PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Tuesday, September 26, 2023

TIME: 10:00 a.m. - 1:00 p.m.

DOCKET: M-100, Sub 163

BEFORE: Commissioner Kimberly W. Duffley, Presiding

Commissioner Daniel G. Clodfelter

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

Commissioner Karen M. Kemerait

IN THE MATTER OF:

Technical Conference

Investigation regarding the Ability of

North Carolina's Electricity, Natural Gas, and

Water/Wastewater Systems to Operate Reliably During

Extreme Cold Weather

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P R O C E E D I N G S

COMMISSIONER DUFFLEY: Good morning. Let's come to order and go on the record, please. I am Commissioner Kimberly W. Duffley of the North Carolina Utilities Commission, and I'll be the Presiding Commissioner today. With me this morning are Commissioners Clodfelter, McKissick, Hughes, and Kemerait.

Today we are conducting a technical conference in Docket Number M-100, Sub 163, In The Matter of Investigation Regarding the Ability of North Carolina's Electricity, Natural Gas, Water, and Wastewater Systems to Operate Reliably During Extreme Cold Weather.

Pursuant to the State Ethics Act, I remind all members of the Commission of their duty to avoid conflicts of interest and inquire if any Commissioner has any known conflict of interest with regards to the matter coming before the Commission this morning.

(No response.)

Let the record reflect no conflicts were identified, so we will proceed.

On January 3rd, 2023, Duke Energy

Progress, LLC, hereinafter DEP, and Duke Energy Carolinas, LLC, hereinafter DEC, appeared before the Commission to present information on the load reduction event that occurred on the DEP and DEC systems on December 24th, 2022, due to Winter Storm Elliott.

Subsequent to that presentation, the Public Staff has conducted an investigation into the circumstances underlying the event and has engaged DEP and DEC in several rounds of discovery.

On August 7th, 2023, the Commission issued an Order scheduling a technical conference for today to receive updated data and information from DEC and DEP as to the December 4th, 2022 [sic], load reduction event and to receive the results of the Public Staff's investigation of the event. The Order further required that the Public Staff, DEP, and DEC, appear at this technical conference to respond to questions from the Commission.

This -- the proceeding this morning is being transcribed. The transcript will be filed in the Docket as soon as it is available.

Before we begin, I'd like for the parties to identify themselves for purposes of the record, and we will begin with DEP and DEC.

MR. JIRAK: Thank you very much, Presiding Commissioner Duffley. Jack Jirak on behalf of Duke Energy Progress, Duke Energy Carolinas. I'm joined by a panel of -- of subject matter experts from Duke who will be presenting to the Commission. Ms. Kendal Bowman will be introducing them at the beginning of her remarks.

COMMISSIONER DUFFLEY: Thank you.

MR. JIRAK: Would you like just to go ahead and have each panelist introduce themselves at this time?

COMMISSIONER KEMERAIT: Yes. If everyone will introduce themselves and the Public Staff -- we'll let the Public Staff introduce themselves and then begin with Ms. Bowman.

MS. BOWMAN: Good morning. I'm Kendal Bowman, the North Carolina State President for Duke Energy.

MR. PEELER: Good morning. I'm Nelson Peeler, Senior Vice President of Transmission and

Fuel Strategy and Planning.

MR. HOLEMAN: Good morning. Sam Holeman, Transmission System Planning and Operations.

MR. GILLESPIE: Good morning. I'm Preston Gillespie. I'm Executive Vice President and Chief Generation Officer.

MR. GRANT: Good morning. I'm Eric Grant, Senior Vice President of Customer Delivery Carolinas.

MS. SIMS: Good morning. I'm Taryn Sims, Vice President of Marketing, Insights, and Customer Engagement.

COMMISSIONER DUFFLEY: Good morning to all.

MR. JOSEY: Good morning, Commissioners. Robert Josey, on behalf of the Public Staff representing the Using and Consuming Public of North Carolina.

MR. METZ: Dustin Metz, Public Staff, Engineer.

COMMISSIONER DUFFLEY: Good morning to you gentlemen. Ms. Bowman?

MS. BOWMAN: All right. Good morning,

Commissioners, and thank you for your time today. We really appreciate the opportunity to provide you an update on the actions that we've taken in response to the December 24th load shed events that occurred due to Winter Storm Elliott. In addition, I would like to thank the Public Staff for their engagement this year as they independently investigated the December 24th event.

We look forward to hearing the Public Staff's remarks and appreciate the thoroughness of their investigation. As we stated during January 3rd report to this Commission, Duke Energy did not take the decision to implement the load reduction plan lightly. We deeply regret the impacts it had to our customers. We recognize the critical importance of providing reliable service to our customers.

And as you hear today, we left no stone unturned as we seek to reduce the risk of another load shed event. Across the entire Duke Energy enterprise, we have been thoroughly reviewing the causes of the event and establishing new procedures in ways to address the issues that were identified.

Today I am joined by five of our company leaders that will discuss the specific lessons learned and corrective actions taken by their organizations in response to this load shed event.

So Nelson will describe the updates to our weather and load forecasting tools and processes. Sam will discuss the ways in which we have augmented our internal mobilization notification and winter preparedness procedures. Preston will describe enhancements to our generation fleet. Eric will describe the testing and validation of the rotational load shed tool. And Taryn will address improvements to our customer communications during emergency events.

Again, thank you for the opportunity to be before you today. We look forward to a productive and engaging discussion. And with that, I will turn it over to Nelson.

MR. PEELER: Thank you, Kendal. Good morning again. As Kendal said, I'm going to talk about the review and actions that we've taken since December. Specifically, in the areas of load forecasting and day-ahead planning for -- planning reserves for short-term planning.

Since December, we have reviewed processes, models, tools. All the things associated with forecasting to look for opportunities for improvement. Specifically, there are 12 actions identified in these categories. And those actions are really focused around the process and organizational awareness, forecast model enhancements, metrics, and assessments, as well as understanding of customer load profiles.

Ten of these identified twelve actions have been completed. The two that still are outstanding -- one is really an ongoing action. It's a -- it's a continuous process. And then the twelfth item is a software upgrade that we're waiting for in the fourth quarter of this year from the vendor.

While continuous improvement and forecasting is very important, identifying and planning for uncertainty in the forecast is even more critical. So I'll spend some time talking about that as well. So I'd like to share, you know, specifically today, of these twelve areas, I'd like to talk about forecasting enhancements, benchmarking with our neighbors, the -- the grid risk assessment team process that we formalized, and then some dynamic adjustments to our day-ahead forecast. Jack, can you go to the next one, please?

So I'll start with forecasting enhancements. Immediately following the December event, we -- we updated our forecast models with the loads that we observed in that event. If you'll recall from our previous discussion, the forecast tool we use is a regression model. So it learns from experience.

So the immediate introduction of those new loads into the tool gave it knowledge, made it learn, made it smarter, and gave it the ability to better predict cold weather in the future. Additionally, we immediately had the vendors validate those additional loads.

And the vendors also gathered information from other customers who experienced similar load situations during the December event across really much of the southeast United States during that cold weather event. That definitely improved the ability for the tool to forecast colder temperatures.

Additionally, analysis was performed on how back-up heat, or heat strips associated with heat pumps, performed during this event. Learning about the -- the way these resistant loads performed during different temperature events was important to incorporate into our model. And what we've been able to do is incorporate some different inflection points in this regression curve. So that, at certain temperatures, essentially, it changes the slope of the regression curve.

So at certain temperatures, multiple heat strips come into affect, and they change the load profile that's produced by our customers. So learning about the customer load behavior is very important here. So we've introduced some additional inflection points into our model so that it knows that different temperatures, say 35 degrees -- it changes the slope of that regression curve to help us better predict what happens when it gets really cold.

Additionally, while doing that same research, we were able to also add some breakpoints for -- for cooling degree days. So similar for summer improvement of load forecasting as well. Also, we're in the process of determining a separate linear regression tool that would run as a supporting forecast.

It does not -- it actually doesn't take into account history quite as much. It allows the tool to forecast some extreme days. So it doesn't -- doesn't say, "Oh, that's a tail event," and just not weight it as much. It allows the tool to produce an extreme forecast. So we're using that in parallel with the current regression tool.

And then the other thing I'll talk about a bit is we're investigating some bottom-up forecasting that can use customer load data and other data to feed into this tool to give us a better forecast for customer load behavior. I'll talk about that on the next slide a bit.

Bottom-up forecasting would be a compliment to our current regression tool. By using bottom-up forecasting, we can actually get more granularity into the model and introduce load behaviors that are not uniform across the large geography that we have. Today we take -- we essentially use three balancing authority area load forecasts, roll those up and combine them.

Bottom-up load forecasting would allow us to segregate that into more regions and have a more granular view. So it looks like the box is a little hard to see, but there's a pyramid on the -- on the slide that -- at the top of that pyramid is the current approach where we use the three input load forecasts. What we're talking about is expanding that. It can be expanded down to a geographic region.

So think, maybe 30, 40 different regional geographies in the Carolinas. It can be expanded down to a substation or a feeder level. That would be thousands of inputs. And even potentially down to a meter level input, which would be millions of inputs. So we're currently working on, you know, how to do this -- how to incorporate that into the regression tool, and what the right level of granularity is.

We're going to start with that 50 or so

input. And may ultimately build down to the -- the larger billions of inputs, but we've got to determine the right -- what the right value proposition is for accuracy. It may not be millions. It might be hundreds so -- but we're moving forward with -- with incorporating that into our forecasting process. Next slide, please, Jack.

Another specific action that -- that we embarked on after December was benchmarking with others. We benchmarked with our neighboring utilities and RTO on their experience during the December event. As well as what types of tools they used, what types of results they achieved, any improvement opportunities that they identified. How they might account for customer behavior -- all those types of things.

What we essentially determined from that feedback was most had very similar performance. All were using regression tools. The majority were using the same regression tools that we were using. There was some variation. The -- the range of forecast error on December 24th was some were a little less than ours, and some were a little more. So we were sort of in the middle.

And the number of resources and the weather forecast, all very similar to the approach we were using. The one significant thing we picked up, we did find one utility that was starting to use some bottom-up forecasting. And they identified a vendor that they were using, and we'd been pursuing the bottom-up forecasting that I previously talked about. So that was the nugget that we took away from the benchmarking with our neighbors. Next slide, please, Jack.

I mentioned the grid risk assessment team. Following the December event, one of the things we looked at was our current approaches to how we identified risk or uncertainty in a forecast. How it was communicated internally so that we could prepare and make folks aware. What we generally found was that we had the actions in place to do that effectively, but it wasn't formalized. It wasn't proceduralized. It wasn't a hundred percent clear exactly, you know, who's communicating.

And so what we've done is taken, really, a lot of the actions that were part of our normal planning process, but we've formalized them in what we're calling a grid risk assessment team process. And this grid risk assessment, it adds rigor to our review. It adds rigor to our discussion and the communication of the uncertainty that exists in the forecast either for the supply or demand-side issues.

And so -- any time we, you know -- I'll give you some examples here -- some things that would trigger a grid risk assessment team. If we have forecast of reserves below our target. If we have abnormal temperatures or storms. Any type of fuel issue that might affect our generation output. Unplanned or emerging generation issues and regional grid conditions.

So if our neighbors are having challenges, all of those things would be something that would trigger a grid risk assessment team. The grid risk assessment team, like I said, is formalized. It's made up of a cross-functional group. It -- really, for -- everybody sitting at this table is representative in that grid risk assessment, and the team has a formal, you know, approach to meeting.

They evaluate the uncertainties and risks, and they develop mitigation plans. I would say 90 percent of the time, the grid risk assessment team is able to develop a successful mitigation plan, and we move forward with a, you know -- a normal day of operations. In the event that it can't resolve it with the mitigation plan, it escalates to what we call a grid threat need. And Mr. Holeman will talk about that a bit.

But it would just be the next level of -- of action, if you will, for -- kind of moving from planning into action. To take steps to ensure we have adequate reserves and a reliable operation.

The other key component of the grid risk assessment is a formal communication to affected internal parties and executives so that everyone is aware what risk was identified, how it was mitigated, and the system status. Next -- next slide, please, Jack.

Another key -- I mentioned this in --

in my opening remarks that an important piece of being prepared to operate reliably is recognizing and planning for uncertainty. No matter how hard we work on the forecast, the forecast is still a forecast. There will be uncertainty in the forecast. And so planning for uncertainty in both the supply-side and the demand-side of our forecast is very important.

It's growing in importance as we forecast the supply-side with more variable resources as well. This is a challenge that's going to grow for us in the future. We've implemented two -- two additional things into our seven day-ahead plan. And we've introduced an uncertainty metric for supply-side and an uncertainty metric for demand-side.

And this shows up as a dynamic reserve number in our day-ahead reserves. So Mr. Holeman will talk a bit about day-ahead reserves. Day-ahead reserves are essentially a component of planning for uncertainty. That's why they're there. They're -- they're, you know -- they're created to deal with uncertainty of generation performance, of load forecast error, other uncertain things. So what we've -- what we now have in place is a dynamic reserve adjustment that goes into our day-ahead planning reserves. I'll describe those just briefly.

So from a -- from a demand-side standpoint, this is uncertainty in generation output. So that could be, you know, a unit that's -- that's challenged to perform. It could be a solar forecast that's uncertain. Anything on demand-side. So we're now calculating, in our seven-day report, an uncertainty of generation performance.

This is a stochastic algorithm that's based on historical generation performance and load forecast, and it predicts in megawatts what the risk of that generation performance is. But this gives us a megawatt number to consider against our reserve target. So we can say we have 1700 megawatts of reserves but there's 200 of it that's risky. And so that helps us understand where we actually are positioned from a data reserve standpoint.

Similarly, on the -- on the forecast -- the load forecast side, we're doing a very similar thing with this stochastic algorithm that uses historical weather data and historical load forecast data to train this algorithm so that it can give us some indication of how -- how much potential risk there is in the load forecast.

So, for example, thunderstorms coming through at different times of the day impact our ability to forecast. Fronts moving at different speeds, impact our ability to forecast. This algorithm lets us see in megawatts an indication that, you know, our -- our load forecast is a certain number, but it could vary by 300 or 500 megawatts.

