of roles within the Southern Company footprint since beginning my career in 2001 as a cooperative education student with Southern

Nuclear Company. In 2005, I began as an engineer at Southern Company Services ("SCS") where I was responsible for leading process design for large capital environmental projects. From 2011 to 2018, I worked in various leadership roles within Generation for both Alabama Power and Georgia Power, including maintenance and operations team leader roles at Plant Miller; the Assistant to the Senior Production Officer and Vice President of Generation; the Operations Department Assistant Manager at Plant Bowen; the Engineering, Compliance, and Support Manager at Plant McDonough; and the Maintenance Manager at Plant Bowen. In 2018, I transitioned to the Environmental Solutions Water Program Manager role at SCS. As Water Program Manager, I supervised ash process personnel and activities and participated in environmental strategy budget inputs, water treatment project processes, fleet-wide ash pond dewatering treatment, and vendor partnerships. In 2020, I served as the Director of Environmental Solutions at SCS. In that role, I led the Environmental Solutions Department, comprised of the Air Program, Water Program, Land Strategy, Earth Sciences & Environmental Engineering, and Geotechnical/Fossil Dam Safety.

I currently serve as the Vice President of Environmental Affairs at Georgia Power and have been in this role since March 2023. In this role I am responsible for the overall environmental compliance of business operations at the Company and regulatory obligations related to compliance with existing and anticipated environmental laws and regulations. This responsibility includes the creation and implementation of the Company's Environmental Compliance Strategy ("ECS") and supporting processes.

Q. MS. MCNELLY, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION?

A. No.

Q. MR. MITCHELL, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of Georgia with a degree in Environmental Health Sciences. I have worked at Southern Company since 1995, when I began my career at Georgia Power as an environmental specialist responsible for managing environmental remediation projects across the state. In 2007, I moved to a supervisory role overseeing all Georgia Power remediation and waste compliance activities, including assessing, selecting, and implementing site-specific remediation methods and technologies, overseeing environmental emergency response activities, permitting landfills to support operations and the installation of environmental controls, and managing special wastes to ensure proper disposal. I transitioned to Southern Company from 2014 to 2016 as the Conceptual Engineering Manager responsible for strategy budget inputs, and developing strategies to address land and water related environmental requirements for all operating companies, including for the CCR Rule. In 2016, I returned to Georgia Power to manage the team leading the company's CCR compliance strategy development and implementation, including for the federal and newly finalized state CCR rule and permitting program. During this time, I was also responsible for managing Georgia Power's ongoing remediation and waste compliance programs. In 2020, I served as CCR Portfolio General Manager responsible for Georgia Power's CCR program strategy and execution. During this time, I was also responsible for standing up a Program Management Office and associated processes to proactively manage the large-scale and decades-long CCR program.

Currently, as the Director of the CCR Program Management Office for Georgia Power, I am responsible for the successful execution, governance, oversight, strategy, regulatory processes, and overall management of Georgia Power's CCR Program for ash pond and landfill closure projects. This includes direct oversight and management of all aspects of the closure of the Company's ash ponds, construction, operations, and closure of the CCR landfills at 12 current and former generation plant sites.

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

A. No.

Q. WHAT IS THE PURPOSE OF THE PANEL'S TESTIMONY?

A. The purpose of our testimony is to support the Company's ECS filed as part of Georgia Power's 2025 Integrated Resource Plan ("IRP"). We address specific aspects of the ECS, including recent regulatory and strategy updates related to greenhouse gas ("GHG") emissions limitations on fossil-based generation, Mercury and Air Toxics Standards ("MATS") revisions, Effluent Limitations Guidelines ("ELG") rules for scrubber wastewater and combustion residual leachate ("CRL"), and the state and federal CCR rules. In addition, our testimony discusses the Company's management of ash pond closure plans approved in the 2019 and 2022 IRPs, beneficial use of CCR, and Georgia Power's approach to planning for carbon pressures on its generating fleet.

Q. PLEASE SUMMARIZE THE PANEL'S TESTIMONY.

A. Georgia Power's ECS describes the comprehensive strategy to comply with all applicable state and federal environmental laws and regulations through the implementation of cost-effective environmental controls and actions. The strategy enables Georgia Power to develop a flexible and adaptive plan to ensure continued compliance and resource planning optionality.

Georgia Power continues to manage numerous regulatory requirements associated with its generation plants. Revisions to the Company's 2025 ECS reflect changes to environmental regulations finalized since the Georgia Public Service Commission ("Commission") previously approved the Company's ECS in the 2022

IRP. As such, the Company is focused on the investment and actions needed to comply with recent revisions to several key environmental regulations, including United States Environmental Protection Agency's ("EPA") 111 GHG Rules and the 2024 ELG Rule.

Notwithstanding pending legal challenges to each of the main environmental rules discussed herein, the Company must move forward on compliance actions with near-term compliance deadlines approaching. Further, since this uncertainty is likely to continue for the foreseeable future, it is imperative that the Company continue to take a long-term approach to planning decisions, building in appropriate flexibility and resource planning optionality, to ensure compliance readiness while continuing to meet customer needs.

For example, the 111 GHG Rule sets forth designated compliance pathways for existing steam generating units, with options to retire, install and operate carbon capture and sequestration ("CCS") technology, or co-fire coal with natural gas. It sets forth designated compliance pathways for new combustion turbines with options to install CCS or operate at less than 40% annual capacity factor. As discussed in the IRP Main Document, the ECS, and the Direct Testimony of Witnesses Grubb, Hubbert, Looney, Robinson, and Valle, the Company assumes all new combined cycle units will be limited to no more than a 40% annual capacity factor and has elected the co-fire compliance pathway for Plants Bowen and Scherer.

Further, EPA's 2024 ELG Rule requires the installation of additional wastewater treatment controls at current and former coal-fired power plants even though implementation of the 2020 ELG Rule is still in progress. The 2024 ELG Rule requires Zero Liquid Discharge ("ZLD") by December 31, 2029, for scrubber wastewater and leachate collected from on-site landfills at operational plants and additional treatment requirements for leachate and legacy water at retired sites. While ELG compliance plans at Plant Scherer are less impacted—due to the selection of the Voluntary Incentives Program ("VIP") compliance option for scrubber wastewater that remains unchanged from the 2020 ELG Rule—the new ZLD requirement presents a significant compliance challenge for Plant Bowen, where additional controls must be designed, engineered, and installed to comply.

Finally, the Company continues to make progress on its CCR compliance strategy to permanently close CCR ash ponds and landfills under the oversight of the Georgia Environmental Protection Division's ("EPD") federally approved CCR program. The Company continues to evaluate opportunities to refine and optimize its closure plans and pursue opportunities to create value through beneficial use.

The 2025 ECS describes the Company's plans to comply with environmental laws and regulations by implementing a strategic and flexible plan that installs cost-effective and protective controls consistent with the Company's commitment to supply clean, safe, reliable, and affordable energy to its customers. The Company requests Commission approval of the ECS and the related capital, operations and maintenance ("O&M"), and CCR asset retirement obligation ("ARO") costs, and associated measures taken to comply with government-imposed environmental mandates.

Q. HOW IS THE REST OF YOUR TESTIMONY ORGANIZED?

A. The remainder of our testimony is organized as follows:

- <u>Section II</u> provides an overview of the Company's Environmental Compliance Strategy.
- <u>Section III</u> discusses recent changes to applicable environmental compliance regulations.
- <u>Section IV</u> discusses the Company's CCR compliance strategy.
- <u>Section V</u> details Georgia Power's beneficial use activities.
- <u>Section VI</u> discusses climate and carbon pressures.

II. ENVIRONMENTAL COMPLIANCE OVERVIEW

Q. WHAT IS THE ENVIRONMENTAL COMPLIANCE STRATEGY?

A. In accordance with Commission Rule 515-3-4-.04(1)(c), Georgia Power's ECS includes a detailed overview of the applicable current and proposed environmental laws and regulations for its electric generation plants as well as the Company's comprehensive strategy for complying with those requirements. The Company's annual ECS development process considers plant-specific compliance options and evaluates those options based on technology availability; cost; schedule; and impact to plant operations, the environment, and surrounding communities. This approach provides the necessary flexibility to develop and refine Georgia Power's ECS in today's dynamic regulatory compliance environment, assuring compliance with robust control plans that are in the best interests of customers.

Q. PLEASE DESCRIBE THE ENVIRONMENTAL REGULATORY FRAMEWORK APPLICABLE TO GEORGIA POWER AND HOW THE ECS ENSURES COMPLIANCE WITH THAT FRAMEWORK.

A. Georgia Power's ECS contains actions necessary to comply with federal and state requirements of multiple regulators, including the EPA, the Georgia EPD, and the Commission. The EPA creates, maintains, and enforces national standards under a variety of environmental laws and establishes these standards through the development of federal regulations. The Georgia EPD is the implementing body for both federal and state laws through rules, policies, and permits to protect human health and the environment. Finally, the Commission reviews the Company's ECS, along with the cost estimates to implement that strategy, and determines if the strategy and associated costs are reasonable.

The annual development of the ECS, in coordination with the triennial IRP process, provides an opportunity for the Company to respond to changing environmental regulations and incorporate new information as it becomes available over the course of Georgia Power's long-term planning process. While the strategy itself will necessarily evolve over time to address changes in applicable state and federal regulations, the purpose of the ECS process is and has always been to assure compliance with all environmental requirements, produce cost-effective compliance solutions that minimize the impact to customers, and to maintain the necessary flexibility to adjust to the dynamic nature of environmental regulations.

Q. WHAT ARE SOME OF THE COMPANY'S MILESTONE ACHIEVEMENTS WITH REGARD TO ENVIRONMENTAL COMPLIANCE?

A. Georgia Power is committed to meeting its environmental compliance obligations while also providing customers with clean, safe, reliable, and affordable energy. For example, since 1990, the Company has reduced nitrogen oxides ("NO_x") and sulfur dioxide ("SO_2") emissions from its generating fleet by more than 95% and 99%, respectively. Additionally, mercury emissions have decreased by more than 98% and carbon dioxide ("CO_2") emissions by more than 60% since 2007. Further, water withdrawals have decreased by 90% since 2003 with the transition of the generation fleet.

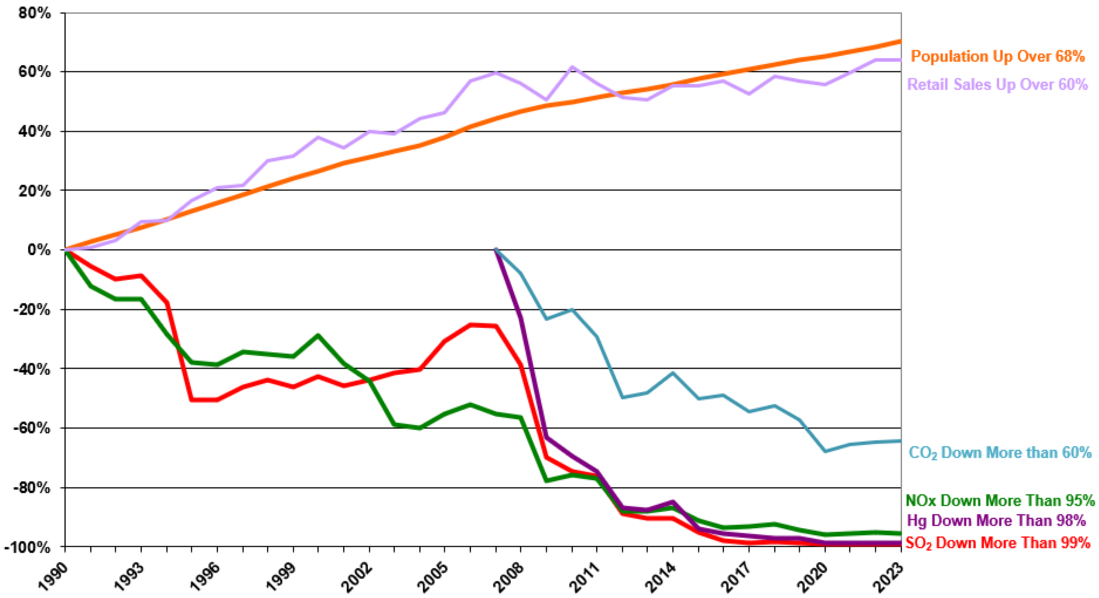

FIGURE 1 – Georgia Power Emission Trends

Requirements related to wastewater discharge and ash pond closures have resulted in the installation of 16 wastewater treatment systems and dry or zero discharge ash handling equipment for coal facilities. In compliance with the federal and state CCR rules, Georgia Power has advanced closure construction activities in various stages at its 29 ash ponds, which includes conducting preliminary sitework, design, dewatering, and closure construction.

