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PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Tuesday, April 19, 2022

TIME: 9:30 p.m. - 1:30 p.m.

DOCKET NO: M-100, Sub 163

BEFORE: Chair Charlotte A. Mitchell, Presiding
Commissioner ToNola D. Brown-Bland
Commissioner Lyons Gray
Commissioner Daniel G. Clodfelter
Commissioner Kimberly W. Duffley
Commissioner Jeffrey A. Hughes
Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

Investigation Regarding the Ability of North Carolina's Electricity, Natural Gas, and Waste/Wastewater Systems to Operate Reliably During Extreme Cold Weather

VOLUME 1

A P P E A R A N C E S:

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FOR DUKE ENERGY CAROLINAS, LLC, AND
DUKE ENERGY PROGRESS, LLC:
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Jason Higginbotham, Esq.

FOR PIEDMONT NATURAL GAS COMPANY, INC.:
Jim Jeffries, Esq.

FOR FRONTIER NATURAL GAS COMPANY:
Jim Jeffries, Esq.

FOR PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.:
Mary Lynne Grigg, Esq.

FOR PUBLIC STAFF:
Lucy Edmondson, Esq.
John Little, Esq.

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P R E S E N T E R S:

FOR DOMINION ENERGY NORTH CAROLINA:

Jacqueline Vitello - Director of Power Generation

J. Scott Gaskill - General Manager of Regulatory Affairs

Mike Barmer - Manager of Electric Transmission System Operations Planning

Wesley Walker - Senior Assistant General Counsel

Chris Dibble - Director of Power Generation Operations

FOR DUKE ENERGY CAROLINAS, LLC, AND DUKE ENERGY PROGRESS, LLC:

Sammy Roberts - General Manager, Planning and Operations Strategy

Joe McAllister - Managing Director of System Optimization

FOR FRONTIER NATURAL GAS COMPANY:

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Bruce Barkley - Vice President, Rates and Gas Supply

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Neil Moser - Director, Gas Engineering & Asset Planning

Jeff Patton - Manager, Gas Pipeline Services

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FOR PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.:

Bill Raynor - Manager, Engineering Projects

Scott Swindler - Director, Gas Operations

Rose Jackson - Director, Gas Supply Services

FOR PUBLIC STAFF:

Jordan Nader - Engineer, Energy Division, Natural Gas Section

Dustin Metz - Engineer, Energy Division, Electric Section

Bob Hinton - Director, Economic Research

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CHAIR MITCHELL: Good morning. Let's come to order and go on the record, please. I'm Charlotte Mitchell, Chair of the Utilities Commission. With me this morning are Commissioners Brown-Bland, Gray, Clodfelter, Duffley, Hughes, and McKissick.

This Technical Conference is being held this morning in Docket No. M-100, Sub 163 which is titled 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.

Due to the widespread outages experienced in Texas and the south-central United States during February of 2021, as well as the results of a joint inquiry into the Texas outages undertaken by the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation, the Commission opened an investigation to consider whether North Carolina's electricity, natural gas, water and wastewater systems are prepared to operate reliably during extreme cold weather events and whether or not Commission's rules require changes in order to ensure reliable service.

The Commission issued an Order on

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January 26, 2022 initiating the investigation. The Order made, as parties to the proceeding, the largest North Carolina's jurisdictional electric, natural gas, water and wastewater utilities and required these utilities to file responses to a series of questions related to their extreme weather preparedness by February 23rd, 2022.

The Order also scheduled technical conferences to be held on March 15th as well as today, April 19th -- it's April 19th, for the parties to present their responses and answer follow-up questions.

On March 15th, the Commission held the first Technical Conference which focused on the water and wastewater utilities. We're here today for the second Technical Conference which will focus on the Preparedness of our natural gas and electric utilities.

We will hear this morning from Dominion Energy North Carolina followed by Duke Energy Carolinas and Duke Energy Progress. Then Piedmont Natural Gas, then Public Service Company. And, last, we'll hear from Frontier Natural Gas Company.

The Public Staff, which presents the Using and Consuming Public in matters before the Commission, will participate in this Technical Conference as well.

This proceeding this morning is being transcribed. The transcript will be filed in the Docket as soon as it is available, so let's just remember to treat the court reporter well.

Before we begin, I'd like for the parties to identify themselves for purposes of the record. We'll start with utilities.

MS. GRIGG: Good morning, Chair Mitchell. I'm Mary Lynne Grigg with the law firm of McGuireWoods, here on behalf of Dominion Energy North Carolina. Also here is Ms. Lauren Wood Biskie who is Senior Counsel for Dominion Energy, and Kristin Athens, also here from McGuireWoods.

CHAIR MITCHELL: Good morning, Ms. Grigg. Let's see. Is there anyone from Duke that wants to make an appearance, at this point?