Using those two additional numbers gives us the ability for the grid risk assessment team, or others who are in the day-ahead planning process, to evaluate the risk we have in our plan. This is a very important tool for us. And I think it will be even more important as we go through our generation transition because there's more uncertainty in both supply-side and generations-side.

COMMISSIONER DUFFLEY: Mr. Peeler --

MR. PEELER: Yes.

COMMISSIONER DUFFLEY: If I could interrupt just for a second to level set for everyone. Are all of the actions that you're discussing in response to the December 24th, 2022, event? These are new processes that the Company is putting into place and establishing?

MR. PEELER: They are. These are -- after December, we -- we went back and reviewed everything we do about forecasting and day-head planning. And these are the specific actions that we identified.

COMMISSIONER DUFFLEY: Okay. Thank you. You may continue.

MR. PEELER: And -- and really, that wraps up the component that I wanted to talk about. But it predominantly is continuous improvement on load forecasting, as well as recognizing uncertainty and putting uncertainty in front of people so it can be discussed and planned for. That's kind of a summary of where I'm at. And with that, I'll -- I'll pass it on to my colleague, Mr. Holeman.

MR. HOLEMAN: Thank you, Mr. Peeler. Good morning, Commissioners. What I want to do is -- is review eight of our primary post event actions from an operating perspective. I'll be building on the information that Mr. Peeler just -- just shared with you. If we could advance the slide. Thank you.

So -- so the first issue was with the day-ahead planning margin as Mr. Peeler just talked about. And looking at it, is it -- is it consistent in the way it's done? How does it compare with our peers? And so we continued to look at our day-ahead operating reserve margin from a calculation perspective. That's where we started.

Keep in mind that operating reserve is a NERC term. It means the capacity above your firm demand that can be used for load forecast error. It can be used for generation scheduled or unscheduled outages, or for local protection, or for pretty much anything else that may come up operationally. It's, basically, a toolbox for the operators to use to deal with uncertainty as Mr. Peeler referenced a minute ago. It includes both spinning synchronized resources and non-spinning resources.

Typically, non-spinning resources are resources that are offline that the operator -- system operators in our energy control centers can call on. So as we benchmarked with our peers, our first question was, what's your basis for your calculation. And then we determined that we are very consistent with our neighbors. We did this through the VACAR group -- Virginia/Carolina's Reserve Sharing Group.

We also reached out to our other neighbors to validate their -- their approach to calculation of day-ahead operating reserve. And the framework for that calculation is based around, really, three parameters.

One, is your largest unit in your balancing authority, your typical load forecast error, and what is your typical rate of change of your load? How does your load ramp over the course of the day? So data that -- that you plug into the equation, which we believe is consistent with our neighbors, is going to be different because different size units, different ramping patterns, different load -- load forecast errors. But we believe that the process that we have in place is very consistent with our neighbors based on the benchmarking we did.

Now, adding on to that as Mr. -- Mr. Peeler just referenced, we've added these risk-informed components around load forecast error and generation availability. So we report that out to the folks that deal with this -- the planning and the operating of the system, both in the Energy Control Center and the unit commitment function. Those are -- those are additive to our reserve requirements.

So they take into account risks that we may face with -- with low forecast errors, extreme weather or -- or generation availability questions that we need to encounter. So those are additive to our -- to our levels of -- of adequacy. We have a draft procedure in place. It's been signed off, and we hope to have it finalized. We will have it finalized by the start of the winter of '23-'24.

Action two had to do with our general load reduction plans -- the GLRP plans that we filed with the Commission, both from a DEP and DEC perspective. The issue was they are not very consistent from look and feel and from a content. And the potential is, that can be confusing to stakeholders that are looking at these general load reduction plans.

I can assure you there is no confusion within the ECC. Our system operators train on their specific tools, their specific plan. And so there's no confusion in -- within the control center -- to the decision makers. But we recognize the -- the -- the differences could create distractions.

And so what we've -- we've started to do is convert both the DEC and the DEP general load reduction plan, GLRP, to a common format -- to a common look and feel. Now, internally, they will still be different because the balancing authorities are different. But -- but they will be much more consistent in terms of the look and the feel of the documents.

Those will be changed. And when we file those GLRP documents in 2024, they will be updated with the new -- the new look and feel for those -- those programs. But there will be -- there will be differences in -- in the inside of the plan. Mr. Jirak, if you can -- Page 4. Thank you.

The next two items have to do with our interface with our network customers. Those are our customers that have a relationship with us through our open access transmission tariff. And I think conclusions on the review of this event show that this is an area of definite improvement. We've identified all the organizations that qualify as a network customer under the tariff, and we are building, using a existing technology, a process through which we will communicate to them any kind of change in grid status, especially as we enter the NERC energy emergency alerts.

And we will -- we will use a proven communication technology that does phone call, text, and -- and -- and e-mails. And they are going to responsive, operationally-focused people in these organizations so that they can take action. We -- we are -- we will be drilling this process before the start of winter of '23-'24. And this links back to the -- to the grid risk assessment process that Mr. Peeler referred to.

That is a -- that is a process, and it involves our wholesale customer group. That is the group within the Company that -- that works with our wholesale customers daily. And so they are a part of both the grid risk assessment process and the grid threat process. If we could page forward, please. Thank you.

The next one is, generally, how do we become more nimble in communicating grid risks both internal Duke and to our external stakeholders. And Mr. Peeler spoke of the grid risk assessment process and the grid threat process. So these have been formalized with -- with rigor from -- from an enterprise perspective. We're going to use tools that other parts of the Company use for emergent type of -- of situations.

But we've -- we've had -- we're building on a process that we've used in the past. The term we used was a "tailgate process." But we've changed that process into the grid risks process and the grid threat process using proven enterprise communication tools that will send e-mails, will send -- will text messages, and phone calls to the members of these groups, making sure that they are attending the calls, and it requires a response.

Now, we monitor the grid at all times by a group of system experts that go from system operations, economic dispatch, unit commitment, reliability, coordination, generation, corporate communication. And when the triggers Mr. Peeler referenced are met, it starts a grid risk assessment review. And then coming out of that, if -- if the -- if the grid threat is -- is identified, then the grid threat process will be started, and that will roll out. Okay. Here's where we're at. Here's what we're going to do to deal with it. And -- and we have rolled that out.

We have used it some 17 times since we made that transition from the tailgate process to the grid threat process -- grid risk assessment process at the end of 2024 started 20 -- excuse me, '22 and started 2023. We've had 17 grid threat -- or excuse me, grid risk assessment meetings. And out of that we've had -- we've had 6 grid threat calls. And the process worked well. It allowed us to work through our options. We were able to communicate outwards, and we were able to work through the situations over the -- over the course of the summer.

We are also conducting our winter of 2023-2024 challenge board call on 10/10/23. We started those back in the aftermath of polar vortex in 2014 and 2015. This helps us -- as we make the turn from summer to winter, it allows us to sharpen our focus on the upcoming winter with opportunity and time to make adjustments to check and adjust, if you will.

As we saw in Winter Storm Elliott, communication coordination is more challenging in the winter than it is in summer. The run up to the peak, and the peak happened in the early morning hours. And the peak is usually 0700, 0800 in the morning. In the summer, you have the whole day to -- in the run up and in the crossing the peak -- to communicate and coordinate. We believe that the processes we have put in place, and Mr. Peeler described, have worked well for us in 2023. And we will continue to update and expand those as we move forward. If you can move to the next slide, Mr. Jirak.

So the final two actions -- one is GLRP training. We conducted a cold weather load shed tabletop drill that included all of the -- all of the internal GLRP stakeholders. That was conducted on 8/10. We've identified actions. They will be rolled out to the appropriate responsible parties to those actions by the end of the month. And then as I spoke earlier, we will follow up with our winter 2023-2024 challenge board on 10/10. All of that pointing towards our readiness for the winter of '23-'24, and it gives us time to respond to it.

The final action was a Winter Storm Elliott lessons learned from load shed training. We've incorporated the lessons learned from -- from the load shed experience on Winter Storm Elliott on the 24th in both our energy control center training with system operators and our distribution control center training with the -- the 24-by-7 operators there. We do that in an integrated fashion.

We do it separate, and we also do it together. Those training sessions will be completed by the start of the winter. This is an ongoing process. We do this preparation before the summer. We do it before the winter. We evaluate and train both on the automation, the load -- the load shed tool -- the rotating load shed tool, and the manual tool so that our operators and both the DCC and the ECC are prepared for whatever situation that may came -- that may come up.

So readiness for peaking season is an on-going process. We're always in the process of preparing for the next peaking season. We're always in the process of preparing for the next day of operations. And so we continually are moving towards getting better at what we do. And part of that is taking operating experience, not only from the industry, but also from Duke Energy -- our experience with Winter Storm Elliott, for example -- and plow that into our preparation. I believe -- well, I don't believe, I know that our enhanced processes that Mr. Peeler referenced and I referenced have -- have positioned us better based on our experiences this summer.

Those processes worked really well, and we will adapt for the winter. And we will continue to work to make those processes work to ensure reliability and security for North Carolina customers and communities. I'll now turn the mic over to Mr. Preston Gillespie.

MR. GILLESPIE: Thank you, Sam. Just as a recap, on the night of the load shed, we had 10 of our 11 nuclear units were in service. 11 of our 15 call units were in service, and 8 of the 9 combined cycles were in service. So around 32,000 of our 36,000 megawatts of generating capacity was in operation. During the night, we lost around 1300 megawatts, and it was predominantly due to two causes as we went back and did the analysis.

First cause was heat trace. We wrap a -- we wrap an electrical-resistant heat around key and critical instrumentation lines. And this heat trace is designed to keep any of the fluid in these lines, and liquid -- not allow them to freeze. And we found in some cases that -- that we had lines that had heat trace that was either missing or not functioning to its full capacity.

The second area we found were gaps in our piping insulation. So we insulate pipes. Some of these same lines would be insulated and heat traced. And when we went back and looked, we had -- in a few cases where either insulation had pulled apart or where repairs had been done and the insulation had not been installed completely.

Now we do walk downs. We do inspections. We went out and looked for a heat trace and heat -- I mean, for insulation integrity. And what -- what we learned was in our walk downs, we were walking down all of what I would call "accessible areas." We were not necessarily climbing up into the roof tops or going into inaccessible areas that were not -- not immediately available to the operator. So these are some of the -- these are some of the actions that we will -- we will modify as we move forward.

All the heat trace and all the insulation issues that we found at these four operating sites either have been, or will be, repaired by the -- by cold weather season. And the simple repairs are done. But we're doing some upgrades and modifications to improve our -- our heat trace capacity and capabilities, and heat trace the monitoring of the operation of the heat trace capabilities. Some of that work is still in flight.

If we look at the -- I'll go to the next slide, Jack. If I look at the other key actions that we're taking, your -- first of all, outage optimization. So making more energy available, more of the time. So we're looking at when we take units out of service, when we start an outage season, when do we end an outage season. And those -- we call those shoulder months, by the way. When we perform our outages, we do these in shoulder months.

Weather doesn't always cooperate with us. So we're trying to keep outages out of December. In fact, this year, by the first week in December, we'll have all our outages complete. So we do that by backing up. Now, I will tell you, we've had a very warm September. So the first week, we took some of these plants out, and September was warm. We had to go back and evaluate capacity and needs with -- with Sam and Nelson and their teams to make sure that those plans could be executed as -- as they were laid down.

Also, shorter outages -- just finding way to -- to better coordinate, better lead the execution of our outages such that we get into and out of the outage quicker so that the facility can have greater readiness and availability. We've assigned a seasonal readiness coordinator at each of our sites. So we're going to put -- we're going to allow one individual to be accountable for that site -- for all the seasonal readiness actions.

It's a big job to get ready for seasons. And it's -- and what's interesting about our seasonal readiness activities is oftentimes you're performing wintertime readiness when it's hot outside. And you're performing summertime readiness when it's warm outside. So you're -- you're almost a season ahead as you go through these. And what -- what we find is that by placing a greater focus and a greater accountability on -- with -- with a person, that we will get better outcomes on ensuring that all our readiness actions are complete.

And, also, just implementation of lessons learned. There were a ton of things that happened across the operation during that night and other times during the winter, that never had impact on our ability to serve the customer. And never had impact on our ability to deliver energy to the -- the energy to Sam's folks that they need to serve the customer.

However, there were real issues that needed to be -- to be done. So, for instance, how we work on pieces of equipment. Air dryers is a great example. Air compressors. We use copious amounts of air in the operating -- in the operating power plant. That air, if it's not dry, could freeze up and cause instrumentation reliability issues. So we've gone back and improved our preventative maintenance activities -- improved training.

And then, also, the things that we need to keep the power plants running -- reagents, chemicals and the like. We've improved methods for ensuring availability of those. So although there were no consequences in this case, we did capture each one of those and have implemented them into our operating protocols to improve the operation for greater reliability.

And then, finally -- on the next slide, Jack. We performed benchmarking. We benchmark our peers. Specifically, with Southern Company, the Tennessee Valley Authority, American Electrical Power, Dominion. And we -- shortly after the -- after the 22nd, we met with all of those teams and -- and shared both lessons learned, and also what -- what went right for each other. So we grabbed the good things that we did as well in those -- in those interactions.

And so out of that benchmarking, we have a number of actions that we're following up on that will improve the reliability of the -- of the operation.

And then, finally, nuclear. Nuclear operated extremely well through the -- through this cold weather period. But there were lessons learned with the -- at the nuclear sciences also. And we've captured those operating -- those operating experience items and have incorporated those into our operating protocols.

As we look forward, I would tell you that we're also using new climate projections into -- that we have and integrating those into our operational readiness procedures.

And then, finally, just -- at the senior level -- senior level oversight, we have -- we have put in place what we call a bulk electric system oversight board. We'll -- we give it a name that's an acronym, but that's what it means. So we look -- this board looks at all things grid. From top to bottom, from left to right -- so reliability, security, resource. And this board -- it has -- I have peers on this board. My peers on the board, senior VPs, are on the board -- we report the outcomes of these board meetings to our CEO.