Additionally, the Company continues to recycle, on average, more than 85% of the CCR generated from plant operations for beneficial use, which significantly reduces waste streams for the benefit of customers and the environment. As a part of ash pond closure, up to nineteen million tons of ash are anticipated to be harvested, processed, and removed from sites for beneficial use throughout the multi-year closure timeframe.

Q. PLEASE DESCRIBE GEORGIA POWER'S 2025 ENVIRONMENTAL COMPLIANCE STRATEGY.

A. Georgia Power's 2025 ECS sets forth a comprehensive strategy outlining the Company's cost-effective plans to comply with all applicable environmental requirements, including the following four rules finalized by EPA in the spring of 2024 that impose new requirements on utilities in the power sector: (a) GHG emissions limitations pursuant to the Clean Air Act, Section 111 ("111 GHG Rules"); (b) revised MATS; (c) revised and supplemental ELGs; and (d) CCR rule amendments through the Legacy CCR Surface Impoundments Rule ("Legacy Rule"). Each of these four environmental regulations are discussed in more detail below.

Q. IS THERE REGULATORY UNCERTAINTY THAT COULD AFFECT THE 2025 ENVIRONMENTAL COMPLIANCE STRATEGY?

A. Yes. Georgia Power's 2025 ECS accounts for uncertainty in legal and regulatory outcomes related to the new rules finalized by EPA in 2024. While all four of the new rules have been legally challenged, in each case the respective court declined to put the rule requirements on hold. As such, all the rules remain in effect with compliance deadlines quicky approaching. The Company's compliance strategy for these new rules ensures environmental mandates can be met while remaining ready to adapt to future litigation or regulatory developments. The final outcomes of ongoing litigation, potential executive actions, and potential subsequent rulemaking may take years to resolve, and this uncertainty requires that Georgia Power work towards compliance with final regulations, as implemented by EPD through its permits and state plan, while staying flexible for various outcomes, including the suspension of some or all rule requirements. Therefore, the Company will continue its current compliance strategy until there is more certainty on the ultimate outcome for each challenged regulation, at which time the Company will reevaluate and adapt the ECS as appropriate.

The Company's "all of the above" approach to supply-side, demand-side, and transmission planning is critical to manage the uncertainty presented by environmental mandates both now and in the future, especially during a time of high projected load growth. The goal of the Company's strategy is to ensure compliance with all applicable state and federal requirements and provide cost-effective solutions for the generating fleet that are in the best interests of customers, while preserving the flexibility of the approaches taken given the dynamic regulatory environment.

III. CHANGES TO ENVIRONMENTAL COMPLIANCE REGULATIONS SINCE 2022 AFFECTING THE ECS

A. 111 GHG Rules

Q. PLEASE DESCRIBE THE 111 GHG RULES AND WHAT THEY REQUIRE.

A. The EPA's 111 GHG Rules seek to limit GHG emissions from power plants, with the 2024 rules specifically focused on new gas turbines and existing coal plants. As a result of the new requirements, by 2032 new combined-cycle units without CCS must limit their annual capacity factor to 40%. New simple-cycle combustion turbines ("CTs") must limit their annual capacity factors to no more than 40% and potentially as low as 20%. On the other hand, existing coal-fired generation units would be subject to standards set in a forthcoming state plan. EPA's Rule outlines three compliance pathways for existing coal units to states: (1) retirement by January 1, 2032; (2) add 90% CCS by January 1, 2032; or (3) 40% gas co-firing by January 1, 2030, with retirement by January 1, 2039. State plans are due May 2026 and are subject to EPA review and approval. The 111 GHG Rules permit states to deviate from these pathways if justified and needed.

Q. WHAT IS THE COMPANY'S COMPLIANCE STRATEGY FOR THE 111 GHG RULES?

A. Notwithstanding pending legal challenges to the 111 GHG Rules, Georgia Power must evaluate these regulations as currently finalized and develop compliance strategies. Certain affected generating units, including new CTs (Plant Yates Units 8-10) and existing steam generating units—Plant Yates Units 6-7 and Plant Gaston Units 1-4—are expected to be able to continue operating as planned and without significant additional cost or constraint under the new requirements. However, Plant Bowen Units 1-4 and Plant Scherer Units 1-3, comprising over 4,000 megawatts of capacity, are significantly impacted under the current 111 GHG Rules.

Two of the three pathways for coal units outlined in EPA's 111 GHG Rules, retire by January 1, 2032, or install and operate CCS, are not only costly but also impractical. Georgia Power's elected compliance strategy for all seven existing coal units is to pursue co-firing natural gas beginning January 1, 2030, or as soon as feasible, with retirement of these units by January 1, 2039. This decision is supported by the Company's planning tools such as Unit Retirement Studies, included in Technical Appendix 1, and other scenario analyses, which indicate that co-firing is more cost effective, poses lower risk, and is more technically feasible than other pathways, including retirement.

Q. WHAT COMPANY UNITS ARE SUBJECT TO A STATE PLAN AND HOW WILL FINAL STANDARDS BE DEVELOPED?

A. Plant Yates Units 6-7, Plant Bowen Units 1-4, and Plant Scherer Units 1-3 are subject to the state-specific compliance plan to be prepared by Georgia EPD and submitted to EPA for approval. In the plan, Georgia EPD will establish performance standards for each of these generating units based on EPA's guidelines, which contain "presumptively approvable" standards for subcategories of existing coal and gas-steam resources. However, EPD will not submit its plan until May 2026, and approval from EPA is not expected to occur until July 2027. Plant Gaston Units 1-4, which are located in Alabama, will similarly be subject to a state plan developed by the Alabama Department of Environmental Management. Because states have not yet developed the plans to establish the standards, and those plans will be subject to EPA review and approval, significant uncertainty remains regarding the potential impact of the 111 GHG Rules if they remain in effect.

For Plant Bowen and Plant Scherer, the presumptively approvable emissions standard based on 40% natural gas co-firing and the January 1, 2030, compliance date requires further analysis, which is ongoing. Both the emissions standard and compliance date will be finalized through engagement with Georgia EPD during the state plan process, contingent on approval by EPA. The final emissions standards and compliance dates may differ from those in EPA's guidelines based on the consideration of Remaining Useful Life and Other Factors ("RULOF"). In considering RULOF, the state can establish a standard or compliance date that differs from EPA guidelines as needed to account for a facility's individual circumstances. Georgia Power is in the process of conducting engineering studies to evaluate technical considerations and operational impacts of co-firing natural gas for the generating units at Plant Bowen and Plant Scherer. These studies will be critical to inform the state plan development process.

Q. HAS THE COMPANY PARTICIPATED IN LEGAL CHALLENGES TO THE 111 GHG RULES?

A. Yes. A multi-state coalition, including Georgia, as well as numerous industry and interest groups have filed legal challenges to the 111 GHG Rules before the U.S. Court of Appeals for the D.C. Circuit. Georgia Power's parent company, Southern Company, is a member of the Electric Generators for a Sensible Transition, one of the industry groups that filed a legal challenge. In July 2024, the D.C. Circuit declined to stay the rules, which resulted in emergency stay petitions at the U.S. Supreme Court. In October, the Supreme Court denied the request for emergency stay. The D.C. Circuit held oral arguments on the challenge on December 6, 2024.

On February 19, 2025, the court granted EPA's request to pause the litigation for 60 days while the agency reviews the rule. Notwithstanding the ongoing litigation, the 111 GHG Rules as finalized in 2024 are the current rules in effect and must be considered by Georgia Power in its planning process.

Q. HOW DOES THE ECS PROCESS ACCOUNT FOR POTENTIAL CHANGES TO THE 111 GHG RULES OR LEGAL UNCERTAINTY?

A. As discussed above, the ECS is an iterative process that is designed to provide the Company with a flexible and responsive compliance strategy for applicable environmental rules and regulations. Georgia Power continues to monitor and evaluate developments in the 111 GHG Rules. As a part of Georgia Power's ECS, the 111 GHG Rules strategy for Plant Bowen and Plant Scherer is to pursue the natural gas co-firing compliance pathway, starting with engaging engineering firms to perform boiler studies to determine potential designs for adding natural gas co-firing capability. Georgia Power will also engage with Georgia EPD and other stakeholders on the feasible compliance timeline and requirements that will minimize the impacts to reliability and affordability for customers. While these activities can be paused or slowed down in the event of a future legal decision or policy change, waiting to start these activities could have profound consequences for resource planning in the event the rules are upheld.

B. 2024 Mercury and Air Toxics Standards Revisions

Q. WHAT ARE THE MERCURY AND AIR TOXICS STANDARDS?

A. Finalized in 2012, the EPA's MATS rule is a technology-based rule that regulates hazardous air pollutants ("HAP"), including mercury, acid gases, and metallic HAP (via particulate matter emissions as a surrogate) from coal- and oil-fired electric generating units. Under the Clean Air Act, EPA is required to review and update the standards as necessary on a periodic basis.

Q. PLEASE DESCRIBE THE RECENT MATS REVISIONS.

A. In 2024, EPA finalized MATS revisions that significantly lowered the particulate matter limit applicable to coal-fired power plants. The revisions also require utilities to demonstrate compliance with the revised limit through continuous emissions monitoring as opposed to stack testing, which was allowed under the prior standards. The Company must comply with the MATS revisions by July 2027.

Q. WHAT IS THE COMPANY'S MATS COMPLIANCE STRATEGY?

A. Georgia Power has complied with MATS for about 10 years. Currently, the Company utilizes stack testing to confirm its units are compliant with particulate matter emissions limitations, which consistently shows the Company's coal-fired generating units (Plants Bowen and Scherer) are emitting at levels less than the more stringent limit finalized in the 2024 MATS revision. Thus, the Company does not anticipate the installation of additional controls to comply with the revised standards. Compliance will require the addition of new particulate matter continuous emissions monitoring for each of Plant Bowen Units 1-4 and Plant Scherer Units 1-3.

C. 2024 ELG Rule

Q. PLEASE PROVIDE AN OVERVIEW OF THE PREVIOUSLY APPLICABLE ELG RULES.

A. In November 2015, EPA updated its steam electric ELGs for the first time since 1982 (the "2015 ELGs"). The 2015 ELGs established technology-based standards affecting coal ash management and set stringent limits for scrubber wastewater. The 2015 ELGs established a VIP for scrubber wastewater, which provided a later compliance deadline for plants able to meet even more stringent scrubber wastewater limits based on advanced evaporation technology.

Since the issuance of the 2015 ELGs, the requirements have changed multiple times either by court action or EPA rule changes. In October 2020, EPA finalized revisions to the ELGs (the "2020 ELG Rule"), which had important implications for the Company's strategy on scrubber wastewater treatment. For scrubber wastewater, the 2020 ELG Rule established standards based on wastewater treatment technology consisting of a combination of chemical precipitation followed by biological treatment (also referred to as physical-chemical-biological treatment or "phys-chem-bio") with a compliance deadline of December 31, 2025. Compared to the 2015 ELGs, the scrubber wastewater limits were slightly less stringent for certain constituents and significantly more stringent for others. The 2020 ELG Rule also revised the VIP subcategory for scrubber wastewater to provide a compliance deadline of December 31, 2028, for plants to achieve more stringent ELGs based on membrane filtration and established a pathway to opt into a subcategory that requires permanent cessation of coal combustion by December 31, 2028. After challenges to the 2020 ELG Rule by environmental groups, the EPA announced in 2021 that it would initiate a new rulemaking but stated that permitting authorities should continue implementation of the 2020 ELG Rule.

Q. PLEASE DESCRIBE THE 2024 ELG RULE.

A. On May 9, 2024, EPA finalized its "Supplemental Steam Electric Effluent Limitations Guidelines and Standards for the Electric Power Generating Point Source Category (the "2024 ELG Rule"). The 2024 ELG Rule adds additional requirements to the ELG rules described above and sets forth more stringent compliance pathways for the Company's scrubber wastewater and CRL. Most significantly, the 2024 ELG Rule established a ZLD requirement for scrubber wastewater and CRL from the Company's coal-fired generating units with compliance required by no later than December 31, 2029. The VIP and cessation of coal combustion subcategories remain unchanged from the 2020 ELG Rule. In the 2024 Rule, EPA also maintains the 2020 ELG Rule scrubber wastewater requirements and the December 31, 2025, deadline for phys-chem-bio treatment until the applicability dates of the new zero-discharge limitations are met.