MR. HIGGINBOTHAM: Good morning, Chair Mitchell, Commissioners. My name is Jason Higginbotham, an attorney on behalf of the Duke Energy Carolinas and Duke Energy Progress. And also here for the Company presenting today are Sammy Roberts, a GM of Transmission Planning and Operations Strategy, and

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Joe McCallister, Managing Director of System Optimization.

CHAIR MITCHELL: Good morning. Mr. Jeffries, I see you approaching.

MR. JEFFRIES: Good morning, Madam Chair. I'm Jim Jeffries with the law firm of McGuireWoods. I'm here today on behalf of Piedmont Natural Gas Company and also Frontier Natural Gas.

CHAIR MITCHELL: Good morning, Mr. Jeffries. Looks like somebody got the better of you, somebody or something.

MR. JEFFRIES: I have some new parts.

CHAIR MITCHELL: Understood.

MS. GRIGGS: Good morning, Chair Mitchell. Again, Mary Lynne Grigg with McGuireWoods, again. Also here on behalf of Public Service Company of North Carolina, doing business as DENC.

CHAIR MITCHELL: All right. Thank you for that clarification.

MS. EDMONDSON: Lucy Edmondson with the Public Staff. We appear on behalf of the Using and Consuming Public. Also appearing with me is John Little, also a Staff Attorney. And our technical staff today that will be participating: Jordan Nader,

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Engineer with the Energy Division Natural Gas section, Dustin Metz, Engineer with the Energy Division, electric section, and Bob Hinton, Director of the Economic Research Division.

CHAIR MITCHELL: Good morning, Ms. Edmondson and all members of the Public Staff. We have -- before I turn Dominion loose this morning, there is a motion that's been filed in the Docket on behalf of Duke attorney Jason Higginbotham, motion for pro hac vice. We will allow that motion and the Order will be issued in the Docket shortly. With that, anything else before we begin?

(No response)

CHAIR MITCHELL: You may proceed.

MS. GRIGG: Good morning, Chair Mitchell. I'll just make introductions, if I may. Our primary presenter, on behalf of Dominion Energy North Carolina, is Jackie Vitello, Director of Power Generation. We also have Mike Barmer, who's Manager of Electric Transmission System Operations Planning, and Chris Dibble, Director of Power Generation Operations.

We also have here two representatives from PJM. They will not be presenters, but to the extent

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that the Commission has questions, they are -- or the Public Staff has questions, they are available. And they are Matt LaRoque who is Senior Manager, Regulatory Affairs, and Donnie Bielak who is Senior Manager of Dispatch.

MS. VITELLO: Thank you, Mary Lynne. Hello. Thank you for having us here today at the Technical Conference. My name is Jackie Vitello, and I'm Director of Power Generation Regulated Operations. My group is responsible for offering our regulated fleet into the PJM market.

Along with me, I have Chris Dibble who's the Director of Power Generation Operations, and Mike Barmer who's the Manager of Electric Transmission System Operations and Planning.

We have prepared slides that summarize the questions from the January 26th Order. The reason for this investigation is to ensure that we do not have an event in North Carolina like ERCOT had in February of 2021 due to the extreme cold weather events.

To begin, I'd like to discuss our efforts around winter preparedness since 2014. We had a major Polar Vortex in January of 2014 that I'd say was a turning point for winter prep in our area. PJM was very close to not meeting their reserve requirements and called a voltage reduction action to maintain reliability.

Across PJM, generating units had a high overall forced outage rate which led to changes in the PJM market design as well as Dominion's own winter preparedness. Dominion Energy has invested significant resources in winterizing our power stations. This work includes heat trace maintenance, designing key equipment and doors, pre-winter insulation inspection, and building both temporary and permanent Windwall enclosures.

We also winterize our equipment and have sub-freezing protocols in place to maintain systems during extreme cold weather. The efforts and investment into unit winterization have been successful or by the fact that over the past several winter peak events, we have only had one incident of a unit trip due to suspected freezing. Fuel diversity and flexibility are also important in winter reliability.

On our system serving Virginia and North Carolina, about half of our gas fleet has dual fuel capability. For example, our Peaker plants can run on

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oil, a valuable dual capability to ensure reliability and affordability. If natural gas is scarce or if the price is high due to demand, we can switch to oil.

ERCOT does not have a capacity market. Capacity markets are foreign markets which direct investments a few years ahead of when electricity needs to be delivered. As a result, there's little incentive in ERCOT for generators to secure firm fuel supply or to maintain winterization programs. PJM has a robust capacity market and Dominion participates in that market.

So one of our follow-up questions from Public Staff mentioned the significance of FRR, in switching to FRR. I'd like to reiterate that FRR is another way to participate in the capacity markets. Our units are still capacity resources and follow the same requirements that come with being in the capacity market. For example, they still have must-offer requirements in the day ahead and realtime markets, and we're still subject to capacity performance penalties.