So you heard some of the work that's going on in the organization with how we explore grid readiness, how we make sure that the grid is ready to operate at a -- at a higher level. We provided oversight to the outcomes that -- that these teams do and looked forward into the future to ensure that the -- that the grid is -- remains safe, remains reliable, and remains available for all of our customers. So I'll turn it over to Eric.

MR. GRANT: Good deal. Thank you, Preston. Good morning, Commissioners. This morning I'm going to speak specifically to the issues as well as the improvement opportunities regarding our rotational load shed tool. It is referred to as RLS tool for short. Next slide, Jack.

Yeah. So just to recap, the RLS tool is used by distribution control centers and allows the DCC operators to shed a user-defined amount of megawatts. The RLS tool will automatically shed those megawatts using a prioritized list of circuits. The tool will then maintain that amount of load shed by automatically energizing -- de-energizing additional circuits and then restoring those that had been previously been de-energized. For those circuits that are de-energized, we target those circuits to be off no more than 15 to 30 minutes at any one time.

Unfortunately, on December 24th,

though, both the RLS tool and DEP and DEC did not perform as expected. And moreover, the tool -- the issues that we experienced were not similar in both DEP and DEC. In DEC, the RLS tool did successfully de-energize 350 circuits, and that equated to about 1000 megawatts of load shed. However, it incurred latency issues with respect to restoring circuits.

So what do I mean by latency issues? Well, instead of a circuit being restored every 15 minutes, when it was a time for a circuit to be restored, an additional minute was added to the targeted restoration time. So for the first circuit to be restored, it would have targeted 16 minutes versus 15. For the second circuit to be restored, it targeted 17 minutes instead of 15. So by the time you got to the 90th circuit, the tool -- it actually added an additional 90 minutes on to that 15 minute targeted restoration time.

So, of course, that delay -- that resulted in circuits being off longer than expected. It introduced cold load pickup issues, and that drove us to have to do manual restoration with respect to some of the circuits. And, of course, that kept customers out longer than you would expect.

In DEP, the tool did successfully de-energize 110 circuits, which resulted in about 600 megawatts of load shed. It did stop working, though, however, to issues associated with the tagging function. So with respect to rotational load shed, the tool does automatically put an info tag on every breaker that it opens as part of de-energizing that circuit. When it's time to restore that circuit, that info tag is removed from the breaker prior to it automatically being reclosed. On the morning of the 24th, the volume of the tags, basically, overwhelmed the tagging system, which in turn caused the RLS tool to cease functioning.

So in light of these issues, we've taken a number of steps to ensure the RLS tool will inform -- will perform as expected if it's called upon in the future. Next slide, Jack.

So what are those steps? Based on discussions with the vendor, both the latency issue that we experienced in DEC, as well as the tagging issue in DEP, were caused by software deficiencies. Both -- both the DEP and DEC RLS tools have been updated with the proper software, and it has addressed both of those issues. On top of that, we -- we now hold weekly meetings with the vendor of the RLS tool to make sure we're aware and stay abreast of any industry issues, as well as any software updates or patches that are needed to be deployed.

Also, as part of our enhancement effort, we've introduced more rigorous testing protocols to identify any issues that might have previously went undetected. Prior to the 24th, we test -- the testing of the RLS tool, basically, it -- we did so with 24 scenarios. Those scenarios would last anywhere from one to two hours in duration, with a maximum load shed of 200 to 300 megawatts.

After the 24th, those tests now consist of 84 scenarios compared to the 24. Some of those last in duration of up to 12 hours. And now we actually do a load shed test using a maximum load shed of 2000 megawatts. Some of the scenarios that -- some of the examples of the scenarios that we actually test now, that includes failing other systems while the RLS is running, such as the alarming system and the tagging system.

We actually run the test now with them without voltage reduction. We'll go in and actually change the times that a customer is expected to be out, say, from 15 minutes to 60 minutes. And we'll also pause the SCADA system to make sure that when it's restored, the RLS tool will actually come back and operate as expected as well.

We've also enhanced the testing environment. We now have a full scale environment that mirrors our production environment. That allows us to increase the volumes and durations of our scenarios. It also includes the same data integrations and complexities as our operational environment.

And then lastly, we've enhanced training with respect to our RLS tool. We've increased the population of those that are trained and now includes DCC supervisors, our operators, as well as back-office personnel, which would be folks like grid management, grid engineers, our DCC operators. Their training now includes classroom training, as well as simulator training. And I will say, we are better prepared and equipped if we're to resort to manual load shed now. That's part of our annual GLRP drill.

So, in summary, we do acknowledge that load shed is a serious decision. And as my colleagues have alluded to, we've taken a lot of steps to make sure the likelihood of that is low in the future. But if faced with having to shed load in the future, we do feel like we've taken the right steps in order to make sure the RLS tool will perform as expected going forward.

And with that, I will turn it over to Taryn Sims who's going to speak to our enhancements with respect to customer communications.

MS. SIMS: Okay. I will wrap us up today with that overview that Eric just mentioned -- of improvements that we've made in our customer communication space.

So immediately following Winter Storm Elliott, we pulled together a dedicated team to focus and -- and do a look back at what we communicated, and how we could do that better given the circumstances. So if we did find ourself in this position again, that we could get our conservation messaging out very quickly, and make sure that it's appropriate for the type of event that we're experiencing, whether in the winter or the summer.

Also, if we found ourself with this unique set of circumstances, and we needed to get messages out quickly, as -- as we were shedding load, we have updated our automated messaging platform to reflect messages that are specific to the type of event that we're experiencing. So that would replace our typical outage alerts that go out to customers that the customers are used to seeing -- that go out via text, e-mail or outbound calls. So those would very much be useful to customers because today we see that we have quite a few customers who receive those messages.

I believe earlier this year when we came, we talked about how many folks are auto-enrolled in -- in that program. We've now increased the -- those customers who receive the messages up to close to 90 percent of our customers who we have either a phone number or e-mail address for so that we can reach out to them very quickly in the event of an outage.

We also developed a comprehensive plan to educate customers more on what to expect, in general. So videos were created. We also -- we also deployed newsletters to our customers in addition to promoting our demand response programs and focusing on grid resiliency work. So all of that has been done over the course of -- up to now, and we'll continue to do that as we go into the winter months.

And with that, I will wrap this up today, and we can take any questions.

COMMISSIONER DUFFLEY: Thank you. I'm sure that we have several questions. I'll go ahead and get started with Mr. Holeman. And do you -- do you have a copy of the South Carolina report --

MR. HOLEMAN: I do.

COMMISSIONER DUFFLEY: -- at the table? Okay. I'd like to move to the -- the causes of the customer outages that begins on Page 17. But I'm going to jump around a little bit. I'd like to go to Page 36 of that report regarding network customers.

MR. HOLEMAN: Page 36?

COMMISSIONER DUFFLEY: Yes, sir.

MR. HOLEMAN: I'm there.

COMMISSIONER DUFFLEY: Okay. So you explain, in cause number four, the network customers. And I just want to drill down a little bit and understand the current rules and regulations with respect to network customers. And, specifically, what changes are being made.

I heard you state today in your presentation that you're working with the network customers, and you're working on communication technology. And I'd like to know what that looks like. But more importantly, how does that communication actually resolve the issue here?

And so as I -- and first, let me level set and make sure I understand what the report states. So, as I understand it, a network customer who had contracted with an independent power producer, lost the independent power producers generation tripped, and they -- they lost that service.

And so DEC provided that power to the network customer pursuant to the procedures and pursuant to the OATT. Am I correct in that assessment? Which -- which affected production that could have gone to other DEC customers?

MR. HOLEMAN: Subject to check, I believe that is correct.

COMMISSIONER DUFFLEY: Okay. So had that independent power producer not tripped, could DEC have avoided this load shed event?

MR. HOLEMAN: It would not have been enough generation to avoid the load shed event.

COMMISSIONER DUFFLEY: Okay. Thank you for that. And then, with respect to -- if we ever get into this situation again within North Carolina, is the Company looking at, or does it even have the ability, to change the terms of the OATT with respect to curtailing that network customer?

MR. HOLEMAN: So -- so I'm not an expert in the -- in the Open Access Transmission Tariff, but what we're trying to do is, one, become more nimble and agile in communication with those customers. All of them. And work with them to let them know, okay, we're in this grid status. We're approaching an EEA-1, EEA-2, EEA-3. If you recall, EEA-3 is we're on the verge of load shed. And in the -- in the -- the direction to them -- the operating instruction to a network customer will be stay in balance because they've got their own obligations.

It's a balancing authority. We're looking at the balancing authority load. We really -- as a balancing authority, we don't recognize the different customers. We're looking at the overall balance of the footprint. And so our instruction to them would be balance your load with generation resources.

And we are working through the process through which that would actually be executed. And that's part of -- part of the -- the -- that's part of the relationship we've got to establish with network customers -- a clear understanding of how that would work.

COMMISSIONER DUFFLEY: And you were talking about this communication. I assume within that communication, that the network customer had demand response programs, load -- their own load reduction programs that you would have visibility. You're trying to increase that visibility as well.

MR. HOLEMAN: What we'd like to happen, if we could, you know -- this is -- this is kind of the vision. As we progress through our programs, demand-side management, customer response, they're doing the same thing. We're doing this together. In sync with each other as we go through it. And the Commission knows the challenges with the timing of all this on December the 24th. A holiday early in the morning.

That's where I think the grid risk assessment process and the grid threat process and some of the things we're doing in terms of adding those -- those operating reserve triggers that increase the operating reserves -- we can do this more proactively. So we're not sitting there at two in the morning, four hours away from the peak, trying to get people to operationally respond.

And so that's part of the work we're doing with our network customers. We need contact information that are operationally responsive. Some of our customers -- network customers -- are very sophisticated in that space. Some of them aren't. So we've got to work with them to identify those operationally responsive contact numbers and -- and e-mails so that -- so that when we give them an instruction or give them an update on status, they can take that and make adjustments and help the situation. I hope -- hopefully, I'm answering your question.

COMMISSIONER DUFFLEY: You are.

MR. HOLEMAN: Okay.

COMMISSIONER DUFFLEY: And thank you for that answer. And then if you could turn to Page 38 of the report.

MR. HOLEMAN: I'm there.

COMMISSIONER DUFFLEY: On the second sentence of the first paragraph it says, "However, Duke Energy also stated there was no viable or practical mechanism in place to curtail the network customer load in the needed timeframe."

Could you explain this statement a bit further?

MR. HOLEMAN: In our current situation, we do not have the tactical ability to shed the load of our network customers.

COMMISSIONER DUFFLEY: And what do you mean tactical ability?

MR. HOLEMAN: For us to be able to select a breaker in their area of responsibility and open it up to reduce load. We don't have the information to do that. They do. But we don't.

COMMISSIONER DUFFLEY: Okay. Thank you. And in this communication protocols that you're instituting, is that something that you will be discussing with the network customers?

MR. HOLEMAN: We will be discussing it with them, but I think our general message will be if we get to that point -- where we're at that point -- we're in EEA-3 -- energy emergency alert three -- we are preparing to shed load, it is our next step. They will be walking that -- that path with us. And they will know how much we're going to shed, and that they would identify their proportional amount, and we'd do it together.

COMMISSIONER DUFFLEY: Okay. Thank you. So moving to Mr. Peeler. You stated today -- and I'll direct you to Page 20 of the South Carolina report. However, you stated today that you've been -- that the Company benchmarked with other Companies. I was struck by -- on Page 20 of the South Carolina report -- the percentage of the forecasting error. But I heard today that when you benchmarked, that you were in the middle with respect to the forecasting error -- errors; is that correct?

MR. PEELER: Yes. So just, I guess, to maybe talk to the chart that's on here. The forecast error -- the forecast error we benchmarked was predominantly day-ahead. And some of this is week-ahead. And so we know that if you go a week ahead in this cold weather, man, they are big numbers.

The day-ahead numbers that -- that we benchmark, which is, you know, when you have time to plan. Our forecast error was in the six to ten percent range. And we saw anywhere from five to twelve when we benchmarked with others. So pretty -- pretty much in alignment.

COMMISSIONER DUFFLEY: Okay. Thank you for that. And then could you talk a bit more about the one -- I'm on Page 7 of your -- today's presentation. You talked about how when you were benchmarking there -- there was a utility that was using the bottom-up forecasting, which you've added as well. When you reviewed that bottom-up forecasting, was that utilities forecast more accurate than the -- than the others?

MR. PEELER: So it was -- it was a little bit lower, but close -- closer to ours. It wasn't one of the higher ones. And to be, I guess, to be clear, they don't have a full implementation of bottoms-up forecasting. They have a tool and a vendor where they're incorporating some bottom-up forecasting. And in the areas where they had it, they saw some benefit. So they saw closer to five percent in the areas where they were using that.

COMMISSIONER DUFFLEY: Okay. Thank you for that. So moving to the unit preparation and generation. So it could be Mr. Gillespie. I have some Staff questions as well. And I'd like to talk about the -- the report with respect to the specific outages, and you mentioned that that Staff did the pre-walk-through to look for lack of insulation and look at your heat tracing.

And could you just speak a little bit more as to how you're going to try to catch every single issue? Because the 1000, as I understand it, with just three units, 1000 megawatts dropped. And could you just walk through again how the Company is going to try to catch every single one of these potential defects in -- in the installation of heat trace and -- and cracks within the insulation?

MR. GILLESPIE: Sure. So for the existing heat trace in the existing installation, we're going to start off first by installation quality. So we'll go into our work management systems and make sure that when we're doing work on insulated lines -- when we're doing work that involves lines with heat trace, we get that -- we get those -- we get those repairs done. And when we walk away from the repair, the installation and the heat trace is fully functional. That's the first thing.

We've also installed -- we're

installing temporary monitoring in some of the critical instrumentation boxes that will monitor the temperature and monitor the performance of the heat trace. So we would know that a heat trace circuit is not functioning as expected. That would be the second way that we're -- that we're going to do that.