The 2024 ELG Rule also adds a new subcategory option for electric generation units that are permanently ceasing coal combustion by 2034 and preserves the VIP compliance option. The 2024 ELG Rule also requires treatment of CRL at facilities that no longer burn coal.

Q. HAS GEORGIA POWER UPDATED ITS ECS WITH REGARDS TO THE 2020 ELG RULE?

A. Yes. Since the initial 2015 ELGs publication in November 2015, the numerous changes to the rule have made it necessary for the Company to maximize the flexibility of the environmental compliance strategy process to revise and optimize plans with each rule iteration and to continue studying evolving technologies, all while meeting compliance obligations currently in effect.

In light of the continuing increase to the Company's projected load forecast and the magnitude of capacity needs in 2028 and beyond, as discussed in the Direct Testimony of Witnesses Grubb, Hubbert, Looney, Robinson, and Valle, the Company is making a formal recommendation in this IRP to continue operations for Plant Bowen Units 1-2, as well as extending the operation of Plant Scherer Unit 3 and Plant Gaston Units 1-4 beyond the 2028 retirement dates approved in the 2022 IRP.

With the continued operation of Plant Bowen Units 1-2 beyond 2028, scrubber wastewater from those units will use the same treatment system currently under construction for Plant Bowen Units 3-4 to comply with the 2020 ELG Rule. For Plant Scherer Units 1-2, the Company considered plant-specific equipment and operational characteristics and selected a membrane-based technology system to meet the VIP compliance subcategory requirements by December 31, 2028. The site-specific water quality and quantity characteristics at Plant Scherer are a unique technical fit that allow the VIP pathway and membrane technology to be cost competitive. If the Commission approves Georgia Power's plan for the continued operation of Plant Scherer Unit 3 beyond 2028, the scrubber wastewater will be treated with the other units. In addition, based on current regulations, the compliance investments required at Plant Gaston Units 1-4 are expected to remain unchanged to continue operation beyond 2028.

Q. HOW DOES THE 2024 ELG RULE CHANGE THE COMPANY'S COMPLIANCE PLANS AT PLANTS BOWEN AND SCHERER?

A. Since the 2024 ELG Rule retained the VIP compliance option, no major change in compliance approach is needed for Plant Scherer for scrubber wastewater treatment. For Plant Bowen, the 2024 ELG Rule creates additional treatment needs. The Company has identified two potentially feasible alternatives:

(1) A membrane-evaporator-crystallizer system was established by EPA in the 2024 ELG Rule as the technology basis for the ZLD limit. The Company has included control assumptions and costs related to installation of a membrane-evaporator-crystallizer treatment system in the 2025 IRP as Plant Bowen's 2024 ELG Rule compliance option.

(2) The Company is also investigating and considering an alternative system that would exclude the membrane system from the first option. Should the alternative treatment system show technical viability and costs comparable to the membrane-evaporator-crystallizer system, the Company will pursue the alternative system.

The benefits of the Company's dual-path evaluation include: (i) the ability to perform further technical feasibility analysis, (ii) the ability to adjust to future regulatory changes, and (iii) the flexibility to install the best technology for the plant-specific scrubber wastewater volumes and characteristics.

In addition to scrubber wastewater, the 2024 ELG Rule requires ZLD of CRL at operational coal-fired facilities. Currently, the Company's plans for CRL treatment at Plants Bowen and Scherer are based on an evaporative process and estimated costs are at a prescreening level of certainty. For facilities that have previously retired coal-fired generation, the 2024 ELG Rule requires EPD to establish site-specific technology-based limits using best professional judgment. Accordingly, the 2024 ELG Rule's requirement for case-by-case technology-based effluent limitations established by the permitting authority will be subject to future permitting actions. Nevertheless, the Company is able to use current treatment technology assumptions and associated costs within the ECS for planning purposes.

Q. IS THERE LEGAL UNCERTAINTY SURROUNDING THE 2024 ELG RULE?

A. Yes. Like the 111 GHG Rules, the 2024 ELG Rule is currently in litigation before the Eighth Circuit Court of Appeals. Southern Company is a member of the Utility Water Act Group, one of the industry groups that is a petitioner on the challenge. Opening briefs were filed in November 2024, and on February 19, 2025, EPA requested that the court pause the litigation proceedings for 60 days. The rule remains in effect while the final outcome of the case is still pending. This means that the Company must continue its plan to achieve compliance with the 2024 ELG Rule and stay on track to complete systems to meet the compliance deadlines in the 2020 ELG Rule, while staying flexible for various legal outcomes.

Q. HOW DOES THE COMPANY'S ELG COMPLIANCE STRATEGY ALLOW FOR FLEXIBILITY TO RESPOND TO FUTURE REGULATORY CHANGES?

A. Georgia Power's ELG strategy benefits customers by providing a balanced plan to comply with existing requirements while maintaining flexibility to select the most appropriate unit-specific compliance options at certain sites. This plan best addresses the continuing uncertainty around the ultimate outcome of the ELG rule by moving forward on implementation of controls to ensure compliance by the required deadlines, while continuing to study wastewater treatment technology where there may be promising alternatives. This strategy provides the Company an ability to adapt to changing regulations while ensuring compliance and reliable operation moving forward.

D. Legacy Rule

Q. WHAT IS CCR?

A. Coal Combustion Residuals, or CCR, are the byproducts produced from burning coal in coal-fired generation plants. As it relates to Georgia Power's operations, CCR includes fly ash, bottom ash, and gypsum. Fly ash and bottom ash are direct byproducts of the coal combustion process, whereas gypsum is the byproduct produced by the flue gas desulfurization process. CCR includes the fly ash, bottom ash, and gypsum produced from the Company's remaining operational coal units as well as the byproducts stored at Georgia Power's retired coal plants.

Q. PLEASE DESCRIBE THE FEDERAL AND STATE REQUIREMENTS FOR CLOSURE OF ASH PONDS AND LANDFILLS.

A. Georgia Power must comply with both the federal and state CCR rules at its ash ponds and CCR landfills. The federal CCR rule was finalized in 2015 (and amended numerous times thereafter) and established national minimum criteria for certain CCR landfills and ash ponds, including location restrictions, design and operating criteria, annual inspections, groundwater monitoring, corrective action, closure requirements and post-closure care, recordkeeping, notification, and internet posting requirements. The federal CCR rule mandates strict regulatory deadlines to complete closure of ash ponds.

The Georgia CCR rule finalized in 2016 adopted the federal CCR rule and additionally requires comprehensive permitting, oversight, and monitoring by EPD for all ash ponds and CCR landfills in the state. Both rules explicitly authorize closure-in-place and closure-by-removal as options for compliance, with each option subject to its own set of closure performance criteria. Neither rule dictates the use of either closure option in a particular instance. In fact, in establishing the federal CCR rule, EPA confirmed that both methods of closure—closure-in-place and closure-by-removal—are equally protective when the relevant performance criteria are properly implemented.

The federal and state CCR rules have both been amended numerous times over the past few years and Georgia Power expects they will continue to be reviewed and updated in the future.

Q. HAVE NEW CCR RULES OR REGULATIONS BEEN FINALIZED SINCE THE 2022 IRP?

A. Yes. On May 8, 2024, EPA issued the Legacy Rule. The Legacy Rule applies certain requirements from the existing CCR regulations as well as new compliance obligations to two categories of newly regulated CCR units: legacy CCR surface impoundments and CCR management units ("CCRMUs").

The Legacy Rule is expected to have limited impact on Georgia Power CCR units that meet the legacy CCR surface impoundments definition. Although previously exempt from federal regulation, Georgia Power's legacy CCR surface impoundments have all been regulated under Georgia EPD's CCR permitting program, previous state landfill permits, and/or state remediation programs. These units were or are being closed under the applicable state program. The finalization of the Legacy Rule, however, subjects these legacy units to duplicative requirements and oversight by both the state and federal agencies. While Georgia's comprehensive CCR, solid waste, and remediation rules have effectively regulated closure of CCR ash ponds and landfills in the state, the EPA's CCR Legacy Rule adds additional requirements.

First, the Legacy Rule defines a new type of CCR unit—CCR management units or CCRMUs. CCRMUs are areas of noncontainerized storage or management of CCR that are not part of an already-regulated CCR unit. The Legacy Rule requires facility evaluations at all current and former coal-fired power plant facilities to identify the potential existence of CCRMUs. This labor-intensive effort is due in two parts, within 21 months and 33 months of the final rule. Any CCRMUs that are identified through the facility evaluations are required to close and undertake groundwater monitoring and corrective action (where required) according to federal CCR rule requirements.

Second, the Legacy Rule definition for legacy CCR surface impoundments includes certain CCR units in Georgia that have been regulated by Georgia EPD. Although the applicability of the new Legacy Rule is not expected to significantly affect Georgia Power's closure plans, the Legacy Rule has the potential to introduce additional compliance timelines and impose additional monitoring requirements that may differ from current plans.

Third, the Legacy Rule codifies new definitions for key terms related to the performance standards for ash ponds that are closed in place. These new definitions for infiltration and liquids largely reflect EPA's new interpretations of these standards, first announced in January 2022, although uncertainty remains in the application of EPA's interpretations on a site-specific basis. In addition, the retroactive applicability of these new definitions has been legally challenged. While the impact of these definitional changes remains unclear pending legal outcomes, Georgia Power's closure-in-place units remain under the purview of the EPA-approved Georgia CCR permit program and include engineering controls designed to enhance groundwater protection.

Q. DOES THE CCR LEGACY RULE DIRECT THE COMPANY TO CHANGE ITS CCR ASH POND CLOSURE STRATEGY?

A. No. Georgia Power's ash pond closure strategy, including for legacy surface impoundments, is designed to comply with both the federal CCR Rule and the Georgia CCR Rule. The Company ceased placement of CCR in all ash ponds in 2019, and the CCR units are in various stages of closure under the oversight of Georgia EPD.

The ECS outlines Georgia Power's plans for complying with the Legacy Rule's administrative reporting requirements, website updates, and facility evaluations with associated reporting in 2026 and 2027, to identify the presence or absence of CCRMUs that could be subject to the CCR requirements.

Q. IS THERE LEGAL UNCERTAINTY AROUND THE LEGACY RULE?

A. Yes. The Legacy Rule was challenged by various parties and is in litigation before the U.S. Court of Appeals for the D.C. Circuit. Georgia Power's parent company, Southern Company, is a member of the Utility Solid Waste Activities Group, one of the industry groups that is a petitioner on the challenge. On January 31, 2025, petitioners filed opening briefs with the Court. Then, on February 13, 2025, the D.C. Circuit granted EPA's motion to hold the Legacy Rule litigation in abeyance for 120 days. Placing litigation in abeyance puts the litigation on pause, but it does not automatically stay the rule. Thus, at this time the Legacy Rule and its associated compliance dates are still in effect. Georgia Power will continue to monitor any new developments in the litigation and in the Legacy Rule and evaluate implications to the compliance strategy through the ECS process.

IV. CCR COMPLIANCE STRATEGY

Q. PLEASE DESCRIBE THE COMPANY'S CCR COMPLIANCE STRATEGY AS APPROVED IN THE 2022 IRP.

A. The Company's CCR strategy was approved in the 2019 IRP and again in the 2022 IRP and remains unchanged since the 2022 IRP. The Company CCR compliance strategy covers 12 sites that include 29 ash ponds, 12 CCR landfills, and construction of a new permitted landfill that will support ash pond closures in the future.

Q. WHAT IS THE COMPANY'S APPROACH TO IMPLEMENTING ITS ASH PONDS AND CCR LANDFILL CLOSURE STRATEGY?

A. Georgia Power engaged third-party solid waste permitting experts to develop robust site-specific closure plans, including engineering designs and construction schedules to comply with the CCR rules. These plans comprehensively consider relevant factors in determining the appropriate closure designs for each unit, including volume, site complexity, and duration of the required activities, and are certified by independent, qualified professional engineers. For closure-in-place units, closure plans are developed following a detailed, site-specific engineering analysis that incorporates proven engineering methods designed to enhance groundwater protection, improve closure effectiveness, and minimize future maintenance. The Company's site-specific ash pond closure designs are included in the state CCR permits and are evaluated in detail by Georgia EPD. Regardless of the closure method selected for each CCR Unit, the Company will comply with applicable federal and state regulations as currently or subsequently enacted.