Due to the Polar Vortex in 2014, the main PJM change to their capacity market was implementing the capacity performance penalties in 2016. This

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incentivizes capacity resources to invest in equipment to ensure reliability during extreme cold weather events. This was proven during the cold snap of 2018. Gas generators and PJM had a forced outage rate of 32.7 percent in 2014, and then that dropped to 18 percent in 2018.

For the second question, we were asked what changes we will be making to comply with NERC's new cold weather prep standards that take effect April 1st of 2023. We're continuing to evaluate our current processes to ensure alignment and compliance with this standard. We're also looking for process improvement opportunities.

Along with the cold weather operations questions, we were asked how wind and solar played a role. But with the cold weather, solar generation is not impacted unless there's snow cover. And we think about the winter peak, it's going to happen at 05-0600. And the sun's not going to be shining, so we aren't really relying on that Solar Generation anyway.

Our wind turbines are designed for -4 degrees Fahrenheit. And in the last 20 years, we've recorded temperatures. The lowest was 14.6 degrees Fahrenheit, so we don't see the cold weather being affected or affecting those wind turbines.

Finally, I'll touch on the reserves in PJM. So primary reserves are megawatts that can be achieved in 10 minutes or less. It can include both online and offline generation, so we mostly use our Bath County pump storage or hydro run-of-river or our quickstart CTs that are offline, but can be online and producing megawatts within 10 minutes. There are changes coming to the reserve market October 1st of this year, and that can be discussed at a later date.

Currently, Dominion Energy is a participant in the Reserve Share Agreement known as VACAR, the Virginia-Carolina Reserve Sharing Operating Agreement, which is separate from PJM and was entered into before Dominion became a part of PJM.

Each member's obligation is based on the ratio share of the member's peak load obligation. For the current year, Dominion's VACAR reserve requirement is 568 megawatts, which Dominion maintains at all times and is separate from the PJM reserves. You may not double-count your reserves for both systems. As the Commission is aware, Dominion Energy North Carolina provided notice earlier this year to the other VACAR members of the need to exit the existing

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agreement. We made this decision as a result of the upcoming changes in the PJM Operating Reserve Market.

Moving on to Questions 3 through 6. These questions focused on the weather and Load Forecasting. Dominion Energy has two contracts with two weather vendors that provide hourly weather forecast for load modeling and planning. The forecast include temperature, cloud cover, relative humidity, precipitation, wind speed, and wind direction.

Aside from the weather vendors, Dominion also uses vendor load forecast models in addition to an internal model to predict load forecasts. PJM also creates their own load forecasts. The 7-day forecast model is also used to predict extreme peaks. We have an internal forecast to predict cold weather alerts for the PJM RTO and the DOM Zone.

For the past three winter peaks, so 2019 to 2021, Dominion's dead-head load forecast was within .7 percent to the actual peak load. See the table on this slide to see how our forecasted temperatures for one day ahead and three days ahead before the actual events and how well our forecast performed.

All right. For the 7th and 8th question, we move into power plant performance during the winter peaks. The first question was around forced outages due to frozen equipment. And like I mentioned earlier, we had one event in the past three winters that was forced out and it was a frozen component, and it lasted less than four hours. When you look at our forced outage rates compared to PJM during the winter peaks in both 2014 and 2015, we were at 11 percent, and the PJM RTO was 22 percent in 2014. And then in 2015, it was 4 percent for Dominion and 12 percent for the PJM RTO.

Our fleet consists of about 9,500 megawatts of units that are capable of running on natural gas and about half of our gas fleet is dual fuel capable, meaning that it can run on oil instead of natural gas. Like I mentioned in the beginning, this dual fuel capability is essential to our reliability. If we were not able to secure gas, for some reason, we would switch these units to run on oil.

Now I'm going to turn it over Mike Barmer to discuss transmission questions.

MR. BARMER: Good morning. Mike Barmer. I'm the manager of System Transmission Plant -- Operations Planning at Dominion Energy. There were several questions around load shed and load

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curtailment activities and how we managed that within our company, so I thought we would start out and just kind of go through the process, just so you understand how we do this.

First of all, individual -- we track everything in our company by Individual Accounts, so as a -- it could be a residential customer, it could be all the way up to a gas customer. Within our customer accounting system, we have a field in there that is called a Special Condition Field, and you don't really have to -- you can see the chart.

You don't really have to look at all of the numbers here, but it's a segmentation of codes that we would use in that field in the customers' account that basically breaks it down by critical infrastructure, high profile or public interest-type customer, and depending on the type of customer it is in terms of commercial, environmental, public safety or whatnot.

So we use this matrix to identify the code that we use. And once that's attached to the customers' account, then this was actually developed more for restoration activities after major events so that we can help prioritize our restoration activities around critical customers or critical infrastructure,

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but that same information translates down to the load shed process, load shed program.