And then the third way would be through training. We're going to train our operators to do a better job. To be better able to recognize the -- any -- any anomalies that they would see as they were walking down the plant that would impact insulation. The key is to be able to focus the operator on those critical pieces of -- of instrumentations. Those critical lines that are necessary.

Because you walk in the power plant and you just see a maze of piping, you know. Most of that piping is -- is going to be fine because it's got hot fluids going through it. We need to make sure that we have -- we have specified the particular pieces that we're going -- that we're going to look at.

We've also -- in addition to the heat

trace monitoring, there's other things that we can do to make sure that the heat trace is fully functional, and go out and test to make sure that the heat trace configuration is exactly as we expect it to be. Many of the issues we saw were on items of original construction.

COMMISSIONER DUFFLEY: Okay.

MR. GILLESPIE: And so -- it's no excuse. We should have configuration control down pat when we accept turnover from the facility. But there were some lessons learned in making sure that, you know, once a -- once a new facility is constructed, that as the facility gets turned over to my team, that those configuration control practices are rock solid.

COMMISSIONER DUFFLEY: Okay. Thank you for that. And then on Page 32 of the South Carolina report, you had a temporary fix for an outdoor piece of equipment. Has this piece of equipment received a permanent weatherization so --

MR. GILLESPIE: It's in progress. This is some of the work that we're doing at all the sites -- finishing up. This was an insulation piece of work. It should be done by now. We've got the -- we've got a -- I think it was an October -- some mid-October due date to go back and put checkmarks and get endorsements on all of these repairs.

And I apologize for how this repair looks. It was done in real time, and we just wanted to get the -- to get the -- the system back in service. But all the repairs -- so at the four facilities, all the heat trace repairs, all the installation repairs will be complete by cold weather. And most of the repairs are complete now. The only thing outstanding is where we were doing upgrades and putting those systems back together. So we will not go into the -- we will not go into the winter season with -- with open repair items.

COMMISSIONER DUFFLEY: And you've anticipated -- my next question is, do you have a specific date? I heard a mid-October date, but do you have, like, all of the repairs on these --

MR. GILLESPIE: We do. I just can't spit it out at you right now. And I could get it for you but -- or I can make one and just go tell the organization that we've done it. But just in fairness to Paul and his team, I'd ask that I maybe follow back around with you. No -- it's prior to -- it'll be prior to -- to the December 1 operational period.

COMMISSIONER DUFFLEY: Okay. Thank you.

MR. GILLESPIE: If that helps you.

COMMISSIONER DUFFLEY: Yes. That does help.

MR. GILLESPIE: I should have that date for you.

COMMISSIONER DUFFLEY: And you mentioned on Page 18 of your report today -- you talked about benchmarking with other Companies. And you mentioned, "We grabbed the good things as well." Could you just elaborate a little bit on what were the good things as well?

MR. GILLESPIE: You know -- training. How we train our operators. All of us train operators. But, you know, there may be something that we train our operator on that perhaps one of our neighboring utilities didn't.

And so we kind of -- we bundled up all

the good things out of training, out of monitoring, configuration control. So it's those things that when you talk around a table, and you say, you know, I do this, and then -- and it works for me, but then I find out that, you know, my counterpart in another facility is -- he's doing it too, but he's perhaps got something that's just a little bit better.

Those are the list of things that -- that we -- that we capture. The -- out of the three things that immediately out of the -- out of the meeting we had right after the event, we mentioned air dryers. So we were able -- we were able from that -- from that -- that work to go and improve our -- our ability to dry air coming up on our instrument air systems. This -- this idea about monitoring enclosures is another -- is another good one.

Water availability. Water availability and flow dividers for dual fuel operation gas turbine. I mean, it's a mouthful. But in the end, making sure that -- so dual fuel of oil -- we'll fire CT off oil or we'll fire it off of natural gas. Well, when you fire it off of oil, you get oil in all those lines to the fuel. If you just leave it there, it'll just -- it gums up the works. And when it's time to fire it off natural gas, it won't work. So you have -- we come back and we flush all the fuel lines with -- with water to get all the fuel -- fuel oil out so it trade for natural gas. We found out some -- some ways to go about that in a better way from the benchmarking.

And then a really big one -- a really big one is this notion of -- of how to combine cycle plants. How we can keep a combustion turbine. So combined cycle, combustion turbine, steam turbine. If we don't have the steam turbine available to us, how can we keep the combustion turbine in service without the steam turbine? By taking the steam that would ultimately -- ultimately be delivered to the turbine for power generation and just delivering that to the condenser -- straight to the condenser instead. So there's time limits, temperature limits, there's some operating procedures that we'll change. But we see a way that we can keep our combustion turbines in service if the steam turbine became unavailable to us.

So all of these -- you take all of these ideas. You go back, you get them through your engineering. You get them into your operational procedures. And what it results in is, in the end, improved reliability and more energy that we can give to Sam and his team.

COMMISSIONER DUFFLEY: Okay. Thank you. Then if we could move to Page 35 of the South Carolina report. You're talking about cause number three being the curtailed purchases. And in the second full paragraph, you indicate that Duke Energy made a series of power purchases scheduled for December 23rd and 24th on a day-ahead and intraday basis. I just want to make sure I understand when these power purchases were made by Duke. Were they made in the day-ahead market? Is -- am I reading that sentence correctly? Or when were the purchases made? I'll --

MR. PEELER: Yeah.

COMMISSIONER DUFFLEY: -- make it a --

MR. PEELER: They were made --

COMMISSIONER DUFFLEY: -- more broad question.

MR. PEELER: -- starting the afternoon before.

COMMISSIONER DUFFLEY: So the 22nd?

MR. PEELER: Yeah. And up into later in the evening so they were progressive.

COMMISSIONER DUFFLEY: Okay. Thank you. And with respect to the units -- I'm going to go back to Mr. Gillespie. I'm sorry. I'm jumping around a bit. How are you balancing the investments in units, like peaker units, that are nearing retirement, but also making sure that the units can perform when necessary? Could you speak a little bit to that balance?

MR. GILLESPIE: This is a great question. And we work this, I feel like, almost every day. We're asking ourselves about investment, lifetime of the unit, when the unit retires. Because as this event shows, when you get down to the -- when you get down to loads as big as what we had on Christmas Eve day, these units become very important.

So -- so what I would tell you is this.

That we work -- in terms of balancing, we work harder to repair equipment than we do to replace equipment. So a large capital investment in an asset that's going to retire in three years likely doesn't make sense when you do economic analysis and payback.

In some cases it will. So we balance -- we've done a -- we've done more about balancing, how we invest into repair and maintenance, the operating and maintenance expenses, as opposed to a complete change out of the system. So it would not make sense to go install a brand new widget, if I can repair the widget -- if the asset's going to be retired in the next year.

So there's -- we just -- we do an economic analysis. We determine payback. We operate -- we maintain the units such that they deliver. All our units that are in service now, we expect when -- when Sam calls and says I need whatever unit started up, we expect that unit to start up. We expect it to run, and we expect it to run for the duration that it's running.

When there is something that occurs on

a unit that perhaps derates its output, and we -- we step back, and we work with Sam and his team to find out -- well, the duration is this long. We got to do this much work. You see the load. Would you rather us operate? Or would you rather shut down now and fix it?

So we work with Sam. We work with Sam to determine the timing of repairs. So it's -- it's a -- it's a constant dance. Day in and day out, with -- and we balance -- we balance the needs of the grid, we balance the -- with the -- with the work that's required. And then -- but predominantly, the biggest thing -- the biggest and toughest decisions we make are between ONM expenses and capital expenses.

And ultimately, you know, we're just trying to -- we work to make sure that the value we deliver to the customer is maximized. And so that means that -- that generally means that we -- on these older units headed for retirement, get more repair activities than they do new widgets installed.

COMMISSIONER DUFFLEY: Okay. Thank you for that explanation. So I'm sure everyone on this side of the room listened to FERC's open meeting last Thursday. And I had a question about the -- one of the new standards. We discussed it the last time that the Companies were in front of this Commission in January. We talked about the current reliability standards -- the NERC reliability standards.

And I just was interested in some more explanation about EOP-012-1, which -- the last time the Company was before us, I think it had just been filed at FERC. And it's my understanding that standard FERC issued an Order to work on that standard a bit more. And so -- several questions. The first is, when do you expect an implementation date of that new standard?

And then the second question is, have -- have the Companies already actively started to meet those standards prior to its implementation? If you could speak to those two questions, please.

MR. GILLESPIE: This is the cold weather standard?

COMMISSIONER DUFFLEY: This is -- this

is the -- not the cold weather standard in response to winter -- Winter Storm Uri, but it's the additional standard the -- the newer standard. And it's called, I believe, EOP-012-1. When we discussed it in the prior briefing, it was entitled -- I think it was referred to as Project 2021.

MR. GILLESPIE: So I don't have in my notes -- this specific standard. I apologize. If this was the standard that came out on the cold weather -- the cold weather actions that were needed to be taken -- that was going into effect, that standard -- that standard was -- was written to have an effective date. We were -- you had to be in compliance, though, earlier than the effective date. And we were in compliance with that standard.

COMMISSIONER DUFFLEY: Okay. So I'm going to refer back to the previous briefing. I think Danny Damon spoke -- Bennett spoke to this. So there was the initial standard. It was EOP-011-2, which had an implementation date of, I believe, March of 2023. And the Company indicated that it was compliant with that standard in December of 2022.

But then there was a second additional standard. And that's the standard that I'm asking about. And so Mr. Bennett stated that this standard that was filed builds on EOP-011-2. So the standard that has been filed for approval requires you specifically understand the operational limits of your equipment. That you specifically identify your critical components.

And that there is two different requirements depending on whether you have a new generation station or an existing generation station. And that is the standard that I'm asking about.

Are you proactively implementing this new standard at this point?

MR. PEELER: Yeah. Let me try. So first of all, that standard is still in the process of being approved. We're familiar -- we have folks who are less -- or more familiar than we are, but who are in the details of that. And, in general, it fits with a lot of what Preston has described. It is -- but it gives you some more direction on how to do those things. It also has some reporting requirements.

But I don't think there's an implementation date set, and -- because it hasn't been approved -- but I think it would be best for us to follow up on your question with -- to make sure we get it right.

COMMISSIONER DUFFLEY: Okay. That -- I would request that you file something in the docket just stating how compliant you are. Understanding that there's no current implementation date within that --of that standard.

MR. PEELER: We can -- we can certainly do that.

COMMISSIONER DUFFLEY: Okay. Thank you for that. So now, I have a few Staff questions, and then I'll open it up to the other Commissioners. So, Ms. Bowman, with respect to the findings from this South Carolina report, do you -- do you generally agree with all of the findings that have been presented?

MR. GILLESPIE: I read the report.

COMMISSIONER DUFFLEY: Okay. Mr. Gillespie, you're welcome to answer the question.

MR. GILLESPIE: I feel like it belongs to me. So I've read it three times, in fact. And will probably read it three more before it's all said and done. When you read the report, I would say this. It's, I think -- factually, it's correct. The timelines are good. The information that's presented is good. You know, if -- if I delve in the report and started picking at it, it would come across as nitpicking. Probably defensive, and I won't do that.

Because, I think, factually, the report is -- is accurate. In a few cases -- in parts of the report, I think some context would -- would be helpful in the report. So, for instance, you know, this condition existed. What was its real impact to the -- to the ability to serve the customer? So you know, all in all, it's -- it's a report that is factual.

I would like some more context in some areas, but there's -- there's nothing about it that just kept me up at night. Many of their recommended actions were actions that we're -- we were already performing or planning on doing. So it's not like the recommendations weren't good. So when I read the report, I think that, by and large, it's -- it's a -- it's a quality report.

It was another view of -- of the situation that we faced, and we'll keep going through it -- make sure that, you know, if there's anything at all that we missed in our own evaluation that the report pulled out, we'll -- we'll grab it and implement that into operation.

COMMISSIONER DUFFLEY: Okay. Thank you.

MS. BOWMAN: And can I just add that I believe we have completed a lot more of the corrective actions identified in the report than the report mentions. So a lot more has already been completed.

MR. GILLESPIE: This is some of the context.

COMMISSIONER DUFFLEY: Okay. Thank you both for that answer. Now moving to Mr. Grant. I haven't asked -- have I asked you a question yet? I don't think so.

With respect to the rotational load shed tool, in reading the reports, it looked like, potentially -- just testing this tool in a simulated environment versus an operational environment was part of the problem. The Company didn't realize the issues because the testing was done in simulation. But I also understand that -- that -- that the Company did not want to incur customer outages to actually test it in a kind of real time operational setting.

Can you talk with us about the cost-benefit analysis currently? About testing this tool in real time so that everyone is assured that the tool, hopefully, will never need to be used again. But that if it is ever needed to be used again, that it will actually do what it's intended to do?

MR. GRANT: Yeah. So, again, we take load shed very seriously. And, quite honestly, to turn off load is a safety -- or a risk to the -- to our customers and to the public. So we would not bring that into the equation. That's why we have really spent a lot of time enhancing the environment that we test the tool under now.

COMMISSIONER DUFFLEY: Okay.

MR. GRANT: I spoke to some of those

things pretty much. You're right. The testing before lacked volume as well as the magnitude of megawatts that were tested. And that, in and of itself, allowed some of these issues to go under the radar and were not picked up on.

But we feel pretty confident now that we've enhanced that environment both from a duration -- amount of megawatts load shed, plus we've added all the interconnections -- I shouldn't say all -- a lot of the interconnections that the tool would have in play, if it was to actually run in production -- to make sure that we understand -- is there any other impacts to the tool from other applications that are being run at the same time.

For instance, if, you know -- if the tagging -- tagging tool is running, it's not negatively impacting the RLS tool. Or the RLS tool is not negatively impacting our outage management system. Those kind of things. We have that interconnectivity at play now. So I think we're definitely better postured to see if there's any issues if we did have to run it in a production environment.

COMMISSIONER DUFFLEY: Okay. Thank you for that. And then, how does the RLS tool take into account the cold load pickup?