Q. WHAT PROGRESS HAS THE COMPANY MADE WITH REGARD TO ITS CLOSURE STRATEGY?

A. Georgia Power has made significant progress in implementing its approved closure strategy. The Company's semi-annual CCR ARO progress reports, filed with the

Commission in Docket No. 43083, provide additional details on the program's implementation status; however, key highlights include:

- As closure construction has advanced, Georgia Power has continued to prioritize safety through comprehensive planning, hazard recognition, engineering controls, training, a behavior-based safety program, and rigorous follow-through with learning events when risks are identified. Site-specific health and safety plans are developed and routinely assessed to minimize risks. Advancement of pre-closure or closure construction activities at 29 ash ponds includes permitting, landfill development, ash beneficiation infrastructure to support closure, dewatering, ash excavation, ash consolidation and placement, installation of closure cover systems, installation of engineering controls, and site restoration.

- In 2024, over 2,000 groundwater samples were collected by independent, third-party groundwater professionals with results included in 62 routine groundwater reports submitted to the Georgia EPD and posted to the Company's public website.

- In 2024, independent wastewater treatment contractors treated approximately 1.7 billion gallons of water and independent sampling contractors conducted 557 sampling events for the effluent and receiving streams. To date, over 6.14 billion gallons of water have been treated and over 3,325 sampling events have been conducted for the effluent and receiving streams. Water quality monitoring data is reported to the Georgia EPD and summarized on the Company's public website monthly.

- Beneficial use operations of harvested ash continued at Plant Mitchell and was initiated at Plant Bowen with over 400,000 tons of ash beneficiated in 2024. Construction of the beneficial use facility at Plant Branch is underway.

Q. WHAT IS THE STATUS OF THE COMPANY'S PERMITTING PROCESS WITH THE GEORGIA EPD?

A. To date, Georgia EPD has issued a total of 17 final permits—two closure-in-place permits, eight closure-by-removal permits, and seven landfill permits. Review of the remaining 14 permit applications continues with active engagement between the Company and the state agency. In addition, Georgia EPD has begun the five-year permit review process and has issued various minor modifications as projects have progressed for previously issued permits.

While Georgia EPD continues to maintain its EPA-approved state CCR permitting program, EPA involvement in Georgia CCR permits has increased in the last few years. In early 2024, EPA sent Georgia EPD a letter questioning the issuance of the final permit for Hammond AP-3, three months after the permit was finalized and more than two years after the draft permit was issued, and requested continued communication on all permit issuances. In April 2024, Georgia EPD responded to EPA stating that the permit was issued in accordance with the approved Georgia CCR Rule and meets the closure performance standards. Coordination between Georgia EPD and EPA on the Georgia CCR program is expected to continue for subsequent permitting actions.

With additional developments expected in 2025 related to Legacy Rule compliance, ongoing litigation, and other EPA actions, Georgia Power remains committed to working with Georgia EPD on the issuance of its remaining CCR permits, as required by the Georgia CCR Rule.

Q. WHERE CAN INTERESTED PARTIES LEARN MORE ABOUT GEORGIA POWER'S CCR PROGRAM?

A. Georgia Power maintains a comprehensive website detailing environmental compliance and project progress. The website includes details on the CCR permit application process with the Georgia EPD, providing extensive information on the

Company's closure plans and opportunities for engagement from stakeholders. The Company also publishes the results of water treatment, which are performed by independent third-party professionals and analyzed by accredited independent third-party laboratories, and publishes its semi-annual groundwater monitoring reports as submitted to EPD.

Additionally, in accordance with the 2019 IRP Order, Georgia Power continues to provide semi-annual progress reports to this Commission as well as annual updates with the annual ECS filing.

Q. HAS GEORGIA POWER REVISED THE COST ESTIMATES FOR ITS CCR COMPLIANCE STRATEGY?

A. Yes. Georgia Power consistently monitors and evaluates project assumptions, including, but not limited to, timing and schedule assumptions for permits and construction, project scope, post-closure activities, and estimated future escalation. The Company provides these updates in its CCR ARO semi-annual progress reports. As reflected in the CCR ARO tables in the Selected Supporting Information section of Technical Appendix Volume 2, Georgia Power's current forecast applicable to retail customers over the next 60 years is approximately $8.0 billion, which includes $1.7 billion in project to date actual costs incurred through December 31, 2024.

V. <u>BENEFICIAL USE</u>

Q. WHAT IS BENEFICIAL USE?

A. Beneficial use refers to the recycling or reuse of CCR into a marketable or useful product. Typically, CCR is reused as a key component in concrete products and wallboard. Ash adds strength and longevity when included in concrete specifications, while gypsum can replace mined gypsum for wallboard. Ongoing research continually seeks new beneficial uses for CCR, such as Georgia Power's involvement in research associated with extracting rare earth elements, which have applications in electronics manufacturing.

Q. WHAT ARE THE POTENTIAL BENEFITS OF INCORPORATING BENEFICIAL USE INTO CERTAIN ASH POND CLOSURES?

A. Benefits associated with the beneficial use of CCR can include increased ash sales, reduced closure costs, and reduced long-term liability. Reduced costs could take the form of reduced ash volumes moved during closure, a reduced closure footprint, reduced landfill space needed to support closure, and/or reduced post-closure care.

Q. WHAT IS GEORGIA POWER'S APPROACH TO BENEFICIAL USE OF HARVESTED CCR IN ASH POND CLOSURE?

A. Georgia Power uses a market-driven approach to optimize the potential of beneficial use in ash pond closure for the benefit of customers. This approach ensures that the benefits of harvested ash reuse is balanced with the infrastructure investment required and that the ash market remains able to absorb the amount of harvested ash produced from the Company's sites.

Q. PLEASE DESCRIBE GEORGIA POWER'S EFFORTS TOWARDS THE BENEFICIAL USE OF CCR.

A. The Company's CCR beneficial use efforts, as detailed in the ECS, center around three primary areas: (1) marketing of CCR from ongoing plant operations; (2) continued development of new research and technology for beneficial use of CCR; and (3) implementation of market-driven beneficial use projects at the Company's ash ponds and landfills.

<u>CCR Marketing</u>: Georgia Power has marketed, over a five-year average, over 85% of its CCR generated from plant operations for beneficial use. This results in a reduction in CCR, which helps minimize or offset costs related to CCR storage, landfill construction, and associated O&M.

Research & Technology: Georgia Power, in partnership with the Electric Power Research Institute ("EPRI") and other utilities, continues its efforts at the Ash Beneficial Use Center ("ABUC") located at Plant Bowen. The ABUC strives to develop additional beneficial uses and better technologies to process harvested ash for beneficial use. The Company continues to develop and explore research and beneficial use development opportunities as approved and further detailed in the 2019 and 2022 IRPs. Southern Company is also collaborating with Winner Water Services and Eco Material Technologies on a DOE-funded project to conduct a Front-End Engineering Design ("FEED") study for a commercial-scale rare earth elements extraction plant using coal ash as feedstock. The paper study will be based on Georgia Power's Plant Branch in Milledgeville, Georgia, as host site.

Implementation of Beneficial Use Projects: As part of site-specific ash pond closures, the Company currently has several beneficial use projects underway. At Plant Mitchell, Georgia Power anticipates that up to approximately two million tons of coal ash will be removed from Plant Mitchell's ash ponds to help create Portland cement. By the end of 2024, nearly half of this material has been removed and shipped off-site for beneficial use. This will further reduce the amount of ash required to be removed and relocated to an off-site landfill and ultimately result in the production of a valuable product.

At Plant Bowen, infrastructure construction for the new beneficial use facility is complete and commercial operations began in first quarter of 2024. Transportation of harvested ash from Plant Bowen's beneficial use facility for use in the ready-mix concrete market began in the first quarter 2024, with approximately nine million tons of ash anticipated to be harvested, processed, and removed from the site over the duration of the contract period.

Georgia Power also finalized an agreement for the beneficial use project at Plant Branch in May 2023, and investments are currently underway to build a processing facility with plans to excavate up to eight million tons of coal ash from on-site ash ponds for use in concrete. This will reduce the volume of ash to be landfilled on site.

VI. CLIMATE & CARBON PRESSURES

Q. WHAT ARE THE CARBON PRESSURES ON GEORGIA POWER'S GENERATING FLEET FROM CLIMATE AND ENVIRONMENTAL POLICY?

A. In addition to the constraints imposed by new regulatory requirements such as the 111 GHG Rules, potential future climate regulation or legislation and evolving customer needs also present potential challenges and opportunities that are important to consider in the Company's overall planning process. In general, potential carbon cost or other climate-related pressures on generating units are highest for coal-fired generating units but also affect other fossil fuel-fired power plants.

Q. HOW IS THE COMPANY INCORPORATING THIS INCREASED CARBON PRESSURE INTO ITS PLANNING PROCESSES?

A. As described in the Direct Testimony of Witnesses Grubb, Hubbert, Looney, Robinson, and Valle, the Company's robust scenario planning process provides the best way to capture potential financial impacts and allow for long-term planning to mitigate risks to customers. Georgia Power included six scenarios in the IRP to reflect and evaluate carbon pressure: two scenarios are based on the 111 GHG Rules, three scenarios reflect varying levels of future carbon regulation and price pressure, and one scenario reflects the future adoption of an overall carbon emissions limit for the generating fleet. Considering the level of uncertainty in future climate policy, continued use of a range of carbon scenarios and costs in long-term planning best positions the Company to monitor and evaluate the outcome of executive, legislative, and regulatory actions and incorporate any new information into the planning processes as appropriate.

The Company continues to focus on the importance of planning strategically within the state regulatory framework to address the risks presented by carbon policy by ensuring a flexible generation fleet. Georgia Power recognizes that the feasibility of continued progress toward a low-carbon future is highly dependent on the continued use of natural gas and continued technology advancements. The Company's long-term planning approach considers these factors through a diverse resource portfolio leveraging low- and zero-carbon technologies, continued technological advancements, and constructive engagement with stakeholders to address the evolving energy needs and preferences of customers.

VII. CONCLUSION

Q. WHAT IS GEORGIA POWER REQUESTING OF THE COMMISSION IN THE 2025 IRP AS IT RELATES TO THE ECS AND ENVIRONMENTAL COMPLIANCE?

A. The Company seeks approval of the 2025 ECS. This includes the capital, O&M, and CCR ARO costs and associated measures taken to comply with federal and state environmental mandates, as set out in the ECS in Technical Appendix Volume 1 and the ECCR and CCR ARO tables in the Selected Supporting Information section of Technical Appendix Volume 2, as well as the authority to pursue the natural gas co-firing compliance pathway as the 111 GHG Rule strategy for Plant Bowen and Plant Scherer.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

MR. MARZO: And with your permission, I'd ask Ms. McNelly to also be allowed to summarize the panel's testimony.

CHAIRMAN SHAW: Yes, sir. Go ahead.

MS. MCNELLY: Good afternoon, Commissioners.

We appreciate the opportunity to appear before you today. The purpose of our testimony is to support Georgia Power's Environmental Compliance Strategy, or "ECS," which is a comprehensive strategy designed to provide cost-effective plans for the Company to meet its environmental compliance obligations while providing customers with clean, safe, reliable, and affordable energy.

Building on the success of the company's previous ECS filings, the 2025 ECS seeks to provide flexibility and optimize compliance in an increasingly dynamic and uncertain regulatory environment. The ECS considers existing and potential legislative and regulatory requirements and identifies plant-specific compliance options. Georgia Power evaluates these options considering the available technology, cost, schedule, plant operations, and the environment. This iterative approach is designed to provide Georgia Power with the necessary flexibility to develop and refine its compliance plans in the best interests of customers as additional information becomes available.

Georgia Power's ECS provides an update on key regulatory and strategy changes since the 2022 IRP, including the company's compliance strategy related to the four rules finalized by EPA in 2024 that impose new requirements on utilities. These rules include: Greenhouse Gas emissions limitations pursuant to the Clean Air Act, Section 111; revised mercury and air toxics standards; revised and supplemental Effluent Limitations Guidelines, or "ELG"; and coal combustion residuals, or "CCR," rule amendments through the legacy CCR Surface Impoundments rule.

As discussed in the ECS, the company is pursuing the natural gas co-firing compliance pathway as the 111 Greenhouse Gas Rule strategy for Plant Bowen and Plant Scherer. The ECS also details the ELG compliance options the company has selected under the 2020 and 2024 ELG rules. For Plant Scherer, the company is continuing its efforts under the voluntary incentives program compliance option; and for Plant Bowen, the company is evaluating feasible options for additional controls. The 111 greenhouse gas and ELG compliance strategy benefits customers by providing a balanced plan to comply with existing requirements while maintaining flexibility to select the most appropriate unit-specific compliance options. This is the best plan to address the continuing uncertainty around the ultimate outcome of these rules.