One thing I'll note right now is so in our company, we've interacted with most of our customers over many years now to distinguish which ones fall in which category, so existing accounts are pretty much set. Most of those don't change a lot over years' time, but we do regularly update or check those.

A specific question was around natural gas pressure stations. The accounts that we have that are associated with electrically-powered compressor stations from natural gas are all served from our transmission system. Our Load Shed Program does not shed load on our transmission system. It's designed to shed load on the distribution level. So any customers who are fed from -- directly from a transmission feed aren't part of our load shedding process.

So what we do as a company, we take that information from those Individual Accounts that are now associated to individual distribution circuits, and we review those each summer or prior to each summer or prior to each winter load period. And what we're looking at is are there any changes or any

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additions that have been made from the prior years' list of special condition customers, critical infrastructure. Just because they're critical infrastructure doesn't mean they get excluded from load shed.

We, as a company, then approach those companies that have either additional accounts that have been labeled as critical infrastructure ones that have changed. And when we talk to them, we ask questions. Do you have backup generation to serve critical process needs within your facility, because we don't know, as a company, what their criticality is and their processes. All we know is when they say this is a critical location for us, but we dig a little deeper. So we want to know if they can sustain a 15-minute outage, which our Load Shed Program rotates every 15 minutes.

So, in theory, it will shed your load. 15 minutes later, it will shed another block of load and restore the first block. So with that process, you would only endure a 15-minute interruption. Many processes, and we've talked to many of them, we've talked to all the water treatment-type facilities -- that was another question in there. In talking to them, they all indicated that they can sustain a 15-minute interruption.

The ones that maybe had some questions or concerns about maybe chemical using in the facility or whatnot, they have backup generation to keep those processes and controls in place during a 15-minute interruption, so we don't exclude water treatment and water pumping stations for that reason, because they've indicated that it doesn't create a major issue for them.

Now, we do categorize all of our customers. You can see this categorization in different groupings based off of all those factors; the condition codes that we get from the accounts, plus our discussions. And there are a group of what we call Z group customers that are excluded. Those are the ones that don't have backup generation, or even if they had backup generation and can't cover the specific needs and creates a process issue with them internally.

Just for reference, so about half of our customers are in the Load Shed Program. The other half are excluded, and you can see that in the chart. That's -- the chart is a company-wide number. I did put a note at the bottom just for reference here. So

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in North Carolina, we have 122 circuits. 34 of those are in the load shed process. That percentage is lower than it is in the rest of our service territory. One of the reasons being over the past three to five years, we've had a lot of influx of distributed generation on the distribution system, and the intent of load shed is to shed load, as is sounds, not to shed generation.

So if we had circuits that have a net positive generation on it, we do not want to shed that because you're creating a worse problem, so we've excluded those as well. So in looking at the numbers, North Carolina has less circuits within the load rotation than the rest of our system does.

One thing to note too is, you know, we haven't used this in a long time. I mean, the last time we actually did a system-wide load shed was in 1994, so it's been long time, and we've had a lot of cold weather since then.

In the way that load shed works, just for information too, is our Company's divided into three major regions: north, central, and the east region. North Carolina falls within the east region of Virginia. So when we go through a load shed process,

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we drop a circuit in each region one at a time, so we're not dropping a complete region, we're not dropping -- unless it's a major need to drop a lot of load, we shouldn't be dropping a significant number of circuits within any one region at any one given time. But it is spread out, so it's not targeted to one region for the whole block, if you understand what that means.

Another question that came up was about training on our process system operators on the use of load shed. We have an annual training. All of our operators go through annual training for Load Shed Plan Execution. Part of that is we review all the components of load shed. I say load shed. It's really the Load Curtailment Plan, which involves a lot of parts. One of them is Voluntary Load Shed. One of them is Voltage Reduction. One of them is actual load shed where we initiate the load shed. So it's a fair -- it's various steps to that process from the beginning to the end.

The operators go through that whole process, review everything that goes on with that process so they're very familiar with it in the event they have to use it. It also includes hands-on simulation. We

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have a simulator that we use in training. We throw scenarios at the operators, and part of that process is going through the Load Shed Program. So they get hands-on, so it actually goes through the process. They see the actual circuits operating as if it was real, but it's actually in the simulator, but they see how it looks when it would actually have to take place in realtime.

And then we also test our internal communications. We always want to be sure that everybody within our company is aware of what's going on because it could be happening very quickly. So they go through the internal paging e-mails and groups like that to be sure that everybody is aware of what's going on. And it's all pretext with drills so that everybody knows it's a drill, but they do see that the information coming through as we progress through from a voltage reduction all the way up to a load shed.