MR. GRANT: Well, so as I mentioned before, we target customers to be out about 15 minutes in duration. That could go a little longer maybe up to 30 minutes, depending on how many megawatts you're wanting to shed. But we feel pretty comfortable that if you keep a customer out no more than 15 to 30 minutes, you wouldn't run into those cold load pickup issues.

When we had customers out two hours, three hours, now you definitely introduced that dynamic into the equation. Of course, that required us to go out and do sectionalizing, et cetera, to bring those customers back.

COMMISSIONER DUFFLEY: Okay. Thank you for that. And then, I'm not sure who this next question goes to. Could you speak more about the role of energy efficiency and demand-side management in future extreme cold weather situations like this? What -- what proactive metric or tool or procedure that -- has the Company created to squeeze more benefit from EE and DSM?

MR. HOLEMAN: I can address kind of the -- ensuring that we're utilizing -- maximizing our demand response capability. That's a part of the grid risk assessment team. Individuals who own those programs are on those calls. And we can -- we can, one, know what's available to us in that particular window of challenging operating space.

And then we can make sure that we're leveraging the maximum amount of demand response, DSM, that's available to us at that time. So those folks are involved in the grid risk assessment meetings, and they're also involved in the grid threat discussions as -- as events evolve to that level.

COMMISSIONER DUFFLEY: Okay. Thank you.

MS. SIMS: I can also add that we are working very diligently right now to enroll more customers in our programs, and to make sure that we're doing our very best to educate them on the benefits for them -- for our customers in general -- the benefits of energy efficiency and our demand response programs, but also for the grid itself.

COMMISSIONER DUFFLEY: Thank you for that additional information. In a presentation to the Georgia Public Service Commission, Southern Company testified that the Carolinas region is dependent on them to get power from regions like Florida and MISO. In the same hearing, they testified that it was a big purchase from Florida that saved them from having to curtail -- or load shed. So I guess the question is, do you agree with this assertion by Southern Company?

MR. PEELER: So I guess, just --

COMMISSIONER DUFFLEY: The -- the tendency --

MR. PEELER: -- just to clarify.

COMMISSIONER DUFFLEY: -- that --

MR. PEELER: The dependence on getting power from Florida to the Carolinas?

COMMISSIONER DUFFLEY: And MISO. Mm-hmm.

MR. PEELER: And MISO. In general, that would be true. However, rarely is there any power from Florida or MISO coming to the Carolinas.

COMMISSIONER DUFFLEY: Okay.

MR. PEELER: That's a -- that's a really -- that's a long putt. Right. So to -- to make that happen. That would not be a primary place we will be looking for -- for support.

COMMISSIONER DUFFLEY: Okay. Thank you for that.

MR. HOLEMAN: And just one more point on that. So in our discussions with Southern Company, our peers at Southern Company, they have long-standing relationships -- contractual relationships into Florida. And so that -- that is what helped them to avoid getting to that point of -- of having to load shed. So -- so they were taking all the available resources out of Florida because they had the contractual relationships. They're directly connected through Georgia Power. And so that -- there wasn't anything for us to get from Florida on that particular day.

COMMISSIONER DUFFLEY: Okay. Well, thank you for answering the questions. I'm going to open it up to other Commissioners. Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Just a couple of things. Mr. Jirak, the copy of the ORS report that we have is the public copy, which contains all the redactions and particularly some of those redactions that would be of interest. Is the Company -- are the Companies willing to provide this Commission with an unredacted copy filed, of course, with appropriate confidentiality designations for public purposes, so that the Commission can see the full -- full report?

MR. JIRAK: Yes, of course. We'd be glad to do that.

COMMISSIONER CLODFELTER: Thank you. Thanks very much. There was -- in the ORS report, there's a -- there's a reference to the fact that the Companies made a decision not to activate 40 megawatts of demand-side management capacity that could have been called upon, and I just want to hear discussion about the reasons for that.

The reference is that these were residential DSM programs, and that they were not activated. So I just -- can someone talk to me about the decision-making of why that was not called on? I think the -- I think the ORS report -- I'm sorry. I don't have the page reference in front of me. It says that the Companies made a decision not to call upon that on the 24th but hold it in reserve for a later date. Is that accurate? Is that your -- I see a lot of puzzled looks there.

MR. JIRAK: Give us one minute. See if we can put our --

COMMISSIONER CLODFELTER: Sure.

MR. JIRAK: -- fingers on the right page.

COMMISSIONER CLODFELTER: My apologies. I made a note of it, but I don't have the actual report in front of me.

MR. JOSEY: I believe the reference is on Page 55 of the report.

COMMISSIONER DUFFLEY: Thank you, Mr. Josey. Page 55.

MR. GILLESPIE: On page 55 I see customer communication. So I must have a different --

MR. JOSEY: I'm looking at the PDF.

COMMISSIONER CLODFELTER: Actually, it's on Page 44.

MR. JOSEY: 44. Sorry about that.

COMMISSIONER CLODFELTER: Under Section 4.3. Carries over to Page 45. On December 24th, Duke Energy chose not to utilize certain load reduction programs with total capacities of 40 megawatts.

MR. PEELER: We can follow back up. I think -- there's a comment in here, I think, that's part of it, is that it was a -- one of the programs was a commercial program, and it was a holiday. So not an expectation to get anything out of it because the businesses were closed. But we can follow up with more detail.

COMMISSIONER CLODFELTER: It's not like it would have changed the events of the day. That 40 megawatts would not have -- I really am just curious about the decision-making rationale. That's all.

MR. HOLEMAN: We were -- we were looking to execute anything that would have an effect that morning. But we'll follow up. Yes, sir.

COMMISSIONER CLODFELTER: Thank you. Mr. Gillespie, there's also -- again, I made notes, but I didn't bring the report actually with me. I brought my notes. The -- there's a reference in the ORS report to a couple of remote CT starting problems. Can you just sort of say a little bit more about what happened there, and what corrective actions the Company has taken to avoid that problem in the future?

MR. GILLESPIE: So I think the report specifically mentioned a few of our older CTs had -- had fluid.

COMMISSIONER CLODFELTER: Right.

MR. GILLESPIE: I think there were four of them. We got -- we got two of them started quickly. One, we trouble-shot, and the other one, we ended up having to do some repairs on. Determined -- determined there was a bad card -- bad controls on that. But these are -- these are reports -- these are -- these are machines that don't run very often.

COMMISSIONER CLODFELTER: So these were not weather-related issues. They were just --

MR. GILLESPIE: They were not weather related. They were -- I think they had not been run perhaps since -- since that summer. Which is a lesson learned for us, you know --

COMMISSIONER CLODFELTER: Again, to your point -- in your dialogue earlier with Commissioner Duffley about your decision-making about when to replace and when to repair.

MR. GILLESPIE: So these are oil fired CTs. They sit down near the hydro-plant just -- just off the Pee Dee River as you're coming in. As you're going over --

COMMISSIONER CLODFELTER: That's why it's -- the question is since they were oil fired, I didn't know whether the cold weather event had any causal connection to your difficulty starting those units.

MR. GILLESPIE: Not really. I think --

COMMISSIONER CLODFELTER: Okay.

MR. GILLESPIE: We had some cold weather. You know. We had -- we had a CT at Mill Creek that didn't immediately fire up on oil. We transferred it to natural gas. Got it up and running in 30 to 40 minutes. We had -- we had these units. I think it was two, but anyway, we had some of these units running quickly. Within a matter of hours.

There was one that we ended up having to do some more repairs on. And so what we're doing about that is in the future, we'll -- we'll -- we'll pick where we stage some of our technicians to be there on site at these remote units. Have them pay more attention to the ones that don't run quite as often. And, again, we'll look at the frequency of starts.

COMMISSIONER CLODFELTER: Thank you. That's all I have.

COMMISSIONER DUFFLEY: Commissioner McKissick?

COMMISSIONER MCKISSICK: Just a couple of questions. Not many. So I think Commissioner Duffley did an excellent job of covering the landscape. I gather that in the past, you had not experienced this type of extreme weather in December. And your regression analysis and forecasting tools did not project that you would need to have the capacity that was actually needed during this Winter Storm Elliott.

And I gather some of the -- some of the systems you had out there were down due to just routine maintenance that was being performed. Now, in light of the fact that you now have that history of this type of weather event, moving into the month of December, do you reasonably anticipate that whatever normal maintenance that might be required that would cause you to not have available certain capacity that you would continue with that practice?

Or would you, in the future, try to get that work done before December rolls around? I mean, it's just a basic question as to what your practices will be moving forward in light of this history that you've observed and experienced.

MR. GILLESPIE: That's right. So, you know, we talked about outage optimization. And a key piece to that would be to get in and out of our outages by December. This year we, you know -- we worked on that. We scheduled our outages such that they are -- they'll be complete by the first week in December. Its -- I go back to these shoulder months.

So if you look at when, like, our hydro

units can do their outages. Well, they get -- there's -- there's all different types of competing effects as when you schedule. They can or can't be out during the summer. What the water flows have to be in order to allow the units to be out of service and the like. And so we take all of that into account.

But for -- but -- but in the end, we're optimizing our outages to minimize any outages in December. And certainly our big thermal generating sites to be out of outages prior to the -- prior to the December month. Another interesting thing we're doing too is just like the, you know, where you sequence your outage and when we -- we're informing outage start dates by the risk of some of the work activities that we're doing.

So if you're doing inspections, say at nuclear, and if you find the condition you're expected for, and it's going to push your outage out further into the cold weather months. And we should inform our start date by that information. So we're really -- we're adding a level of sophistication to our outage scheduling process to ensure that, you know, we maximize the energy available to Sam and his team to deliver to the customer.

COMMISSIONER MCKISSICK: Okay. And -- and I guess another question that came to my mind in reading this South Carolina report, it looks like you have this internal meteorological team that was out there really doing his job. And suggesting, you know, apparently, as early as December 12, what you might expect.

And certainly by December 21st, you know, making projections about what that temperature range was going to be, you know, 15 to 20 degrees colder than what would have been typically forecasted and -- and then actually going there and saying windchill factor will be five -- negative five degrees up to a positive five degrees. They were factoring in the windshield.

I mean, it seems like they had insights that clearly suggested that you were not going to have enough generating capacity available to meet the demands that were forthcoming. Now, that was my read of what was in that report. So -- yeah.

MR. PEELER: Yeah. I'll respond, sure. So two -- two things, there's forecasting weather, and then there's translating weather into load.

COMMISSIONER MCKISSICK: Yes.

MR. PEELER: And so the -- the challenge here was the weather forecast was fairly close, particularly as we got closer to the day. It was fairly close. The challenge was translating that weather into the customer behavior and the load performance. That's where our model struggled.

The meteorologists did a pretty good job of getting the weather right, but translating it into the actual load that we would anticipate is where this -- the regression model and all things we've been talking about, didn't perform like -- like it needed to. That's the -- that's the gap, which is -- we're taking on -- you know, we spoke about a number of actions we're taking to try to close that gap.

MR. GILLESPIE: And if I could add?

COMMISSIONER MCKISSICK: Sure.

MR. GILLESPIE: We were taking action

based on -- on the weather and how it translated into load. We brought six of our units into service between the 12th and toward the 18th as a result of the changing forecasts. So we were looking at -- at what energy was available out on the market as a result of these changing forecasts.

So we're proud of the weather -- the weather team. They give us good information. They were giving us good information. We were -- we were actively working that information.

COMMISSIONER MCKISSICK: So back during Winter Storm Elliott when you were getting that good information, I mean, was there any degree of effort to reevaluate in that ongoing period? I mean, having seen what was forthcoming and trying to, you know, reevaluate, in a real time basis, what you needed to do to take those factors into consideration.

And looking at what that increased demand would work into in terms of customer behavior. I mean, I'm just wondering, in that real-time period. I mean, understanding those efforts that seem to have been taken to mitigate things.

MR. PEELER: Yeah. So the -- the forecast was -- was updated multiple times per day, throughout the week, as we, you know, begin getting, you know -- fine-tuning in on the weather itself. And we planned to that forecast. And so actions were taken all week long, even the night before, to either bring additional units online, or make purchases to make sure we had adequate reserve margin.

And then for a number of the reasons we've talked about, that did not work out. Right? Either purchases didn't show up, or we had some generation challenges, and the forecast was different. But, absolutely, all the way through, I think you can see steps taken to plan for what we believed was the forecast.

And, again, it was -- it was not completely accurate. But the forecasts were updated multiple times per day to take that into account.

COMMISSIONER MCKISSICK: It seemed like the South Carolina report suggested that you didn't do much between the 23rd and the 24th to go back and reevaluate what --

MR. PEELER: Those are some of the nuances that we don't completely agree with in the report of their characterization of not updating forecasts. The forecasts were updated.

COMMISSIONER MCKISSICK: So you would take issue with that characterization in the report?

MR. PEELER: We would.

COMMISSIONER MCKISSICK: And, of course, you went out and made purchases. And I want to really understand. When there is a firm commitment. When you know that it's going to be delivered rather than curtailed. Because I used to, prior to this incident involving Winter Storm Elliott, think that the word firm and firm -- not firm with an asterisk that stated, you know, "If available, we will deliver, and it may be that when you need it the most, we will deliver nothing."

Because that's what happened.

MR. PEELER: Yeah. So -- so my experience, that's the first time I'm aware of -- we had a firm purchase curtailed.

COMMISSIONER MCKISSICK: This is the first time.

MR. PEELER: Yeah. So we thought firm meant firm as well. And, certainly, I understand, and I'm sure you've seen, PJM's reports and so forth on their situation. The amount of generation loss so -- but again, firm to us was firm. We were anticipating that being delivered like it has been many times.

COMMISSIONER MCKISSICK: Historically.

MR. PEELER: Yeah.

COMMISSIONER MCKISSICK: Moving forward. In light of that, I mean, are you reevaluating, you know, what to do in terms of firm commitments? I mean --

MR. PEELER: Yes. I think that you're going to a really great point. So, one, we certainly evaluate, you know, the -- where the -- where the energy is coming from. In this particular case, there really wasn't another option. There wasn't, you know -- you talked about Southern Company's situation. So we didn't have a lot of option. But we're -- we're certainly evaluating, you know, how much we can depend on outside purchases to serve our peak loads.