The company's CCR compliance strategy, approved in the 2022 IRP, including management and closure of 29 ash ponds and 13 landfills, continues to be effectively implemented under the oversight of the Georgia Environmental Protection Division. The company has made significant progress in implementing its approved closure strategy, including opportunities to maximize the beneficial use of stored coal ash at its active and retired plants across the state.

With the Commission's oversight, the company is well positioned to continue to build on successes for the benefit of customers with its 2025 ECS through cost-effective strategy optimization, reliable operations, and environmental compliance.

Thank you, Commissioners.

MR. MARZO: Thank you, Panel.

Mr. Chair, the witnesses are available for questions from the Commissioners as well as cross-examination.

CHAIRMAN SHAW: Commissioners, any questions for this panel?

(No response.)

CHAIRMAN SHAW: All right. We will begin with cross, starting with Georgia Public Service Commission.

MR. PAWLUK: Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. PAWLUK:

Q. Good morning, Ms. McNelly, Mr. Mitchell. My name is Justin Pawluk, and I'm a lawyer here at the Public Service Commission representing the Public Interest Advocacy staff for this IRP hearing.

MR. PAWLUK: Before we get started, Mr. Chairman, may I have permission to distribute exhibits to the panel and the bench?

CHAIRMAN SHAW: Sure, go ahead.

MR. PAWLUK: We are going to be marking this as STF-PIA-7.

(The documents referred to were marked for identification as GPSC Exhibit 7.)

BY MR. PAWLUK:

Q. Before I start asking some questions about the ECS, I just have a couple questions about costs and how they're going to be recovered by the company for some of these environmental compliance measures. In general, environmental compliance costs are paid for by the company's customers as part of their electric bills; isn't that correct?

A. (Witness McNelly) That's correct.

Q. And that's sometimes referred to as the Environmental Compliance Cost Recovery, or ECCR; is that right?

A. (Witness McNelly) Yes.

Q. Now, I'd like to ask you a couple of questions about that exhibit that we just passed out, which is staff's data requests STF-LA-19 (sic). The response to STF-LA-1-19 indicates that the ECCR revenue requirement is not subject to true-up or reconciliation of actual costs; is that correct?

A. (Witness McNelly) That's correct.

Q. Does the company maintain tracking of whether it is over-recovering its ECCR costs?

A. (Witness McNelly) Not to my knowledge, no.

Q. In 2023 or 2024, did the company over-recover its CCR costs, do you know?

A. (Witness McNelly) As a normal -- you know, the company doesn't maintain a balance on the over- or under-recovery of the ECCR costs.

Q. Thank you.

And I think we -- it's fair to say that there's quite a bit of uncertainty about environmental costs affecting the company going forward, and all these rule uncertainties that you've discussed; is that correct?

A. (Witness McNelly) Yes, there is uncertainty.

Q. Do you think it would make sense, given all those uncertainties, that there would be a true-up procedure at some point so that the actual costs of compliance match up with what's being recovered from the rates?

MR. MARZO: Mr. Chairman, I'm trying not to object, but I think we're getting into rate case issues in terms of how an ECCR is collected, whether there's a true-up or not a true-up. It's a rate case issue. That mechanism is recovered through rate cases.

CHAIRMAN SHAW: So are you also saying that your panels in the rate case would be more prepared to answer this question than this panel?

MR. MARZO: This panel can talk about the costs that are in the tables that support the ECCR that would be asked to be covered in the rate case. But in terms of the mechanisms that would be utilized for that recovery, whether or not there's a true-up, that's a rate case issue.

So if there's questions about the cost, they can answer those.

CHAIRMAN SHAW: Yes, let's try to stick to the resource planning document before us.

MR. PAWLUK: That's fine, Mr. Chairman. I appreciate it. Thank you.

COMMISSIONER PRIDEMORE: Can I ask a question about costs though? So the company doesn't track costs related to -- I assume they track costs related to the expenditure of the coal ash clean-up; right?

MS. MCNELLY: That's right.

COMMISSIONER PRIDEMORE: Yeah. And is it treated the same or differently than other environmental regulatory costs?

MS. MCNELLY: I'm going to let Mr. --

COMMISSIONER PRIDEMORE: Are they tracked individually, I guess?

MS. MCNELLY: I'm going to let my colleague, Mr. Mitchell, answer for coal combustion residuals, or CCR tracking.

MR. MITCHELL: Yes, the coal combustion residual costs are tracked, and we update those in our annual compliance filing. We also update those costs on a semiannual basis with our semiannual CCR reports. So those are routinely updated to this Commission.

MS. MCNELLY: And the ECCR are separate from that coal ash closure.

COMMISSIONER PRIDEMORE: So CCR costs -- so CCR Arrow is handled separately from the ECCR tariff?

MR. MITCHELL: It's part of the ECCR tariff, but it is -- I don't know about the accounting -- proper accounting language, but it is counted separately.

COMMISSIONER PRIDEMORE: That's okay. Neither one of us are accountants. It's all right.

MR. MITCHELL: It's treated separately, in simple terms.

COMMISSIONER PRIDEMORE: Okay. Okay. Are other environmental-related costs captured uniquely, like clean-up at a hydroplant?

MS. MCNELLY: All the normal environmental compliance costs are captured in the ECCR tables, excluding what Mr. Mitchell mentioned for the CCR

Arrow. So they're all tracked and part of the normal cost of doing business for environmental compliance.

COMMISSIONER PRIDEMORE: Okay.

MS. MCNELLY: In both capital and O&M.

COMMISSIONER PRIDEMORE: Okay. Thank you.

BY MR. PAWLUK:

Q. Looking at the panel's testimony, beginning on page 10, line 20, the company testified -- or I guess the panel testified, "The final outcomes of ongoing litigation, potential executive actions, and potential subsequent rulemaking may take years to resolve, and this uncertainty requires Georgia Power to work towards compliance with final regulations as implemented by EPD through its permits and state plan, while staying flexible for various outcomes, including the suspension of some or all rule requirements."

Do you see that?

A. (Witness McNelly) Yes.

Q. So in the company's recommended 111-MG0 planning scenario, the company is planning based on the assumption that the 2024 111 GHG rules will remain in effect as they stand now; is that correct?

A. (Witness McNelly) That's correct.

Q. Just generally, how would the company's

compliance plans change if those rules were to be suspended or repealed?

A. (Witness McNelly) Well, as I believe you heard in panel one, Commissioners, there's a lot of scenarios that are run as part of the modeling that panel one is responsible for. But in general, the expectation is, if 111 stays around, for lack of a better way to say it, then that's the base case of how that's modeled.

And then there are other modeling scenarios that were performed by panel one's experts to include other versions of carbon pressure that are not exactly the same as 111. So there are compliance considerations for that rule, and the expectation is we will be compliant with the rule because it is currently on the books.

Q. Okay. But in terms of engineering changes or resource acquisition or retirement, just sort of generally, what would those changes be?

A. (Witness McNelly) I can't speculate because I don't know how the changes of the rule -- what effects the changes of the rule will impart, but this regulatory process and the filing of the environmental compliance strategy allows us to be flexible and adaptable to change to the changing circumstances, or adapt to the changing circumstances.

And so as we have done previously, we will

continue to adjust our planning based on what's -- the circumstances change and remain in compliance, while keeping customers at the center of that calculus.

A. (Witness Mitchell) And I might add, just as a reminder, the environmental compliance strategy that Ms. McNelly spoke of, it is filed annually with this Commission.

Q. Now, looking at the testimony on page 12, line 12, the panel testified, "Two of the three pathways for coal units outlined in EPAs 111 GHG rules: Retire by January 1, 2032, or install and operate CCS, are not only costly but also impractical."

Do you see that?

A. (Witness McNelly) Yes.

Q. Why would it be impractical, in your opinion, to retire the coal units or install and operate CCS?

A. (Witness McNelly) Well, let me start with the CCS. The CCS current technology is not technically ready or deployable at this scale for these units, and is not cost effective for customers at this point.

Not only is the technology for CCS still under development and -- we'll just say development, but also the infrastructure needed for CCS is pretty intense. It includes not only pipeline, infrastructure but also potentially geologic storage. And so the CCS choice, at this time, is not the right choice for customers.

As I believe you also heard from panel one, the large-load growth in the state means that we need capacity, and retiring the good resources that we have in these units is not the right choice for customers at this time. It's not the most cost-effective choice for customers at this time. So we made those decisions and that compliance pathway recommendation based on those limitations.

Q. And so by "impractical," you really mean "not cost-effective"; is that correct?

A. (Witness McNelly) That's -- no, I don't agree with that because it's not technically feasible or deployable at this point for CCS. There is almost an economic and cost effective -- or cost consideration as part of that balance as well.

Q. So the company's recommended strategy, then, I gather, is to proceed with modifying the Bowen and Scherer coal units by the January 1, 2030, date to operate with 40 percent natural gas co-firing; is that correct?

A. (Witness McNelly) Yes. That's the recommended pathway.

Q. Now, what does "40 percent co-firing natural gas" mean? Does that mean that -- does the 40 percent refer to the mass of the fuel that's being expended to heat the boilers, or is that the amount of heat being generated from burning each type of fuel, or the energy that's being generated? Help me out here.

A. (Witness McNelly) I think the simple way to understand or explain that is to talk about -- the total production of that unit is 40 percent of that production is fueled by natural gas.

Q. And that's in terms of megawatts hours?

A. (Witness McNelly) I think you can think about it that way, yes.

Q. Looking at page 14 of the testimony, starting at line 10, you testified, "As part of Georgia Power's ECS, the 111 GHG rules strategy for Plant Bowen and Plant Scherer is to pursue the natural gas co-firing compliance pathway, starting with engaging engineering firms to perform boiler studies to determine potential designs for adding natural gas co-firing capability."

Do you see that?

A. (Witness McNelly) Yes.

Q. Now, what engineering firms do you anticipate engaging with to perform those boiler studies?

A. (Witness McNelly) The actual contractual part of that is trade secret, and it is, Commissioners, like traditional preconceptual -- or conceptual engineering work, to do studies to understand the scope of what that modification might look like, and it is a typical engineering study with an engineering firm.

Q. Are there more than one engineering firms out there who have experience doing this type of work?

A. (Witness McNelly) Yes.

Q. And how many coal plants in the United States are you aware of that have been successfully retrofitted with natural gas burners for co-firing?

A. (Witness McNelly) I don't know the number for the U.S. I do know that we have success within our fleet, Commissioners, of that modification.

Q. Which units are those?

A. (Witness McNelly) There are a couplE in our fleet, including the units at Plant Yates 6 and 7, as well as some others across the fleet.

Q. And has the company been successful with that?

A. (Witness McNelly) Yes.

Q. When was that done, do you know?

A. (Witness McNelly) I don't have those dates, but I could probably look it up for you, but in the teens.

Q. Is there a ballpark? Years?

A. (Witness McNelly) In the teens.

Q. Teens. Thank you.

Looking at page 15 of your testimony, having to do with the company's MATS compliance strategy, beginning environmental beginning on line 14. You testified, "Compliance will require the addition of new particulate matter continuous emission monitoring for each of the Plant Bowen units 1 through 4 and Plant Scherer units 1 through 3."

Could you elaborate a little bit more on what you mean by "continuous emissions monitoring"?

A. (Witness McNelly) Yes. So, Commissioners, MATS rule is not new. We've been complying with the MATS rules for several years now. And MATS rules currently, there is a provision where you can test your emissions on a periodic basis.

The MATS current -- new MATS rule that was issued in 2024 requires continuous emissions monitoring, and that -- you can think about that as analyzers that are continually running, to monitor continuously. And so the addition of those analyzers or monitors is what the requirement of that rule requires, and that's part of our plan moving forward, to comply with the 2024 MATS rule.

Q. But those monitors haven't been installed yet; right?

A. (Witness McNelly) That's right.

Q. Okay. And, I mean, is that a new technology or is it --

A. (Witness McNelly) No, it's not a new technology. The technology is advancing, so it's one of those things that has gotten better over time. And we're still in the process of evaluating which monitors will be needed for our units. Those are required in 2027.

Q. And, you know, I'm not asking about the cost to ratepayers, but what would be the cost to the company of installing that technology?

A. (Witness McNelly) The details of those analyzer additions are trade secret, but they're minimal. They are monitoring costs similar to traditional O&M or small capital.