We also have bi-annual drills that we coordinate with PJM, and those are usually one-day events. So the operator, whoever -- whatever operators are on shift that specific day that they're doing the drill gets that opportunity to do that. I didn't mention, the other training, all the operators

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go through it. Our training process is that all of our operators go through training quarterly for a week. So every quarter, they're in a training.

As I mentioned it before, one of those training sessions throughout the year is around load shed. And then the last question that was kind of revolved around the load shed subject was communications with customers. We have a predetermining documented process that we use for communication. It's a coordinated emergency plan that we have between us and PJM where our corporate communications groups talk to each other and coordinate things that will go out to the public.

And we send information out through various means: internet, popular now, social media. We actually have a group within the Company now, over the last probably three to five years, that that's kind of their sole purpose anymore is to monitor social media, provide feedback to social media, and they would also provide feedback on these issues. We also do voice and e-mail notification to -- mainly to governmental entities, usually like emergency management organizations within counties and the states, states just because it's easier to talk to those few people and e-mail those few people.

And then, finally, we also put a blast out to all of the media. We have a media organization within our company, and they communicate to all the media outlets: TV, radio throughout our service territory to get the word out when an event is going on or when we're going through this process. And it can be anything from public appeal early on to, say, can you conserve, all the way up through load shed.

And those communications, if you get to that point, would be to try to conserve as much as you can, be prepared for short-term outages, because they may occur, and also have some type of safety information in there related to whatever season you're dealing with. So if you're in the wintertime, in the case we're talking about here, we're talking about winter safety tips and things to do to protect yourself and protect your home. And the first instance, the summer, would be around summer, summer-related issues that you need to be aware of.

So that's kind of our communications process. It's documented from every level of event. So if we -- there's three stages: We have alerts, we have warnings, and we have actions. And every one of

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those has a documented flow as to what information gets sent out to customers and what media or what mechanisms we send that out, and that's all coordinated between our operations group, our corporate media group, and the PJM corporate media group.

That's all I have for that, so I'll turn it back to Jackie.

MS. VITELLO: Lastly, we have Questions 14 through 18, and these answers were provided by PJM. So Question 14 asked if the Energy Transfer Studies that FERC and NERC recommend have been conducted. The answer is no, but instead, PJM performs a Capacity Benefit Margin verification study annually to verify the CBM value of 3,500 megawatts?

The next question asked to describe the transfer capability of North Carolina's transmission system. The historical transfers are 2,500 megawatt exports, and 3,200 megawatt imports. Historical transfers are an indication of economic transfers and not emergency transfers. Although not state-to-state, PJM can calculate the aggregate capability of paths covering the PJM North Carolina interface, which is about 4,890 megawatts, both imports and exports.

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For Question 16, we described the VACAR Reserve Sharing Agreement again, but we emphasized that PJM fully covers their own reserves and does not rely on VACAR?

Finally, during the last three winter peaks, we did not experience any frequency drops below the allowable range, and this concludes our presentation. So are there any questions?

CHAIR MITCHELL: Let me check in with Commissioners to see if there are questions for Dominion. Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Good morning. Thank you for that. Very efficient, but also very quick, so my note-taking may not have been as robust as it should have been, so let me go back to some things. I'm going to start you off and then my colleagues will probably have questions, and probably we'll start in reverse order. Let's go to the end. On your slide about training and communications, and I think -- Mr. Farmer, did I get it right?

MR. BARMER: Barmer. Barmer with a B.

COMMISSIONER CLODFELTER: Barmer. Okay. Sometimes, it's hard to hear up here. So, Mr. Barmer, I take it that in your Load Shed Plan, the sequence of

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actions is, is as you list it on response to Question 13, you go first with your voluntary reductions, then you move to voltage reduction second, and then last is your involuntary load shed. That's the sequence, and that doesn't vary across the circumstances, an occasion, the need for some conservation.

MR. BARMER: No. That's --

COMMISSIONER CLODFELTER: That's the same. That's standard.

MR. BARMER: That's our standard process.

COMMISSIONER CLODFELTER: Yeah. Okay. I'm interested from a consumer standpoint. So you indicated, generally, how you provide public information of that, but let's say I'm a consumer in an event where you've decided they were coming up on an involuntary load shed or maybe even sometimes a voltage reduction, although I doubt you're going to -- going to impact the question I'm about to ask. So how do I individually learn that my 15 minutes is coming up?

MR. BARMER: That's a good question. We do not have a process in place that notifies people in advance of their 15-minute window of time. And depending on naturally -- depending on how many

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megawatts you have to shed, will determine how long between the next 15-minute window of time, but we don't currently have a process in place that notifies customers to say your 15 minutes is coming up in an hour, say. We don't have that capacity.

COMMISSIONER CLODFELTER: So if I need to take particular steps to manage devices, energy-using devices in my home, let's say I'm a residential consumer, because those are the folks that we're going to hear complaints from, okay?

MR. BARMER: Sure.