And, you know, not to bring it up here, but certainly we'll be talking about that in the CPRP discussions that are coming soon. But we're -- risk evaluating is the risk of -- of the imports during peak times. What -- what can we rely on? And what do we need to be able to generate ourselves so that our customers are -- you know, have -- have an adequate supply? So, absolutely.

COMMISSIONER MCKISSICK: And I am glad to hear that's the way you're approaching it because I would -- with that experience, and knowing that extreme weather events are probably more likely moving forward, that, you know -- that to deliver a degree of certainty or to -- to have actual reserves that are your spinning reserves, would likely be a better --

MR. PEELER: Yeah. We certainly have to evaluate that with the way, you know, the resource mixes are changing for everybody, the types of resources that are available. So we're definitely considering that.

MR. HOLEMAN: Commissioner McKissick.

COMMISSIONER MCKISSICK: Sure.

MR. HOLEMAN: I'd like to add something. So in my 38 years in the industry, firm purchases have served a lot of purposes, and they've been highly dependable, as Mr. Peeler's referenced, but it's always been the understanding that the seller's customers are more important than the buyer's customers.

If they're at the place of where they're fixing to shed firm load, they will cut you. That's the nature of the market. And PJM was on the verge of shedding their own customers, and so they could have gone two ways. They could have gone to transmission loading relief process and cut the schedule, or they could have cut the schedule based on the inadequacy of their generation. But that is the nature of depending on firm purchases.

COMMISSIONER MCKISSICK: Got it.

MR. GILLESPIE: This is partly what is motivating us in terms of our reserves margin, and the need for additional reserve margins. Because when you look at what can you count on the markets deliver -- to deliver, when can you count on the market to deliver. And when you -- when you put all that in the mix, it clearly points to the need for increased reserve margins.

COMMISSIONER MCKISSICK: And based upon the South Carolina report, it seems like I also recall where Duke Energy was still actually serve -- selling power to other entities as early as, I guess, around the 23rd or so; is that correct?

MR. PEELER: It is. So when we had available energy, we were providing energy to TVA. Again, while we had -- it was available -- to prevent them from shedding more load. They would have, you know, again, that would be a -- utilities would do that. They would do the same thing if they --

COMMISSIONER MCKISSICK: Right.

MR. PEELER: -- had the available energy. And then, you know -- also we had some sales to South Carolina Utilities over this event as well.

COMMISSIONER MCKISSICK: Okay.

MR. PEELER: That did not --

COMMISSIONER MCKISSICK: It didn't impact it because --

MR. PEELER: That was when --

COMMISSIONER MCKISSICK: -- was being sold.

MR. PEELER: We were not in a situation where we were shedding a load at those points in time.

COMMISSIONER MCKISSICK: It was just before that event, I gather.

MR. PEELER: And after.

COMMISSIONER MCKISSICK: And after. Right. And in terms of this rotational load share tool, I gather there were problems because of software updates that had occurred. Do you know when those software updates had occurred as it related to this particular storm event? How -- how far in advance had they occurred?

MR. GRANT: Now, the actual software patches that we installed were known issues known to the vendor. Unbeknownst to us, those software patches existed or that that issue existed. So, of course, once we engaged with -- with our RLS vendor, they did let us know those patches existed, and we then installed them.

But that's why we have since -- we got a very proactive approach with that vendor. We're having weekly meetings with that vendor to make sure we're aware of anything that's popping up from an industry perspective around RLS tool. And, again, any software patches that would be applicable to the versions of RLS that we're running as well.

COMMISSIONER MCKISSICK: And in terms of interoperability -- in terms of your ability to use -- once those software patches occur, I take it it interfered with your ability to actually use the tool effectively. Is that a correct assessment? Or is that an incorrect statement?

MR. GRANT: I mean, again, the latency issue, as well as the issue with the tagging function -- again, both of those were known. They were known to our vendor, they were not -- they were not known to us at the time.

COMMISSIONER MCKISSICK: And I know, in response to Commissioner Duffley's question, she asked about this rotational load share tool and, you know, how you went about testing it, things of that sort. And I know your response is you don't really want to do it in real time to negatively impact customers.

But do you think that if customers were aware that they might be subject to a potential test, that it might be worthy of periodically, in real time, conducting a test and just providing notifications in advance that we want to be prepared in the future. So this particular day, a weekend, or whatever it may be, we intend to try to test it so we can make sure everything is working and will work effectively in the future.

And, you know, in using the notification systems that you have as well as other tools to forewarn people so that they can perhaps even feel a sense of confidence even though they might be inconvenienced.

MR. GRANT: We have not considered actually running the system in production to basically test it. That's why we've enhanced that testing environment to include about anything we can think of, as far as interconnection, the data that's being transferred, etc.

So I think we feel like that we've vetted out the issue with the tool and addressed both the volume issues, as well as the duration issues that we weren't testing earlier on. That allowed some of these things to go under the radar screen and not be -- not be detected. So, you know, I don't think -- well, one thing that did come out of the 24th event -- we did prove that the load shed tool would trip breakers, and it would restore breakers. So we know that's taking place as well.

It's something we can consider. But I think we feel pretty comfortable with the environment that we've set up for going forward. And also the regular meetings with the vendor should keep us on top of any software patches or any industry issues that come up.

COMMISSIONER MCKISSICK: And I'm just curious. Do you know of any other utilities elsewhere that might have actually tried it? I mean -- and I have confidence that, you know, what you have -- measures you have taken proactively will, hopefully, resolve the potential issues or problems that could occur in the future. But I'm just curious if anybody actually had done it in real time?

MR. GRANT: I'm not aware of anyone that's actually ran their RLS tool in order to prove it out from a testing perspective in production.

COMMISSIONER MCKISSICK: I got you. And then lastly, I know right now you say that there's like 90 percent of the customers you have either e-mail addresses for or ability to text message them or -- or to communicate with them. What percentage would it have been at the time Winter Storm Elliott occurred?

MS. SIMS: We went back and looked and we believe it was between 60 to 75 percent, depending on the state and the area. But in North Carolina, we have quite a few mobile numbers for our customers, at least over 60 percent, and even more e-mail addresses.

COMMISSIONER MCKISSICK: And what measures were taken to actually get it from 70 to 90, because I commend you on doing that. Because, I mean, that's -- that will help a lot if these events have to take place in the future.

MS. SIMS: Great question. So what we did was a series of measures. So we went through and auto-enrolled customers that had started service since the beginning of this year, which is something that we typically do on an annual basis. We just hadn't done it yet. This was the end of the year. We had done -- needed to start and do some of that this year.

So we needed to refresh it. So we refreshed those. But secondarily, what we did is that in the past we've had a feature within our outage alerts that customers, while they're experiencing an outage, if they're getting updates quickly, they can -- they can type "stop," and they'll stop getting outage alerts.

Well, that was unenrolling customers in the program. So then they were no longer enrolled. And we didn't have a process at that point to go back and reenroll them. So they had to take a step to do that. Since then, we have gone back and added a pause feature to outage alerts. So that customers can now type pause instead of stop.

And we've gone back and done an active campaign to reenroll those customers who, in the past ever since we've launched outage alerts, have typed "stop." So that was really what got us back to the 90 percent.

COMMISSIONER MCKISSICK: Well, that's good to know, and I commend you for taking those efforts. Because I think communication is critical if you're facing this type of potential down shedding event. And, unfortunately, I don't think communication was optimal. And, obviously, this was an unprecedented event. I hope that the lessons that you learned, that we all learned, have been an excellent tool to serve as kind of a roadmap for what can be done better.

And I feel pretty good with what I've seen here. I know the Public Staff continues to have some concerns, and I went through some of their data requests. And I guess they will speak to some of those issues at the appropriate time. But I'm cautiously optimistic that we're a lot further along in terms of mitigating the need for a down -- a downloading -- down shedding event -- load shedding event, I should say, in the event we were facing similar circumstances of extreme weather in the future.

COMMISSIONER DUFFLEY: So I have a follow up question with respect to PJM imports. And I think I remember when you came in January, you had talked about you're going to reassess, I think it was 2000 megawatts maybe of those imports. But it reminded me of a question that in PJM's report they stated, "If PJM had not provided this assistance, it is likely that Duke Carolinas and Duke Energy Progress would also have had to engage in more load shedding."

So could you please speak to that? And do you agree with that statement?

MR. PEELER: Yeah. So, like, the -- the energy that we had purchased out of PJM -- we had firm and nonfirm purchases. They were cut across our peak. All of them. Which is when we were short. So I don't agree with that statement. We did get energy prior to the peak and after the peak. But again, that's not when we were short. So I don't -- I don't know the specific reference in the report. But we didn't -- we did not really benefit significantly from the -- from them during this event.

We were -- We were surprised by the very short nature of the -- the cutting of those schedules.

COMMISSIONER DUFFLEY: Okay. Thank you. I did want you to speak to that statement. Thank you very much for that. And -- and Mr. Holeman, I appreciate your response to Commissioner McKissick. And I understand the difference between a firm purchase and network customer. But it seems like if -- if the scenario is, you take care of your own customers first, should seem to work with network customers as well. And that's -- that was the purpose of my questioning earlier to you today is looking at that concept in transmission service as well.

MR. HOLEMAN: And we are working on that relationship, and how we would handle that in the future.

COMMISSIONER DUFFLEY: Thank you. So with that, Commissioner Hughes, you had a question?

COMMISSIONER HUGHES: Yes. I know a lot of what we've been discussing this morning, and the focus of the investigation has been on equipment and software and communication. And you've talked a lot about all the impressive measures that you're -- you're doing to address those.

I'm just curious. In our situation, and I know we're structured completely different than -- than some of the other states where we've been reading about how they cope with similar situations, but given -- given in our situation, I haven't heard anything really about economic tools, which are the principal tool in some of the other states. Granted, they're -- they're set up much differently.

Has this experience kind of made anyone think about how the economic tools we do have, which, when I say economic tools, pricing, penalties, that sort of thing. Just curious, has there been any discussion about those? I mean, particularly following up on some of the questions we've had about, like, when firm gets curtailed?

You know, I don't know if we had -- if PJM has a penalty that they have to pay. But for your relationship with some of your wholesale customers -- and I know in this particular incident it's very specific and it might not work. I'm just curious where economic tools kind of fit into the general discussion moving forward?

MR. HOLEMAN: I think in terms of the tariff, there is a mechanism within the tariffs. It's energy and balance, and it's kind of done over a monthly period. If a particular network customer is long or short, they pay -- they're compensated at a less than incremental cost or they pay higher than an incremental cost there is -- there is an economic driver there.

My observation is that that works well in more steady state scenarios. It doesn't work as well in these emergent type of events like we experienced on the 24th.

COMMISSIONER HUGHES: So that -- Okay. That's -- that's the extent.

MR. PEELER: Well, I mean, all of our demand-side programs are economic. Right. They're incentive in some manner. They incent customers in some manner to participate. I guess the discussion can be are they -- there are not penalties, they're -- there are incentives for participation.

So that's something, you know, we're certainly looking for ways to expand. Right. But we have -- I'm not aware of if we want the penalties for the majority of those programs. But as Sam mentioned, there is a penalty for the network customers. But it's -- it's probably meaningful in normal operations. Not so much in an extreme event.

COMMISSIONER HUGHES: Okay. Well, turning around on the incentives for -- even for the DSM programs. I mean, any research that shows that tweaking the incentives could create a lot more participation? I mean, is the -- is the level of incentive something that is being looked at?

MS. SIMS: Yes. Absolutely. So there are a number of pilots right now that we're running across our areas with different types of customers to see not just behavioral demand response, to see what types of messaging could work. But also, what could those incentives look like. We could follow up with a more -- with more specific details around those programs, though.

COMMISSIONER HUGHES: Okay. That's all. Thank you.

(Speaker overlap.)

MR. HOLEMAN: So a lot of the -- lot of the programs that I've read about, like, in California, for example, they -- I think there's some evidence that it worked when they appealed for some customer reduction during a high demand period. But the problem is, there's no certainty.

COMMISSIONER DUFFLEY: Right.

MR. HOLEMAN: And there's no -- there's no analytics that tell you how much you're going to get. You're making a plea for help. If it works, great. But it's -- Taryn would know more about it than I do, but the certainty of what you're asking for is not there. And are you going to get it the next time you ask if you have two straight days of that kind of situation?

And I think that's where -- that's where we've got to get in terms of clarity of what we're asking for, and what we're going to get. Because if you don't, it just adds to the uncertainty. And when you add uncertainty in a real time situation, you got to add margin to deal with the uncertainty. So there is a certain degree of a balancing act as we -- as we move forward in that space.

COMMISSIONER DUFFLEY: Commissioner Kemerait?

COMMISSIONER KEMERAIT: Following up about -- with the DSM discussion. Can you elaborate a little bit more on how the improvements that have been made so that DSM can be called upon or used to the maximum extent possible during holidays and weekends? Because I think that was a problem during Winter Storm Elliott.

MR. HOLEMAN: So what we're doing is -- there are -- DSM owners within the Company have always been a part of what was historically called the tailgate process. But now we formalized that with this grid risk assessment process. They're involved.

And so when -- when we get to the point

where, in a grid threat, we will know exactly how much DSN exactly -- it's probably -- we will know how much DSM is available to us during that period of time. Is it a holiday? Is it a weekend? That kind of thing. We'd have -- we will have more certainty as to -- as to the effect of DSM as we execute it.

So that's -- that's a part of what Mr. Peeler talked about. The formalization of this process. We get all the right people in -- in the room. We make sure we're not leaving something out. And then we develop the plan in a grid threat scenario to execute that in a timely manner, which would include the timing of the need.

COMMISSIONER KEMERAIT: Okay.

MR. HOLEMAN: Taryn, is that fair?

MS. SIMS: Absolutely.

COMMISSIONER KEMERAIT: And then, I think this is for Mr. Gillespie. So the -- my -- I've got a couple of questions about this. But what I'm trying to better understand is improvements to processes for being able to get generation resources that are not online.