Q. Are there any other engineering challenges involved with installing that monitoring system?

A. (Witness McNelly) Not really.

And, Commissioners, I'd like to take this opportunity to talk about the fact that we have been in compliance with MATS for a long time. And so this new MAT's rule actually doesn't require us to add any engineering work to change how we operate our units. It is more of a monitoring change and how we monitor.

Q. Looking on page 16 of the testimony, beginning on line 22, you testified, "The 2024 ELG rule adds additional requirements to the ELG rules described above and sets forth more stringent compliance pathways for the company's scrubber wastewater and CRL."

What is "scrubber wastewater"?

A. (Witness McNelly) Can I ask you again that reference? I didn't find it fast enough.

Q. Oh, I'm sorry. I'm looking at page 16, line 22.

A. (Witness McNelly) Okay.

Q. So what is "scrubber wastewater"?

A. (Witness McNelly) So, Commissioners, scrubbers are pollution control devices that were installed in the last 20 years or so, that reduce SO2 and other air constituents. And so scrubbers are wet systems on our fleet, and those systems include treatment that treats for SO2 by using limestone. And the byproduct of that scrubbing is gypsum, which is sold into the market for wallboard and wastewater. So that wastewater is treated, and that scrubber wastewater is one of the byproducts or the discharges from that scrubber SO2 treatment device.

Q. Okay. What is CRL? I appreciate the explanation.

A. (Witness McNelly) Sure. CRL is combustion residual leachate, and I'll let my colleague Mr. Mitchell talk more about that.

A. (Witness Mitchell) So, yes, combustion residual leachate is collected in -- landfills are designed to collect leachate, and so that is the leachate from landfills. And so our plants have landfills for which -- whatever ash is not sold into the market goes into the landfills, and then the leachate from those landfills is the CRL portion of this ELG.

Q. Okay. Thank you. I appreciate that as well.

Continuing with that quote that I started on page 16, it goes on to say, "Most significantly, the 2024 ELG rule established a ZLD requirement for scrubber wastewater and CRL from the company's coal-fired generating units."

What is "ZLD"? Does that refer to zero liquid discharge?

A. (Witness McNelly) Yes, that's right.

Q. So how does the company plan to achieve zero liquid discharge for its coal plants' scrubber wastewater and CRL by the end of 2029?

A. (Witness McNelly) The ELG rule bases its limit on a suite of technologies that can be used to reduce the discharge from scrubber wastewater treatment to zero. And that includes a combination of membrane treatment, so like a reverse osmosis -- it's kind of like a contact lens, that kind of treatment -- combined with evaporation and crystallization. And so that is the company's current plan, is a configuration of those options to treat for -- to make it ZLD of that scrubber wastewater stream.

Q. Okay. And, again, I mean, how much do you think that will cost for Bowen and Scherer?

A. (Witness McNelly) While the specifics are trade secret, the cost for that ELG treatment is significant, on the order of hundreds of millions of dollars.

Q. I'm sorry. Did you say hundreds of millions of dollars?

A. (Witness McNelly) That's right.

Q. Now, looking ahead to page 17 of your testimony, line 14, the panel testified, "In light of the continuing" -- I'll let you get to it. So that was page 17, line 14.

A. (Witness McNelly) Got it.

Q. You testified, "In light of the continuing increase to the company's projected load forecast, and the magnitude of the capacity needs in 2020 and beyond, as discussed in the direct testimony of Witnesses Grubb, Hubbert, Looney, Robinson, and Valle, the company is making a formal recommendation in this IRP to continue operations for Plant Bowen units 1 through 2, as well as extending the operation of Plant Scherer unit 3 and Plant

Gaston units 1 through 4 beyond the 2028 retirement dates approved in the 2022 IRP."

Do y'all see that?

A. (Witness McNelly) Yes.

Q. Isn't it true that the only reason for keeping these coal units going, in spite of the costs and some of the engineering challenges that you've described, is because of the projected load increases from the large-load customers, including the data centers?

A. (Witness McNelly) Yes. Commissioners, as I believe you heard from Panel 1, and we've talked about is the fact that this extraordinary load growth in the state means that out -- we need capacity, and we need to do that in the most cost-effective way for our customers.

And so my understanding of the reason for the extenuation of those units -- or the extension of those operations of those units is to meet that capacity load for all the large-load, as well as the needs of our customers.

Q. I mean, it doesn't make your job any easier from an environmental compliance standpoint, does it?

A. (Witness McNelly) Well, not necessarily, but that is the job. The job is to ensure that our environmental compliance technology is adequate and that it's doing its job, and it's run well, and it's run efficiently, so that those units can continue to produce our product for the best interests of our customers.

Q. Moving on to parts four and five of your testimony related to coal combustion residuals or CCR, what does CCR include, just generally?

A. (Witness Mitchell) Coal combustion residuals include ash, flash, bottom ash, and gypsum, and Ms. McNelly described gypsum a while ago and how it's collected.

Q. And you talked a little bit earlier in your summary about beneficial use. Are there beneficial uses for coal combustion residuals?

A. (Witness Mitchell) Yes, there are. So flash is a heavily sought-out commodity that typically goes to the concrete industry, and so flash is used into ready-mix concrete. And then gypsum is, as Ms. McNelly spoke to, is heavily used in the wallboard industry.

Georgia Power has a long history of recycling our operational ash. Over 85 percent of our production ash from our active facilities has gone to the market for years, and then we are also including -- we're the market conveyer, so it's based on a market-driven approach, beneficiating ash from our ash pond closures and trying to move that material to the market, and those benefits offset costs to our ash pond closures.

Q. Now, looking at page 25, lines 24 to 27.

A. (Witness Mitchell) I'm sorry. Page 25?

Q. Yes. I believe you indicated in 2024, the company harvested ash at Plant Mitchell and initiated harvesting at Plant Bowen, with over 400,000 tons for beneficial use; is that correct?

A. (Witness Mitchell) That is correct.

Q. Approximately, how much revenue did the company receive from the 400,000 tons of ash resulting from that beneficial use?

A. (Witness Mitchell) So the exact numbers are trade secret, but those benefits do go back and they do offset the ash pond closure costs. At Plant Mitchell, that ash there is going to Portland cement manufacturers. And then the ash from Plant Bowen is primarily going to the ready-mixed concrete industry.

Q. To avail itself of the beneficial uses of CCR, the company must first incur some upfront costs; is that right?

A. (Witness Mitchell) That's correct.

Q. Through December 31 of 2024, approximately how much has the company incurred for upfront spending for ash processing infrastructure that could enable the beneficial use of CCR at each plant?

A. (Witness Mitchell) So at Mitchell, that we just talked about, there is none. The plan there is, material is dried, and it goes to the Portland cement manufacturers. So no processing infrastructure, you might say, other than normal management at a site.

And at Plant Bowen, there's a processing facility that dries the ash prior to it going to the market. And so that was a result -- the Bowen contract was a result of an RFP that we had completed in, I think, in 2023. And we provided a summary of that document to this Commission regarding the Bowen and the Branch projects that were awarded at that time.

Q. Now, looking at page 28 of your testimony, the panel testified that, "Georgia Power has marketed, over a five-year average, over 85 percent of its CCR generated from plant operations for beneficial use."

Do y'all see that?

A. (Witness Mitchell) Can you point to the line item again?

Q. I'm sorry. Page 28. I'm not sure what the line item is.

A. (Witness Mitchell) I got it. Yes, sir.

Q. It says, "Georgia Power has marketed, over a five-year average" -- and what do y'all mean here by "marketed"? Does that mean sold, disposed of, put up for sale? What --

A. (Witness Mitchell) That means it's sold to users of the ash.

Q. All right. Just means sold then?

A. (Witness Mitchell) That's right. And that is referring to the production ash, on that 85 percent that I spoke of a while ago, from the operational facilities.

Q. Thank you.

And I just have one more question. I do feel compelled, since Rule 515-3-4-.041(c) of the Commission's rules for IRPs does require that the ECS address low-level nuclear waste and high-level nuclear waste, and I didn't see too much in the ECS. I think it was the very last page of the plan. There was maybe one page about nuclear waste.

Have there been any changes or new developments, regulations, as to the disposal or storage of low- or high-level nuclear waste?

A. (Witness McNelly) No, sir.

Q. What are we doing with it? Are we just putting it on site at Hatch and Vogtle?

A. (Witness McNelly) We're complying with all the rules and regulations, and there are many in the nuclear space. And that's handled by our Southern Nuclear Company. And we're just continuing to do the same process as we have with that waste, for both of those sites.

MR. PAWLUK: All right. Thank you. Appreciate your time, Panel.

Mr. Chairman, I would like to move to enter Staff Exhibit STF-PIA-7 into the record.

CHAIRMAN SHAW: So marked.

MR. PAWLUK: Thank you.

(GPSC Exhibit 7 was admitted into evidence.)

All right. We'll keep going, starting with cross on the intervenors. We'll start with Advanced Power Alliance.

MR. CARVER: No questions, Mr. Chairman.

CHAIRMAN SHAW: Americans for Affordable Clean Energy.

MR. GALLOWAY: No questions, Mr. Chairman.

CHAIRMAN SHAW: Clean Energy Buyers Association.

MS. KVIEN: No questions.

CHAIRMAN SHAW: Capital Good Fund.

(No response.)

COMMISSIONER PRIDEMORE: I think she's gone.

CHAIRMAN SHAW: Fermata Energy.

(No response.)

CHAIRMAN SHAW: Georgia Association of Manufacturers.

MR. CHARLES JONES: No questions.

CHAIRMAN SHAW: Georgia Center for Energy Solutions.

(No response.)

CHAIRMAN SHAW: Georgia Coalition of Local Governments.

MR. SMART: No questions.

CHAIRMAN SHAW: Georgia Conservation Voters Education Fund.

MR. ESTRADA: No questions.

CHAIRMAN SHAW: Georgia Interfaith Power & Light and Southface.

COMMISSIONER PRIDEMORE: They were looking down, they were not looking up. They were staring at the carpet because they knew it.

All right, Jennifer. You're always welcome.

MS. WHITFIELD: Three questions, I promise.

And may Vanna White approach?

(The documents referred to were marked for identification as GIPL/Southface Exhibit 9.)

CROSS-EXAMINATION

BY MS. WHITFIELD:

Q. If you may, Mr. Sherrier is handing out what's been marked as GIPL/Southface Exhibit 9. And on this exhibit, I have questions about Figure 5, which is on page 4. And the page numbers were added by us, just for ease of reference, but this document was otherwise printed from the Southern Company website, and it's titled: The Southern Company Net Zero Q & A Supplement. And it's dated December 2023.

Figure 5 reflects EPRI's analysis, presented by Southern Company in this document, of potential cost-effective pathways by region to achieve net-zero greenhouse gas emissions. And my question is, if you agree with that summary -- if these reflect potential pathways that Southern Company believes would be appropriate for Southern Company to achieve net-zero greenhouse gas emissions in accordance with its goals?

A. (Witness McNelly) While I can't comment on the values of the pie charts for each of those, I believe that those are the general pathways that we expect to be available options for a path to net-zero.

Q. Thank you.

(The documents referred to were marked for identification as GIPL/Southface Exhibit 8.)

BY MS. WHITFIELD:

Q. And if Mr. Sherrier could approach with what has been marked as GIPL/Southface Exhibit 8. This document was printed yesterday from the Southern Company website. It is a Georgia Power economic development webpage on data centers entitled: Georgia, a Competitive

Advantage for Data Centers. And I'd like to direct your attention to the second page, where we were delighted to see that on the second page, in two different locations, Georgia Power is touting its commitment to net-zero carbon emissions by 2050.

Am I correct that Georgia Power has now adopted the Southern Company commitment to net-zero emissions by 2050 aspirate-specific commitment as well?

A. (Witness McNelly) Georgia Power continues to be in line with Southern Company's net-zero by 2050 plan, and nothing has changed in that commitment at the Southern Company level.

Q. So Georgia Power now has a commitment to net-zero emissions by 2050?

A. (Witness McNelly) As part of Southern Company, Georgia Power is aligned with the Southern Company net-zero by 2050 commitment.

Q. So no?

A. (Witness McNelly) There's been no change in the commitment to the overarching strategy for net-zero at the Southern Company level. We're, of course, part of that Southern Company, and so our -- nothing in this IRP deviates from that pathway.

MS. WHITFIELD: Thank you. No further questions.

CHAIRMAN SHAW: Georgia Solar Industries Association.

MR. COX: No questions.

CHAIRMAN SHAW: Georgia Solar?