COMMISSIONER CLODFELTER: So I need to manage some devices in my home to make sure they're operating properly. I don't incur any unexpected damage from, you know, sudden on and off or a voltage change. For example, if you're in voltage reduction mode, how would I know when to institute those?

MR. BARMER: I think, though, the key thing would be when we send out notifications that say we're getting ready to go into a load shed process --

COMMISSIONER CLODFELTER: Right.

MR. BARMER: -- that you would essentially take that, at that point, and make the assumption that I can be load shed, at any point, until that is

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discontinued. Because as I mentioned, it could be, you know, depending on where you are on the list and how many megawatts that's required in each load shed, it can be anywhere from half hour to two or three hours between times that you may get that 15-minute interruption.

So if I told you the first time, then I'd have to come back at some point and tell you when the next time is. And it makes it very difficult, depending on the actual number that you're talking about, at any given time of how much you have to shed.

COMMISSIONER CLODFELTER: Does the same notification situation occur for all the class -- priority classifications or do you have different notifications to customers in, say, Class Y?

MR. BARMER: We have -- it's the same notification across the board. Now one thing I will mention is many of the customers that are those larger customers, we have a group called key accounts, and those customers are assigned key account managers, so we also communicate internally to those key account managers, and they may have internal discussions or external discussions, excuse me, with those individual customers that they handle to provide them more

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granular information. But outside of that, all the customers would get the same information.

COMMISSIONER CLODFELTER: I was going to ask you whether that holds true specifically for gas infrastructure, but that's all -- as I think -- if I heard you correctly, all of that is -- takes from transmission and is not taking off your distribution circuit.

MR. BARMER: That's correct.

COMMISSIONER CLODFELTER: So that's not subject to your Load Shed Program.

MR. BARMER: No.

COMMISSIONER CLODFELTER: So any communications that were particular to the operators of the gas pipe lines or the compressor stations, that would be handled outside your Load Shed Program.

MR. BARMER: And those -- yes. Even though they wouldn't be in our Load Shed Program, those customers are in that key account group, so they would have a manager --

COMMISSIONER CLODFELTER: They would have a manager.

MR. BARMER: -- assigned to them, and he would get the information. Even though they aren't

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part of that actual load shed process, they would contact them just to let them know the condition we're in. I don't think the -- the gas pipeline folks probably wouldn't change what they're doing a whole lot.

There may be other key accounts, other large customers who may be able to reduce their usage during that period and help the situation, and that's one of the appeals that we also use through that key account process, is to have those key account folks talk to all their accounts to see if anybody can reduce some -- anything. Every little bit helps, so they do that.

COMMISSIONER CLODFELTER: By the way, let me ask while I'm on it. The priority, circuit priority codes --

MR. BARMER: Yes.

COMMISSIONER CLODFELTER: -- what's the sequence? Is Z the highest or the lowest?

MR. BARMER: Z is the -- Z are the ones that are excluded, so --

COMMISSIONER CLODFELTER: So of W, X, and Y, which is highest priority?

MR. BARMER: Those are -- W, X, Y, Z, are

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the ones that are actually in the Shed program, and they start with the X, they go -- I mean the W, the X, and the Y, in that order.

COMMISSIONER CLODFELTER: So W is highest priority?

MR. BARMER: W is lowest priority in terms of shed.

COMMISSIONER CLODFELTER: Okay.

MR. BARMER: In terms of --

COMMISSIONER CLODFELTER: That's what I was really getting at. It's a reverse the sequence of letters in order to get my priority.

MR. BARMER: Yes.

COMMISSIONER CLODFELTER: Okay. Got it. Back to the communications, you indicated in your presentation that you do give in your communications some information, safety information?

MR. BARMER: Yes.

COMMISSIONER CLODFELTER: So I'm really curious about that. And, by the way, listen up Duke. Most of these questions I'm going to ask -- Mr. Roberts, you're probably going to get -- you're going to get these questions too. So what kinds of safety information are you communicating? Is it just

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sort of like risk type information or do you also communicate to the customer how to manage their use and consumption as well? Is that part of the safety communications?

MR. BARMER: Part of it is, yes, things you can do to reduce your usage, naturally, but the safety component is more about -- so if it's a winter situation, it may be -- you may have a situation where an item in there talks about generator safety.

If you have your own generator, you know, how you don't hook it up in the garage, be sure that you're keeping your house closed up as much as possible. Don't be opening doors, you know, and letting cold air come in during the period because you're going to lose heat. Just a variety of those kind of things, just so people know.

You know, most people know these things, but, you know, you may have kids and people are just like roaming in and outside of the house, and they just don't -- they're not thinking consciously because you need to have a different focus when you're in a situation where the power may go out multiple times, over a period of time.