Getting them available during emergency situations like Winter Storm Elliott.

So I'm going to -- the -- I'm going to be asking about the planned outages that you've talked about, and then also about the generation units that are in the extended planning reserve. And so -- so I'll start with the -- the planned outages.

And I think that you -- you testified that the outage schedule had been -- had been improved or updated. So that the thermal generation would be concluded by the -- the first week of December. What was the outage schedule for thermal generation last year in 2022?

MR. GILLESPIE: Well, we had -- we had one of our nuclear units that was out of service. We had -- I think it was four of our coal units out of service, but two were in EPR. Two were down for forced outages and not in planned outages. So we're due down -- we were out service due to equipment repair.

And then we had one combined cycle that was out of service. It was a maintenance outage. A forced outage for equipment repair, as well.

So, you know, out of all of that, we had small amounts of hydro. If you look at the hydro, we had -- I summed it up. It was some -- maybe 5 or 600 megawatts of hydro out. I can get that number.

But the predominant -- predominantly, it was made up of one bad creek unit. 340 megawatts that was out of service. These are long duration -- planned out just to upgrade and upgrade the units. And had that outage been finished, we would have taken unit four out of service and moved right into -- into that upgrade.

So -- so for the large thermal generating units -- Robinson -- Robinson's outage had extended. That was the planned outage. The rest of the thermal generating sites were in maintenance outages, with the exception of the EPR units Allen 1 and 5.

COMMISSIONER KEMERAIT: So for the Robinson nuclear outage, was the -- did you have an outage schedule in place in 2022? Where the intent was to have all planned outages completed by the first week of December. Was that --

MR. GILLESPIE: The first week in December is something that we have done since December of 2022.

COMMISSIONER KEMERAIT: Okay.

MR. GILLESPIE: So that was an outcome of some of the work that -- that we were doing was to -- to really squeeze in the shoulder months.

COMMISSIONER KEMERAIT: And then for the -- for the planned outages, my understanding is is that it is either impossible or very difficult to terminate planned outages so that generation can be brought online during emergency situations. At least that was my understanding at the time of Winter Storm Elliott.

Are there any changes or improvements to that? Where a planned outage could be? Is there a change or an ability to terminate planned outages so that generation can -- can assist during emergency events like Winter Storm Elliott?

MR. GILLESPIE: Yes. A very fair question. So -- well, first of all, it's possible to terminate a planned outage. So it is possible. It is difficult, but we do difficult things all the time. So what you would have to do with a planned outage? The answer -- so the answer then becomes -- to your question becomes: It depends.

So it depends on the nature of the outage. So if the planned outage was a generator rewind, you're not going to turn that around on, you know, when Sam says, "Preston, I need energy." You're not going to be able just to stop that, because it's such a long duration activity.

If the planned outage is -- if there's a certain set of conditions such that the main -- the main -- the critical path of the -- say the purpose of the outage is coming to completion. We have opportunities then to perhaps -- to bring those forward.

Or if we had an outage that we were coordinating resources between units, and the like, we would have the ability to maneuver our resources to get a unit -- the unit in service the fastest. Put the most resources on that. So we have a -- we have tools at our disposal to allow us to do that. So the answer your question is, it is possible to turn a planned outage around and do it early. How quick you could react to that would depend on the nature of the work that's being performed.

COMMISSIONER KEMERAIT: And is that something that -- that Duke is going to be looking into and taking into account in any next emergency situation so that you can have a generation online if possible?

MR. GILLESPIE: So the answer to your question is yes, and we do that now. So if -- if we have an outage -- if we have an outage in flight -- let's say I had an outage in flight, and it's the middle, you know -- it's some weather event or some other event happens, another unit goes out of service that begins to impact our ability to serve the customer.

We would immediately begin looking at the work that's in flight with the other outages and -- and see how we could wrap those up earlier. We would also look if we had an outage that was scheduled to be coming out of service in that amount of time. Looking -- how we could defer and keep that unit in service as well.

So -- so we do -- we do look at that and -- and would exercise the option when it's available to us.

COMMISSIONER KEMERAIT: And then, similar questions for the units. It would be an extended planning reserve and the -- what I read in the South Carolina report is that Allen units had about 426 megawatts that were not available during the load shed event, because they were in EPR.

And the -- my understanding is is that the -- the time or the process for bringing, for example, the Allen units back online, so that the generation would be available was approximately five days in December of 2022.

Has there been any improvements in the -- the time that it would take to bring a thermal unit that is offline for EPR during an emergency event? Can it be done now more quickly than, say, five days?

MR. GILLESPIE: Yeah. So the five -- what the five days is -- is the five days is a notification window that -- that's provided to --

say in five days, we will need the unit. And then that allows -- that would allow our -- our operating teams to -- to mobilize and do the things needed to start the unit up.

Physically, we could start a unit up in less than five days. What happens with -- with Allen -- and Allen's out of the EPR. When units go into EPR, Allen's a bit of a unique case because its capacity factor is so low, it's down in the single digits, that it's got a small contingent of resources. And it also relies on resources from another unit.

Early on when it was projected that Allen would not be needed, some of the resources at the site -- they -- basically, they traveled. It was Christmas, and they had traveled. So we had to work to get resources back. By the time -- by the time -- as the weather changed, the forecast change, and the need changed.

We were faced with a decision between Allen and Marshall. What was the units that we could get back the soonest? Which -- which of those units. We were doing a repair on -- we were doing a repair to a pump on a Marshall unit, and we were doing a repair to tubes -- a tube leak repair on a Marshall unit.

And what we decided at the time was that it would be quicker to get the Marshall units back in service and get that energy back available to -- to Sam's team, than it would be to pull those resources off and send them to Allen.

There were some other issues that emerged during the Marshall startup that would say, well, that decision may not have been completely correct. We'll never know -- I may have had an issue starting up Allen. But, you know, if we'd had it to go over again -- if I had a crystal ball, I'd say I'll lock everybody down in place. And say, you know, you can't leave. You can't -- you can't go. We'll have those resources available.

So there's -- there's lessons learned. But there were things happening in real time as we were adjusting between the units out of service to get the -- to get the most energy back in service the fastest. And -- and in this case with Allen -- the Allen units not being available, we -- we probably could have gotten Allen back had we sent the folks from Marshall.

But it would have delayed the Marshall return to service. It would have just been a race as to which one would be right. But we made the best decision with the information we had at the time.

COMMISSIONER KEMERAIT: Okay. And then last question. I think this is for Mr. Peeler. This is about the -- the updated models or forecasting method. And -- and you talked about investigating the bottom-up, short-term load forecasting methods. Was the bottom-up -- excuse me -- bottom-up forecasting method, was that utilized with less granularity than is being proposed now during Winter Storm Elliott? Or is this an entirely new forecast?

MR. PEELER: Yeah. We currently aren't doing a bottom-up forecast. We're currently doing a top-down but, you know, historical -- historical loads, historical temperatures with regression. So this would be a new process -- new inputs.

COMMISSIONER KEMERAIT: Okay. And when

will this new process be operational? In time for this winter season?

MR. PEELER: So -- no, it won't. We're working on now how to do it. It requires another vendor to collect that data. Another tool, I should say, to collect that data such that it can be fed into that regression model. So we're -- we're in the early stages of evaluating how to do that. So it won't be ready this year.

COMMISSIONER KEMERAIT: It's not being ready this year. So you're thinking 20 -- can you give me an idea of when you think it might be ready, if you know?

MR. PEELER: I honestly don't know exactly when we'll be able to get it in production. And it'll be in phases, of course. So we'll start out with, like I said, a smaller, you know, dozens of inputs into it. But we've got to get a -- we've got to get an interface tool that can take that more granular data and put it into our larger model. So I just don't have a firm date on it. I'm sorry.

COMMISSIONER KEMERAIT: Okay. Thank you.

COMMISSIONER DUFFLEY: So, Mr. Gillespie, I just wanted to thank you for your candid answer regarding the Allen plant and if you had a crystal ball, but this was the Company's first ever load shed event. But it does provide comfort that in future scenarios where we have extreme winter weather headed to North Carolina, the decision-making process will be a bit different. So I appreciate that answer.

MR. GILLESPIE: You're welcome.

COMMISSIONER DUFFLEY: So with that, if there no more questions, we'll move to Public Staff.

(No response.)

MR. METZ: Good afternoon. Dustin Metz Public Staff. Prior to the event, Duke Energy had discrete plants that were in extended outages. Notably, Robinson nuclear power plant and W.S. Lee combined cycle plant. As I filed testimony in the DEP fuel rider case, Robinson nuclear power plant had an extended outage. And as Mr. Lawrence had filed testimony in the DEC fuel case, the W.S. Lee unit outage took place.

The W.S. Lee unit outage is still under

investigation, but it's not clear what caused the failure given the type of damage. Typically, those complete full-unit outages prior to the end of the year, and unit outages of those of two plants in this case, were uncommon.

As of December 22nd, even with the existing plant outages in question, Duke was still projecting to have adequate reserves. That shows the dynamics of how quickly things transpired between the 22nd through the 25th. Allen units 1 and 5 were in extended plant reserve condition throughout 2022. I'll discuss the importance of this item later.

A high-wind event occurred as a storm moved across the state -- states, causing power outages and system restoration. As system reserves became narrower, storm restoration activities may have contributed to larger than expected load increases, given the phenomenon of cold weather pickup. However, tradition -- traditional reserve margins should have accounted for this level of very -- variation and system load estimates.

Transitioning to the load shed event.

Traditionally, overall electric load is less on the weekend compared to the workweek. This is also true of holidays, as there's less people, generally, working in large industries and commercial locations. As the cold weather moved across the nation, Duke did evaluate the daily changes in load given colder than expected temperatures.

Duke did take actions to look for imported -- imported power from neighbor utilities. A large lesson learned, for at least myself from this event, was the assumption of firm power from our neighboring utilities. Firm is not dependable during a system emergency as we entered EEA-3 and other utilities and RTOs also entered EEA-3.

During the peak of the load shed event, multiple utilities entered EEA-3 and needed self-preserve before aiding other utilities. However, even if the firm and nonfirm -- firm purchases were able to be delivered, we would still have needed to have the controlled load shed event. This was contributed by the loss of merchant power generation, which I'll also discuss later.

It's important to note, Duke's transmission system was not constrained during the event. There were no TLRs issued. The transmission system was available to use. There was just no energy or capacity to be found or imported. The Carolinas did have merchant power generation plants go offline during critical periods of need. As I noted recently in my DEP field testimony, network customers that purchase power from a merchant power plants essentially became Duke load.

Duke Energy -- Duke Energy generation plants, like merchant generation, also experienced issues that need to be derated. Duke placed Allen steam generation station in EPR for 2022. The EPR status, simplified, means that generation plant would take a few additional days to start comparative that the plant was not in the EPR status.

Given the generation plant was in EPR and when Duke started to identify the load increases with updated weather conditions, Allen could not have been started in time to mitigate the Christmas Eve load shed event.

Duke's automated load shed tool did not work as planned. The failure of the tool exacerbated outage time for customers. There was unclear communications to customers. But it's important to note that this was a complex period with storm restoration activities, curtailing load, the load shed tool failing, and addressing plant -- generation plant issues.

Transitioning to the Public Staff concerns and observations. In whole, the overall timing of multiple events overlaid a set of conditions that compounded upon one another, causing the need to have a controlled load shed event. As the Commission is cognizant of, we have multiple layers of defense. We have reserved margin. We have imported power. We have DSM. There's multiple layers of defense. It's just unfortunate in this circumstance that different layers of the defense failed.

I've highlighted in both DEC and DEP's most general rate cases on a degrading plant performance of Duke's generation plants. I've noted the concerns about staffing and significant decreases in ONM from the amounts approved and already in base rates at the time of the event.

To the extent that these events continue to take place, degrading plant performance and reduction of staffing, cutting ONM, following a prior rate case, the Commission may need to provide more oversight to Duke's annual operations and system maintenance. However, it is noteworthy that the system is in a state of transition as the generation fleet -- certain aspects of generation fleet are reaching near end of life. And these older plants were not designed to be operated in the current state they are today.

The response time to bring a plant back on online and staffing for an EPR plants should be reevaluated and potentially fully dissolved during December through March.

PJN's curtailment of firm and nonfirm energy did contribute to the need to curtail load in the Carolinas.

Solar generation resources did perform as designed, but this event adds the need to emphasize the difference of winter planning versus summer planning. Their curtailment event took place at approximately in the early morning hours before solar could fully contribute its full nameplate rating.

Given pressure drops on Transco Pipeline, the addition of new natural gas generation and retiring coal coupled with winter morning peaks, there is a minor concern of longer term resource diversification and single-point failures. Load response to cold weather shall be implemented and load forecasting go forward.

While I do not have an exact solution to this challenge, there needs to be better communication with customers and utility neighbors. There needs to be more distinction in the difference in storm restoration versus conservation and energy usage to their notification that load shed is imminent. To the extent possible, future evaluation of other media platforms and requests for conservation need to be made. Local news, radio, social media.

To the extent that new combined cycle plants are proposed to be built, they should include a bypass stack after the combustion turbine. This will enable at least partial generation of the assets and remove a single point of failure, make further enhancements to Duke's existing winter preparedness checks, and -- the lessons learned from the winter storm.

Lessons learned from 2014 and '15 were in place and most likely prevented similar issues from 2014 and '15, which would have potentially exacerbated the need for a larger load shed event.

Utility configuration control and turnover construction to ensure that they have it documented on what aspects of the plant need more routine checks during the winter, and the RLS updates and testing were not robust.

That concludes a general summary of my investigation.

COMMISSIONER DUFFLEY: Okay. Let me check in with the court reporter. How are you doing? Do you need a break? Okay. Let's take a 10-minute break. And we'll be back at 12:33 to finish the hearing.

(At this time, a recess was taken from 12:25 p.m. to 12:36 p.m.)

COMMISSIONER DUFFLEY: Let's go back on the record. As I understand, Mr. Metz, you're done with your comments at this point?