He said he didn't have any.

Georgia Watch?

(No response.)

CHAIRMAN SHAW: Georgia WAND and Vote Solar.

MS. KVIEN: Good evening, Panel. Allison Kvien on behalf of Georgia WAND and Vote Solar.

CROSS-EXAMINATION

BY MS. KVIEN:

Q. In your written testimony and in the unit retirement study provided in Technical Appendix 1, you write that you found that co-firing is the most cost-effective option and that it poses lower risk than other options, including retirement, for compliance with GHG Rule 111; is that correct?

A. (Witness McNelly) Can you point me to where you're looking to make sure I'm looking at the right sentence, please?

Q. I left my page reference back there.

It is in your direct testimony. I can grab my page reference, if you need it.

A. (Witness Mitchell) I think we may have found it. Will you repeat the question?

Q. Sure.

In your written testimony and in -- also in the Technical Appendix 1 in the unit retirement study, you write that you found that co-firing is the most cost-effective option in that it poses lower risk than other options, including retirement.

A. (Witness Mitchell) If you could point us to the line. I don't know --

Q. I didn't write down my page number for it like I thought I did, but I think it's probably around page 12, if I had to guess.

A. (Witness McNelly) Okay. I'm not seeing that exact sentence, but I see some language that's similar.

Q. Do you remember that you wrote that it was -- that co-firing was the most cost-effective option of the three options and that it poses lower risk?

A. (Witness McNelly) Yes.

Q. Okay. That's all I need.

In asserting that co-firing is lower risk, did the company evaluate the potential for these investments to become stranded assets if legal, regulatory, or market pressures required an earlier exit from fossil fuels than 2039, when the company is currently proposing retirement?

A. (Witness McNelly) Commission, as we typically do, we evaluate these rules and changes in the circumstances on an annual or ongoing basis. And so while there is uncertainty around these rules, there are rules that are currently on the books that we're required and will comply with. And so developing the plan to comply with the 111 rule, despite the uncertainty in that space, is the appropriate thing for us to do.

Q. So you did not consider stranded asset risk, then, in making that assertion?

A. (Witness McNelly) The way that our plan works, the flexibility of our plan, and the ability for us to adapt that plan, reduces any risk of that. Makes sure it is -- as always, any investment could change, but the fact that we can be flexible and adaptable and do that every year allows us to minimize that risk to customers while still adhering to our commitment to be in compliance with the rules that are on the books.

Q. And in asserting that co-firing is lower risk, the lower risk option of the three, did the company consider fuel-volatility risk from further investment in natural gas?

A. (Witness McNelly) Again, I think as Panel 1 stated, that is a part of the evaluation that Panel 1 does when they run these evaluations. We supply the inputs to those discussions and those models on the constraints around the environmental rules that are changing, and my understanding is those analyses take that into account.

Q. And finally, did you consider -- in asserting that co-firing is the lower risk option of the three, did the company consider health and environmental noncompliance risks to communities surrounding those fossil fuel plant facilities?

A. (Witness McNelly) Commissioners, as you know, we work and play and live in these communities. We live in the state, and our employees. It's important to us that we maintain, not only compliance, but also that we're good stewards of the environment, and we maintain that commitment.

Q. Right. I'm just trying to understand the factors that you considered when you write that this -- that the co-firing option was the lower risk option of the three.

A. (Witness McNelly) The factors that are considered are economic, as we do -- benefiting our customers, we balance quite a few constraints and benefits. That includes providing our product to our customers to provide clean, safe, reliable, and affordable, and we balance those risks and those benefits of producing that product for our customers.

Q. Given that the company's proposed co-firing retrofit would only operate for nine years between 2030 to 2039, has the company calculated the break-even point for recovering the upfront capital costs for that investment?

A. (Witness McNelly) I'm not sure of the details of that. I think that was -- our Panel 1 experts do that as part of their analysis, but I'm not privy to the -- I don't have those details in front of me.

Q. Did you conduct a full life-cycle-emission analysis, including potential upstream methane leakage for the natural gas that would be used in the co-firing scenario?

A. (Witness McNelly) I'm not sure if that analysis is run on a case by -- or a unit-by-unit basis for considering this, but we are, and have been, very transparent with our emissions information, both on our website and with this Commission, and will continue that commitment to transparency to make sure that everyone knows the choices are in the best interest of our customers.

MS. KVIEN: All right. Thank you. No further questions.

CHAIRMAN SHAW: Thank you.

All right. Next is MARTA.

MS. EATON: No questions.

CHAIRMAN SHAW: Micro- -- yes?
MS. WHITFIELD: If I may, I forgot to move in my exhibits GIPL and Southface Exhibits 8 and 9.
CHAIRMAN SHAW: That's the last two, 8 and 9?
MS. WHITFIELD: Yes.
CHAIRMAN SHAW: So marked.
(GIPL Exhibits 8 and 9 were admitted into evidence.)
mr. hewitson: GIPL, weren't you 9 and 10?
MS. WHITFIELD: 8 and 9.
CHAIRMAN SHAW: 8 and 9.
MS. WHITFIELD: Thank you.
CHAIRMAN SHAW: Microsoft?
MR. DOWDY: No questions, Mr. Chairman.
CHAIRMAN SHAW: Resource Supply Management.
(No response.)
CHAIRMAN SHAW: Resource Supply Management.
(No response.)
CHAIRMAN SHAW: Sierra Club. Southern Alliance for Clean Energy and the Natural Resource Defense Counsel.
MS. ARIZA: Thank you.
CHAIRMAN SHAW: Just for planning purposes only, do you have an idea of time?
MS. ARIZA: Not much at all.

CHAIRMAN SHAW: Well, let's go then.

MS. ARIZA: Less than three pages, I think.

CROSS-EXAMINATION

BY MS. ARIZA:

Q. Good evening, Panel. My name is Isabella Ariza and I represent NRDC, SACE, and Sierra Club in these proceedings.

Staff asked you a bunch of my questions, so I'll be brief. Would you agree --

A. (Witness McNelly) Sorry. Ma'am, we can barely hear you. This air conditioner is super loud.

Q. I'll try to speak closer.

You've talked about modeling 111 rules, would you agree that you model them because it's prudent to model existing on-the-books, applicable laws?

A. (Witness McNelly) Yes.

Q. Isn't it true that it would be imprudent to fail to assess environmental compliance obligations currently on the books?

A. (Witness McNelly) Yes.

Q. Would you also agree that modeling that 111 rule can serve as a proxy for other future environmental regulations that are likely to occur over the next 30 years? Over the plan --

A. (Witness McNelly) Did you say the next 30 years?

Q. Yeah. Over the next -- yeah, or over the planning period. Is modeling 111 a good proxy?

A. (Witness McNelly) Yeah. I think modeling any rules that are on the books is appropriate for our customers for the future.

Q. But, in particular, modeling 111 could be a good guide to what is going to happen in the carbon regulation over the next 30 years, for example?

A. (Witness McNelly) It's certainly one of the ways that it could be regulated in the future. I think Panel 1 mentioned, also, that there are other scenarios that were modeled to take into account other possible carbon pressures, and so while 111 is a good model, there are others that were modeled as well to have a robust planning picture.

Q. Thank you.

On page 8 of your testimony, lines 12 through 17, you say that since 1990, Georgia Power has reduced NOx and SO2 by more than 95 and 99 percent, respectfully; is that correct?

A. (Witness McNelly) That's correct.

Q. Do you agree that those reductions have been beneficial to ratepayers?

A. (Witness McNelly) Yes.

Q. Wouldn't you agree that further reductions in NOx and SO2 would also be beneficial?

A. (Witness McNelly) Yes, but marginally so because they're so close to 100 at this point, you know. Those are very large reductions. And those environmental controls that were put on to make those reductions, in the best interest of customers, are doing a great job, they're well-maintained and they're continuing to serve their purpose.

Q. But since you're asking to keep your coal fleet online for longer, your emissions -- your NOx and SO2 emissions will no longer decrease, they will increase; correct?

A. (Witness McNelly) No. They will continue to maintain that level of performance because those technologies, that environmental equipment, will continue to perform at that removal rate. And it continues to serve our customers well; correct?

Q. Well, at least compared to retiring those units, the emissions will increase because you're keeping them online for longer now?

A. (Witness McNelly) Can you restate that, just to make sure I understand what you're asking?

Q. The SO2 and NOx emissions will no longer continue decreasing because you're no longer retiring coal units; correct?

A. (Witness McNelly) Not necessarily. So it depends on how long -- you know, they're continuing to remove at that level, and so depending on how long they run, they will continue to remove at that level. And so there will be incremental changes, but it generally will be removing those levels for those units at that rate.

Q. But emissions won't decrease; correct?

A. (Witness McNelly) I think you're saying they won't decrease anymore.

Q. Exactly.

A. (Witness McNelly) And I'm saying that they're going to continue that level of performance because they're well-operated and well-maintained and they're going to continue to reach almost 100 percent removal of those constituents from those units.

Q. Okay. Did you create a -- so please turn to Figure 1 of your environmental compliance strategy. It's on page 8. Did you create a figure similar to this one which shows NOx and SO2 and CO2 emission trends but for future years?

A. (Witness McNelly) No.

Q. You don't know -- so you don't know how much your emissions will fluctuate in the future?

A. (Witness McNelly) Not precisely, but through the decisions and the approvals of this Commission, we've removed our -- you know, more than 60 percent of CO_2 since 2007 levels, and we are committed to continuing a responsible fleet transition, and now expansion, as we go forward. So we don't have that out forward -- we didn't extrapolate that forward for this diagram, but we are continuing to provide a balanced portfolio, and that includes balancing the constraints, all the constraints, to meet the need of the customer.

Q. And what do you mean by "fleet transition"?

A. (Witness McNelly) So back to your figure, over time, the fleet has changed in transitioned, based on environmental rules, based on the needs of the customer, the demands of the market, and the technology that's available to do the thing to produce the energy that we're producing.

And so that fleet transition includes some retirements. It also includes adding new resources to maintain that diverse portfolio of all different kinds of resources: Fossil, hydro, nuclear, renewable, storage. And that balance is what we really believe is important to serve our customers best.

Q. Under fleet transition, you include coal retirements. Would you agree that that aspect of the transition has stopped with this IRP?

A. (Witness McNelly) We're on a continuum, so, no, I wouldn't agree with because over time things continue to change. The circumstances change, the needs of the customer changes, and the way that we continue to balance that portfolio -- we will continue to balance it in the best interest of customers. So I can't say that it has or hasn't stopped because it's always in flux. And that's why this process, being flexible and adaptable, has worked well in the past. We believe it will work well in the future.

Q. The panel yesterday said that maybe that transition -- I'm paraphrasing -- but that transition might have been put on pause. Would you agree with that?

A. (Witness McNelly) I think for this period, yes.

Q. And if it's a pause, do you know when it will resume?

A. (Witness McNelly) I don't. And, again, I'd remind Commissioners that the balanced portfolio, and all the things that we're also adding, make that balanced portfolio still the right choice. All those different resources allow for flexibility and affordability, which is important.

Q. Have you evaluated how continued reliance on coal, combined with data centers diesel generators that are showing up around the Atlanta area, could impact Atlanta's air quality?

A. (Witness McNelly) I can't speak to the diesel generators, but we are -- we remain committed to being in compliance with all rules and regulations at the federal and state level, and that includes all constituents. And so any of these choices or approvals that the Commission makes, take that as a presupposition that we will remain in compliance with all those regulations.

Q. So you haven't necessarily conducted that analysis of impacts to air quality; correct?

A. (Witness McNelly) Maybe could you restate the broader picture and not just the end part of that question?

Q. I think you said, "no," but I'll ask again: Have you conducted a study that analyzes the impacts to air quality due to keeping coal online for longer?

A. (Witness McNelly) We continue to maintain and be in compliance with all of our permits. Georgia EPD maintains that, as the protector of human health and the environment, and we will continue to maintain and comply with our permits to ensure that we are in -- in the right spot there.

Q. Thank you.

Have you had asked EPD to conduct an analysis

of that kind?

A. (Witness McNelly) No.

Q. Turning to CCR, on page 22, lines 16 through 20.

A. (Witness Mitchell) You're referencing testimony?

Q. Of your testimony, yes. Page 22, lines 16 through 20.

Here you reference the 2022 letter from EPA to EPD regarding your ash pond closures; correct?

A. (Witness Mitchell) Yes.

Q. In that communication, EPA indicated that its interpretation of the CCR rule is that CCRs cannot be left submerged in groundwater; correct?