COMMISSIONER CLODFELTER: You and I may know

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these things. You may know those things, but I don't assume that everyone does, and that's why I'm asking the question about them. Duke provided us with their materials, some examples of their communications to customers. Do you have examples, templates that you could share with us? Is that possible?

MR. BARMER: We can get some.

COMMISSIONER CLODFELTER: I'm particularly interested in this topic of what you can communicate to customers about how they should manage things on their end. And I'll say to Duke, your materials did not include that topic, so I'm going to ask you if you got materials on that topic as well. But if you've got examples of communications that'll be useful to see.

MR. BARMER: Okay.

COMMISSIONER CLODFELTER: I'm going to back up to -- do you have the slides in front of you?

MR. BARMER: I do, yes.

COMMISSIONER CLODFELTER: You do. I can't remember which questions they correlate to, but I can refer you to the right slide for my question. So I'm looking now at slide 7. This may be an -- I suspect it's an operational question, so I'm not sure I fully

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understand what you're telling me at the very last bullet point there or the arrow there. 34 of 122 circuits are included in the Load Shed Plan. Let me stop with that. So does that mean the other circuits are --

MR. BARMER: Not -- they're excluded.

COMMISSIONER CLODFELTER: Because? Because.

MR. BARMER: Either they are critical customers or in this case, the reason it's much lower is because there's many of those circuits have distributed generation on them, so we don't want to shed distributed -- a net positive generation.

COMMISSIONER CLODFELTER: Right.

MR. BARMER: So we don't want to shed those circuits because it defeats the purpose of --

COMMISSIONER CLODFELTER: Okay. So the difference there between the 34 and 122 is composed of critical accounts or critical infrastructure?

MR. BARMER: Right.

COMMISSIONER CLODFELTER: And the net positive circuits. So let me ask -- yeah. Sorry.

MR. BARMER: I wanted to put that on here because that is a little unique to North Carolina or North Carolina area. We're starting to see it more in

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Virginia. But because of the net penetration of Solar in the State of North Carolina, we see that trend more here than across our footprint.

COMMISSIONER CLODFELTER: All right. I -- that's the next question. I want to ask about that item on the slide. And I may not get the question framed very well, so you and Mr. Dibble -- is it right?

MR. DIBBLE: That's correct, yes.

COMMISSIONER CLODFELTER: Okay. Got it. Again, the pronunciation is quick and sometimes hard for me to write down. The two of you may need to figure out how to get my question framed the right way in order to answer it.

So I'm in a situation in January and I get an ice storm in eastern North Carolina in your territory. It hits your territory pretty hard, and so you tell me that a lot of the circuits in that territory are net positive because of distributed generation, but it's an overcast day for three days because for crying out loud, we're having an ice storm. You're not getting any generation off of those circuits, so how do you operate - in terms of your Load Shed Program, how does it work in that

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environment?

MR. BARMER: Well, first off, when we say our Load Shed Program, when I'm talking about that program itself, it is a predetermined load shed software event, so everything is predetermined in there. And all we do -- all our operators have to do is once we are in conjunction with PJM, say there's a directive to shed 200 megawatts -- let's use a number -- all we have to do at that point in the program, the operator plugs in 200 megawatts. It goes down and sheds all the circuits to get that 200 megawatts gone, so that's all pre-programmed, pre-established in the program itself.

Now, if we get to a situation where that doesn't fix what we need fixed, we always have the capability to trip circuits manually, if we needed to, hopefully wouldn't move to that point, but that's outside of our established load shed program itself, but we can always -- if we get into a bind in a specific area that we needed to shed load for some specific reason, outside of a system need, we have the capability to do that.

COMMISSIONER CLODFELTER: Yeah. Thank you. That's helpful. That is helpful. I may not be asking

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a good question, and I guess what I'm trying to get at, does it mean that these circuits, that we have net positive distributed generation, are essentially treated the same as critical infrastructure circuits? They're exempt? They don't ever -- are they not as subjected to the Load Shed Program?

MR. BARMER: Currently. That's correct.

COMMISSIONER CLODFELTER: So if I happen to live -- a residential customer living and connecting to one of those distribution circuits, that's good for me.

MR. BARMER: Definitely.

COMMISSIONER CLODFELTER: Got it.

MR. BARMER: It's like I always equate it to you want to be on a circuit that's very reliable, be on one close to a hospital.