MR. METZ: That is correct.

COMMISSIONER DUFFLEY: Okay. So I just have a couple of generic questions about -- is there anything that you heard here today that you would like to speak to?

MR. METZ: Thinking. It was a long conversation. I believe the Duke panel's presentation of the lessons learned are consistent with the Public Staff's overall investigation.

COMMISSIONER DUFFLEY: Okay. And you're satisfied with the information that the Company has provided you in your investigation?

MR. METZ: Yes. We've had multiple meetings, even after those discovery requests, and the Company has been very forthcoming and had an open conversation with the Public Staff throughout the overall investigation.

COMMISSIONER DUFFLEY: And you've reviewed the South Carolina reports?

MR. METZ: I have.

COMMISSIONER DUFFLEY: Are you in general agreement with findings of that report? Or are there any discrepancies that you would like to identify for the Commission?

MR. METZ: Some work to do, I believe. It's factually accurate. I think there are certain contexts that maybe could be provided on certain elements. For example, the cold weather event that came before the storm -- the cold weather pickup. There are factors that may have contributed to the need to do load shed event that maybe could have gone into more detail. But the overall report is factually accurate.

COMMISSIONER DUFFLEY: And you're satisfied and comfortable with the additional processes and the -- that -- that Duke and -- Duke Energy Carolinas and Duke Energy Progress are going to be implementing for future extreme winter weather?

MR. METZ: I believe their -- their winter -- winter weather program is a tool that has been in place and will always be -- continue to refine. To go further down into that detail. To give you an idea of one of the events that took place.

There was a recent modification at one of the power plants, and they put in a new control box. Let's just say, it's a four foot by four foot control box. And it had a pipe coming into the bottom of it, and that pipe had sensory cable or a communications cable. And as you're taking a step back, and you're looking at this panel, the bottom of the panel was probably about -- about your waist. So the top of the panel was a little bit taller, and it's outdoors.

And one of the events that took place, there was approximately about an inch gap between where the insulation came up to it where it went into the bottom of the box. And sure enough that inch gap, which you really wouldn't see from a natural observation point because given where it's proximity to the ground, you wouldn't have picked up on it all.

But sure enough, that was one of the lessons -- one of the items that contributed a need to derate. But a lesson learned coming out in 2014 or 2015, those plants actually -- the full plant would have went offline, were able to mitigate the need to go fully offline and just derate the overall plant. That's probably a very long answer to what you're asking, but --

COMMISSIONER DUFFLEY: Thank you for that answer. So Commissioner questions? Commissioner McKissick.

COMMISSIONER KEMERAIT: So I take it, based upon your response to Commissioner Duffley's questions, there are no additional measures that you would suggest or recommend that Duke take at this time to address the problems that were faced as a result of Winter Storm Elliott beyond what they have already proposed?

MR. METZ: And I have a caveat with the additional items that I outlined in the beginning because trying to break it apart in the three discrete parts -- and I look over to Mr. Holeman. So, okay, well, he had his operation teams and is responsible for maintaining system reliability. They did their job to a tee on a day that they needed to do it at every given hour. I don't mean to call out the Duke team, by no means.

But I look over to Mr. Gillespie. Well, okay, I'm looking over at plants. There were some lessons learned that can be implemented from plants. But that is a continual process. And I forget the name tags. Ms. Sims. Just looking over to the communications policies. I don't mean to call you out. The Public Staff would like an enhancement on the communication protocols that take place.

COMMISSIONER MCKISSICK: And what would that be?

MR. METZ: I don't have a perfect solution to those but more transparency leading up to the event. So calling for calls for conservation, even before we get there. But I agree with Mr. Holeman's comments on saying conservation is a nice thing, but how can he plan for that on that given day? He can't, but if we never call on it, then we'll never get it.

Trying to look at what -- how communication is presented branching further into different avenues of social media. So let's say, for example, if we want to increase communication, and we propose just to place it on the Duke Energy web page. I don't know who is looking at the Duke Energy web page on Christmas

Eve.

I mean, I say that in jest, but that's something important. How? I don't have an answer, but how can we get out this -- the norm that we live in today, and branch out to the more social media that exists today? Getting it to the right channels or avenues where we can get that information in front of everyone.

COMMISSIONER MCKISSICK: So the suggestion would be using social media more effectively in the event there might be a load shedding event?

MR. METZ: Yes, Commissioner. Maybe a standing protocol to inform local news agencies. Maybe we can get across the six o'clock news. I know that's still sometimes watched in today's world. But, yes.

COMMISSIONER MCKISSICK: Are there any other observations you would like to hear in terms of potential modifications or changes or enhancements that might be recommended?

MR. METZ: Not at this time.

COMMISSIONER MCKISSICK: Thank you.

COMMISSIONER DUFFLEY: Okay.

Commissioner Kemerait?

COMMISSIONER KEMERAIT: And, Mr. Metz, just a follow-up on one of your comments about -- you said one of the Public Staff's concerns was about staffing. Can you be more specific about what the concern about staffing is?

MR. METZ: So this is -- this is a very complex item as well. And I said it, so I need to own it. There is some concern to the extent if -- if we have technicians or craft who are responsible for doing these reliability checks and daily operations or even being staffed to respond in the event that -- that comes up. Those people should be there at the plants.

We have to be cautious of having individual employees potentially wearing too many hats. While having an individual employee -- what we usually traditionally call -- would be multi-craft. That is -- it is a cost saving avenue, and I believe the Company has implemented -- I know the Company has implemented those based upon conversations.

However, are we -- I don't have an immediate answer, but have we gone maybe a bit too far in overburdening too many people with too many responsibilities, and we need to bring more staffing back and make them -- instead of having, as multiple hats, they can just start wearing the singular hat or at least just two hats and not four hats.

COMMISSIONER KEMERAIT: And as part of your concern about staffing, what I thought you were also going to be saying, but you didn't say it -- so I just want to have clarification. Did you -- does the Public Staff have concern that Duke had inadequate staffing over Winter Storm Elliott? Or is that not part of your concern?

MR. METZ: Part of my investigation did not evaluate the -- maybe the layered complex -- complexity of being -- with this event taking place on Christmas Eve and natural employees taking the holiday break. Where we did look more and closely to it was, for example, was the EPR status with Allen. But Allen does share in those resources with Marshall steam station.

COMMISSIONER KEMERAIT: So that's more specific to your staffing concern? About sharing of resources between those two -- those two generation units?

MR. METZ: That is correct.

COMMISSIONER KEMERAIT: Okay. Thank you.

COMMISSIONER DUFFLEY: Okay. The Commission would like to thank the Public Staff for its thorough investigation of this event. And thank you for your comments today. So I'll turn it back over to the Company. We do have one more Commissioner question for you. Before we have that Commissioner ask their question, is there anything else that the Company would like to state after hearing Public Staff's comments?

MR. JIRAK: Yes. If we could open it again. In general, no major disagreement at all with the facts or opinions offered here. I think maybe we probably could offer just a little more color response on two topics. One would be sort of our evolving communication processes and protocols, which Ms. Sims can speak to. And then Mr. Gillespie can speak a little bit more to some of those staffing issues that we were just discussing. So as soon as you want to start.

MS. SIMS: Okay. Yes. Yeah. I do

appreciate the point of view and the recommendation. I think it makes a lot of sense. And the good news is that we have looked more at -- at our alignment with our GLRP plan. And as we move through the EEA statuses, how we would communicate with customers, and we have been able to make sure that we have the news media, as well as social media, and any other digital outreach that we can do during that time.

Understanding that our -- that our customers use various channels and means to get that information. So we have been able to add that in and -- and I will make sure to update that in any other information that we give to you.

MR. GILLESPIE: I think you heard -- I think you heard a detailed and accurate report out from the staff today. I listened to this -- this discussion on layers of defense, ONM spending, and reliability. And it was mentioned, these plants are not operated in the way they were designed. These were designed as baseload -- as baseload plants.

We cycle them up. We cycle them down.

You just go stand on the top of one of our largest coal plants when it was cold, stay on top of the platform, and let it come up to operation, you'd be a foot higher than what you were when you started.

So that's a foot of stress. That's metal getting stretched and contracted over time, and it creates operational complexities that -- that our -- that our teams are dealing with. And then with this -- with the concerns over staffing. I think it's fair to be concerned over staffing. We look at staffing on a -- on a frequent basis.

We're all the time asking, do we have staff in the right spot, in the right -- at the right time, with the right skills. And we work hard to maintain staffing levels. And in this particular event, other than the decision to release a few of the Allen folks well before this happened as they were going on holidays, I would tell you that we had -- our staff was available. Our craftsmen, our engineers, and our leadership was on the sites that were impacted.

And when you look at the outcomes --

you know, our plants were back in service by the 25th. So the plants that had issue on Christmas Eve day were quickly put back into service. This -- this concern over multiskilled or over -- overburdening the plant staff is one that we monitor, and then we watch. And we're trying to make good decisions that are good for the plant, and also good for the customer. In terms of what -- in terms of where our rates are ultimately set.

So I think the -- I think what I heard from the staff today are concerns that overlay our own concerns or questions that we ask ourselves daily. And they drive decisions that we make on a daily basis. And the work they do is -- is of benefit to the state.

MR. JIRAK: Thank you, Mr. Gillespie. And I will just note that, obviously, we have a number of action-item follow-ups that we'll be working on based on the Commission's requests. And we'll get those filed as quickly as we can. One item I'll just flag for awareness is the request for the ORS -- the confidential version the ORS report.

To give full context of that, we will be providing that along with our response in those Dockets. They're publicly available as well. Just to give the fuller perspective, as you've heard, regarding some of the nuance that we -- that we think was left out of that report. So you'll have the full context of both the confidential report as well as some of our written response to the report as well. Thank you.

COMMISSIONER DUFFLEY: Okay. Thank you, Mr. Jirak. And we have one question by Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Again, breaks are dangerous because they let you think of things to ask. So don't -- don't ask for breaks if you don't want more questions.

I have two questions that really connect the dots between what we're talking about here today and what we're going to be talking about in CPIRP proceedings upcoming. One of the questions, I think, is, I think I know the answer to it. But -- and it's a fairly obvious question. But if you don't ask the obvious question, sometimes you don't know whether you know the answer to it or not.

Since this happened to both Companies, I think I know the answer. But let me ask it, if the two Companies had been operating as a single balancing authority, would any of this have gone down differently or not?

MR. PEELER: I'll start.

COMMISSIONER CLODFELTER: Okay.

MR. PEELER: Sam can jump in. So -- certainly, the combination of the two Companies create some efficiencies. It creates some efficiencies in long-term planning as well as daily operations. So, for example, the reserve -- some of the errors that are captured in reserve margin are reduced because you could plan for one single large contingency, not two, for example -- for a combined system.

So our day-ahead planning reserve requirements would be reduced. Now, on an ongoing basis, that's economic and reliable. However, in this case, we were -- those were depleted. So it wouldn't have prevented a load shed event. It may have created some additional efficiencies that could have -- could have made it less impactful, but there would have still been a load shed event.

COMMISSIONER CLODFELTER: That's -- That's what I thought the answer was. But, again, since we're going to be talking about combining to a single balancing authority in the CPIRP proceedings, I just wanted to hear you talk about how it would have played out if you had them.

MR. HOLEMAN: Yeah. The only thing I'd add -- I mean, it's -- to me in my simple mind, when we combine -- when we -- if we combine, you're going from two to one. And so processes are simpler. You're doing things once. You're having one balancing authority. But I agree with Mr. Peeler, that wouldn't have prevented this.

COMMISSIONER CLODFELTER: You still would have had the load shed.

MR. PEELER: It would have created some efficiencies. It would have made some things better. And it certainly would help us as we take the next steps for long-term planning. Long-term planning for a combined system is more efficient than planning for two.

So as we need a bigger reserve margin, it's more efficient to do it with one system than with two, for example.

COMMISSIONER CLODFELTER: Okay. Thank you for that. Mr. Gillespie, second question is for you. And, again, it's a -- it's a sort of a connecting the dots thing. Did this experience affect, in any way, your thoughts about future resource additions? And, specifically, the type of resource. Especially with respect to gas resources. Would you have been better off last December the 24th if you'd had more aero derivatives as opposed to F-class CTs?

Would you have been better off if you'd had two or three rice units in your fleet? Did anything that happened last December cause you to think differently about what kind of resources you might need to add?

MR. GILLESPIE: It does. And you know, those -- those thoughts are generally integrated into our IRP now. And if you look, the biggest thing is that a resource that can deliver around the clock is of great -- is of great value.

I was asked a question about solar and solar performance in -- in an audience, and I think my answer was different than they expected. Because they asked did it perform as expected, and I said, well, it did. And when the sun came up, the solar delivered. But when you look at where the peak occurred in this case, it was -- it was -- it was prior to where solar was designed to deliver.

So solar did exactly what we expected it to do. But what this highlights is -- is either the need with that solar for greater storage, either through a pump storage, batteries, new storage technologies, certainly the -- certainly gas plays in -- plays a role in -- in the future.

And then, you know, just, ultimately, the ability to have that energy available in whatever form 24/7 and not be -- not be reliant upon, you know, which -- which face the planet is facing, will be -- will be important to us.

COMMISSIONER DUFFLEY: So this technical conference has been very helpful. What we've heard here today with improving processes as well as adding additional processes to deal with extreme cold weather sounds constructive. So we thank you for coming in today and providing that information. And we thank, again, the Public Staff for their investigation of this event. We look forward to the filings that we'll be receiving after we end this technical conference. And with that, we are adjourned.

(Technical Conference concluded at 1:00 p.m. on September 26, 2023.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA )
COUNTY OF NEW HANOVER )

I, Scarlett O'Rork, CVR, the officer before whom the foregoing technical conference was conducted, do hereby certify that the foregoing proceedings were taken by me to the best of my ability and thereafter reduced to typewritten format under my direction; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this hearing was taken, and further that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 29th day of September, 2023.

Scarlett O'Rork

Scarlett O'Rork, CVR
Notary Public #202314200262
Notary Expiration: 05/18/2028