A. (Witness Mitchell) Yes.

Q. Did that letter change any of your ash pond closure plans?

A. (Witness Mitchell) As we have spoken to this Commission before, all of our ash pond closure plans were site-specific plans designed by third parties with expertise in this area, and they were designed to comply with the rules. All of our closure plans include engineering measures. And EPA, on multiple occasions, themselves have said the engineering measures are appropriate to install, to comply with the performance

standards.

In Georgia, Georgia EPD has been approved by EPA to delegate -- they've been delegated by EPA to run the CCR program in Georgia. And so we have continued to provide EPD information that they request and to ensure we comply with EPD's request. And as -- again, our plans are designed to comply, and those engineering measures are what we reference to EPA and to EPD, that -- if up you take EPA's interpretations that we talk about here, we provided documentation to EPD showing how we comply.

Q. So you haven't changed any of your ash pond closure plans since EPD received that letter from EPA?

A. (Witness Mitchell) No, we have not, because we have continued to demonstrate how our plans were designed to comply.

Q. But you've known of EPA's interpretation for three years now and haven't changed a single plan. Isn't that too much -- too big of a risk?

A. (Witness Mitchell) Again, EPD is the regulatory authority in the State of Georgia in this space. EPD has consulted with EPA. EPD issued a closure-in-place permit for Plant Hammond in 2023, after consultation with EPA for over two years. And EPD has continued those discussions with EPA.

If EPD asked us to -- or requires us to add

additional controls or measures, then we will do what we need to to comply. And we've provided thousands and thousands of pages of information to EPD -- permit information, including those performance standard documents that I mentioned, that demonstrate how we comply.

Q. Have you quantified how much it would cost to change your plans if -- should EPD or EPA require you to change them?

A. (Witness Mitchell) No, we have not.

Q. Let me turn to page 13 -- or, actually, you might remember this because you just answered some questions. You reference, technical considerations and operational impacts on co-firing gas at Bowen and Scherer; correct? You mentioned you're conducting engineering studies on those?

A. (Witness Mitchell) Can you go back to --

Q. Page 13.

A. (Witness McNelly) Of testimony?

A. (Witness Mitchell) On 111?

Q. Yes.

A. (Witness McNelly) Okay. I'm there.

Q. You say you're conducting engineering studies to evaluate technical considerations and operational impacts of co-firing; correct?

A. (Witness McNelly) That's correct.
Q. Are you saying here that it's possible that you won't be able to co-fire gas at these units?
A. (Witness McNelly) We're not saying that. And, Commissioners, remember that the 111 rule for existing steam generators requires a state plan by the Georgia EPD. And so our considerations and our engineering studies are for us to help understand and scope what that would look like, but it is ultimately contingent on the Georgia EPD state plan development.
We do expect this will remain an option with the state plan, and we don't have any reason to think that we wouldn't be able to modify or choose that pathway for these units.
Q. So the results of the engineering study, it's impossible that they will say something like it's -- we can't co-fire gas at Bowen and Scherer, that's not what they're examining?
A. (Witness McNelly) I hate to use the word "impossible," but, no, that is not expected at all. In fact, we have evidence, as an earlier counselor asked, that -- of that conversion process at some of our units in the state as well as others on the fleet.
Q. Thank you.
Let me switch to ELGs. You mentioned that

it's a significant challenge to comply with ELGs, and you said earlier today that it's going to cost hundreds of millions of dollars. The controls first -- the controls you're referring to for ELGs are meant to protect water resources and human health; is that generally your understanding of ELGs?

A. (Witness McNelly) I think that's generally the intent of the rules, not sure that this one does more than what the 2020 rule has already got out there for us, and so our compliance with the 2020 rule is underway.

Commissioners, if you'll recall, there's work being done at both Plants Bowen and Plant Scherer to comply with the 2020 ELG rule. It is not a ZLD requirement, but it does require near-zero controls levels down to the constituents of concern. And so the treatment is very good under the 2020 rule.

The 2024 rule also requires that you keep going with that 2020 treatment equipment while you pursue the 2024 treatment equipment, and so those are both ongoing at this point.

Q. But you recognized in your testimony on page 7 that those controls are in the best interest of customers; is that correct?

A. (Witness McNelly) Controlling those units and continuing to operate those units is in the best interest of customers because it provides the most cost-effective way to meet compliance requirements and provide energy for this capacity growth.

Q. In 2022, it was the company's position that by complying with the 2020 ELGs at Bowen for two units, would make the whole plant compliant with the ELG use for 2020. Is that your position for the 2024 ELG rules as well?

A. (Witness McNelly) I wouldn't say it exactly like that, but I think the concept that you're getting at is accurate.

Commissioners, the ELG treatment system is sized. It's a common system, and it's sized for a worst-case max-flow scenario, and that includes a two-unit or a four-unit look. And so the equipment that we're installing, both for 2020, and what we anticipate installing for 2024, would cover the operation of either two or four of those units.

Q. Thanks.

MS. ARIZA: I'd like to introduce NRDC, SACE and Sierra Club Exhibit 1, which is the company's response to STF-PIA-4-15.

For the record, I'll give the court reporter a public disclosure version, but I'll show the panel the trade secret version.

(The documents referred to were marked for identification as NRDC/SACE/Sierra Club Exhibit 1.)

BY MS. ARIZA:

Q. Please let me know when I can ask some questions.

COMMISSIONER PRIDEMORE: Isabella, you've got extras, so give them to the court reporter. Those are trade secret. I don't want them going around.

MS. ARIZA: I'll get rid of them.

BY MS. ARIZA:

Q. This discovery response describes the capital projects that are required and the estimated costs associated with them for retrofits at Bowen and Scherer for the 2024 ELG rule; correct?

A. (Witness McNelly) Yes.

Q. You already said that -- and I'm not going to ask you about the trade secret numbers. You've already said those are in the hundreds of millions of dollars. Importantly, though, the table shows that should you retire these coal units before 2034, the dollar amount is zero; correct?

A. (Witness McNelly) Yes.

Q. Doesn't that mean that -- sorry.

That doesn't mean that it will be cheaper to keep them around, just that keeping them online longer will be more costs?

A. (Witness McNelly) I'm not sure I understand your question. Can you say it again, please?

Q. Sorry. Your investment -- your hundreds of millions of dollars invested in the ELG to keep them online beyond 2034, doesn't mean that -- you know, sorry. Strike that.

Did you quantify how much additional lifespan would -- this significant investment would buy for Bowen?

A. (Witness McNelly) My group, no. No, not that I'm aware of. If we did, it would be a different group that does that.

I think it's important to note that -- and Panel 1 noted this, but these resources are still cheaper and more economic for customers, even with the ELG investment, than building new units. And so the idea is that evaluation is run, and Panel 1 talked about it. Those are all considered, but the idea is that we're going to comply with the rules on the books and continue to operate these units because it's a better economic choice for our customers and still remains in compliance.

Q. As long as the load shows up; correct?

A. (Witness McNelly) I mean, I think that's an understood, but yes.

Q. How old is Gaston?

A. (Witness McNelly) I actually don't know the vintage of those units. I'm sorry.
Q. Does 1960 sound about right?
A. (Witness McNelly) I don't know. I think we can look it up.
Q. Thank you.
A. (Witness McNelly) Yes, 60's vintage.
Q. So Bowen is just a few years younger; correct?
A. (Witness McNelly) About a decade and a half. It's more than just a few years.
Q. Am I right that this discovery response says that you did not complete a study evaluating the extension of Gaston beyond 2025, given the age of the plant?
A. (Witness McNelly) Let me look.
Q. It's the footnote.
A. (Witness McNelly) Yeah, I see that. Yes.
Q. And the main panel testified that the company's currently conducting an RFP; correct? And that results will be available later this year?
A. (Witness McNelly) Yes.
Q. And part of the reason that RFPs ^under ways to seek generation to address unprecedented load growth; correct?
A. (Witness McNelly) Yes.

Q. The point of doing the RFPs to get the cheapest resources available -- one of the objectives of conducting an RFP, would you agree with that characterization?

A. (Witness McNelly) Most cost-effective. There's lots of things to balance, but certainly affordability is primary economic choice for our customers and is very important.

Q. And am I correct that if the RFP identifies resources cheaper than Bowen, Bowen might not end up being needed -- you might not need to dispatch it?

A. (Witness McNelly) That's really for Panel 1's expertise, but, no, that's not my understanding, that Bowen unit 1 is part of the request of this -- or part of our plan for the capacity growth, and my understanding is it's needed in any case.

Q. "In any case" meaning even if the IRP shows more cost-effective resources?

A. (Witness McNelly) I think the RFP is intended to show all the resources available, and the ones that will be selected are the most cost-effective, and I think it also includes the anticipated extension of those units being run.

Q. Okay. Thank you.

MS. ARIZA: No further questions.

CHAIRMAN SHAW: Okay. Thank you.

Southern Renewable Energy Association.

(No response.)

CHAIRMAN SHAW: Department of Defense.

(No response.)

CHAIRMAN SHAW: Walmart.

MS. EATON: No questions, Mr. Chairman.

CHAIRMAN SHAW: Redirect?

MR. MARZO: Yes, Mr. Chairman, just very briefly.

REDIRECT EXAMINATION

BY MR. MARZO:

Q. Panel, you were asked some questions earlier by GIPL counsel related to what she referred to as now GIPL Exhibit Number 8. It's called the Data Center Economic Development exhibit. Do you recall those?

A. (Witness McNelly) Yes.

Q. You were asked about the goal of Georgia Power, and I think carbon reductions and so forth, as part of that line of cross. And what I want to ask you: Is the IRP the forums where decisions will be made regarding resources that will be used to serve Georgia Power customers?

A. (Witness McNelly) No -- yes, I'm sorry.

Can you ask me that again? I'm reading this thing and not thinking.

Q. Okay.

A. (Witness McNelly) I really don't -- I need you to ask me again.

Q. Is the IRP the forum where the decision will be made regarding the resources that will be used to serve Georgia Power customers?

A. (Witness McNelly) Yes.

Q. Is it fair to say, to the extent that there are resources that are selected that result in reductions to carbon, those would be decisions made by this Commission?

A. (Witness McNelly) That's right. The Commission would make those decisions.

Q. And those decisions would be made when they're in the best economic value for our customers; is that correct?

A. (Witness McNelly) That is correct.

Q. Now, you were also asked some questions related to the transition away from fossil units to renewables. And I want to ask you: In this IRP, isn't the company still adding renewables?

A. (Witness McNelly) Yes.

Q. And still adding battery storage?

A. (Witness McNelly) Yes.

Q. And those are noncarbon-emitting resources as well; correct?

A. (Witness McNelly) That's right.

Q. You were asked by Sierra Club counsel about what is Sierra Club Exhibit 1. She asked you some questions related to -- I can't say Gaston the way she said it. It sounded a lot younger the way she said it, but Plant Gaston units, and I think she referred to them as 1960 vintage units. Do you recall those?

A. (Witness McNelly) Yes.

Q. Now, isn't it true that Gaston was converted from coal to gas in 2015, 2016 timeframe, due to the MATS rule?

A. (Witness McNelly) Yes.

Q. So Georgia Power -- is it fair to say Georgia Power customers have invested in Gaston in recent times to convert them to gas?

A. (Witness McNelly) Yes.

Q. Okay. And so by extending the life, are Georgia Power customers getting the benefits of said investment?

A. (Witness McNelly) Yes.

MR. MARZO: Thank you, Mr. Chairman. I think that's all the redirect that I have.

CHAIRMAN SHAW: All right. Thank you,

Mr. Marzo.

Well, I think we're going to get finished a little sooner than we thought. That's a good thing. I don't hear any complaints. But I'll ask the court reporter at this time to make all exhibits a part of the record.

And I'd like to thank everyone for their time and patience, and especially this last panel for moving pretty fast. And, Panel, y'all can be excused.

We hope everyone has safe travels, and, again, thank y'all for the time this week and the way that everyone's handled themselves, with the exception of about three people, but none in this room. So thank y'all, and we are adjourned.

(NRDC/SACE/Sierra Club Exhibit 1 was admitted into evidence.)

(Hearing adjourned at 5:55 p.m.)

C E R T I F I C A T E

We, Brenda P. Elwell and Kelley Nadotti, certified Court Reporters, do hereby certify that the foregoing transcript is an accurate record of the proceedings had in the above-entitled matter at the time and place therein set forth.

Kelley Marie Nadotti, RPR, CCR
CCR 6256-8388-8026-4192

Brenda P. Elwell, RPR, CCR, B-2023