COMMISSIONER CLODFELTER: I am. I'm a Duke customer, but I'm within a block of a hospital. You're right. I appreciate the advantage. But in effect, a lot of the customers in northeastern North Carolina are similarly situated. That's what you're telling me. That helps me. Thank you. Thank you. I'm going to move back -- I'm moving backwards, so Ms. Vitello --

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MS. VITELLO: Yes.
COMMISSIONER CLODFELTER: -- I got it right?
MS. VITELLO: That's right.
COMMISSIONER CLODFELTER: Got it. Okay. So I'm on slide 5 now. I've got several questions there. You've got about plus or minus 9,500 megawatts of natural gas capacity in the Dominion fleet and about a little more than a half of that is dual fuel capability. Is there any -- I missed a question, but let me go ahead and finish this one first. Is there any sort of movement to sort of expand the dual fuel capability on the remaining units?
MS. VITELLO: Yes. So that's part of our biggest risk, is the large combined cycle units that are only natural gas right now, so there are discussions about how can we make it a dual fuel unit in some way.
COMMISSIONER CLODFELTER: Are all of your quickstart units that you rely on for quickstart capability, are those all dual fuel?
MS. VITELLO: Yes.
COMMISSIONER CLODFELTER: They all are?
MS. VITELLO: They all are.
COMMISSIONER CLODFELTER: Do you have a

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standard technology configuration for a quickstart unit? Is it an industrial frame CT? Is it an aero derivative CT? Is it a RICE unit, is it something else? I mean, do you have a standard quick start configuration that you prefer?

MS. VITELLO: Chris.

MR. DIBBLE: No, sir, there's no standard. It's a broad range of technologies over the years, so...

COMMISSIONER CLODFELTER: Do you have a -- just describing your fleet, when you look at those units that you would call on first for quickstart capability, what's the predominant type of unit that you're using?

MR. DIBBLE: The GE 70. It's an oil operated combustion turbine.

COMMISSIONER CLODFELTER: Okay. But it's an industrial frame type of technology?

MR. DIBBLE: It is. That's correct.

COMMISSIONER CLODFELTER: Okay. And do you have any other alternative technologies, aero derivatives or --

MR. DIBBLE: No.

COMMISSIONER CLODFELTER: You do not, not

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currently?

MR. DIBBLE: Not currently, no, sir.

COMMISSIONER CLODFELTER: Okay. You have a question that was not in the presentation materials I just want to ask about. On page 8 of the written filing, the Company listed four scenarios under which your gas fire units might be subject to upstream curtailment because of upstream problems, and I'm not going to read them there. You have them in your file, and we all have them.

I'm just a little bit curious to find out have you experienced any of those upstream curtailment considerations that have affected your performance in extreme weather events, historically?

MS. VITELLO: Not during extreme weather events. So, like, I'll point out the number 3 on this page, page 8.

COMMISSIONER CLODFELTER: Right.

MS. VITELLO: So, for example, if you buy min load gas and you pass that nomination cycle, and you plan on sitting at min load the whole time, that's fine. But if PJM calls you up to full load, you might not have that gas available.

COMMISSIONER CLODFELTER: Right.

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MS. VITELLO: Now, the gas day is 10 a.m. to 10 a.m., so you are able to burn your -- you know, you can average your full 24 hours to meet your burn, if you need to.

COMMISSIONER CLODFELTER: You have experienced that historically?

MS. VITELLO: So in winter peak events, we have not because in a winter peak event, we will most likely be buying all the gas that we can --

COMMISSIONER CLODFELTER: Okay.

MS. VITELLO: -- up to full load of all of our gas units, so not during a winter peak event we haven't experience any of these.

COMMISSIONER CLODFELTER: Okay.

CHAIR MITCHELL: So I just want to follow up on what you just said, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Sure.

CHAIR MITCHELL: So the Company has never experienced an event -- an instance where it's never been able to purchase the maximum amount of gas it needs?

MS. VITELLO: That's right.

CHAIR MITCHELL: Okay.

MS. VITELLO: So if we haven't, then --

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like, for example, a Possum Point 6 or a Bear Garden, maybe it might be more of a cost situation where we decide to switch those units to oil, but we haven't had a situation where they said there's no gas.

CHAIR MITCHELL: There's no physical limitation.

MS. VITELLO: That's right.

CHAIR MITCHELL: Okay.

COMMISSIONER CLODFELTER: Good opportunity for me to backtrack and catch a question I meant to ask earlier and didn't. Back to you, Mr. Barmer. Since the events at ERCOT in the winter of last year, have you made any changes in the Load Shed Program that you've described to us specifically in response to that event. And, if so, what changes did you make?

MR. BARMER: Not really. We did reach out to the gas providers because that was an issue in that event. And just to see if there were any locations that we did not have identified already, and there was nothing different that we were able to find.

COMMISSIONER CLODFELTER: Okay.

MR. BARMER: That was probably the biggest thing we did as a result of that in terms of the Load Shed Program. No changes.

COMMISSIONER CLODFELTER: Thank you. Thanks for letting me backtrack a little bit. I'm looking at your slide number 4. And it's a question, really, just a curiosity question, is how closely do your internal forecast and what you get from PJM, how closely do they track? Do you ever see any divergence, especially as they may relate to the Dominion operating zone or territory?

MS. VITELLO: Yes. So we have the two external load forecasts and we have PJM's load forecast, and we have our own internal load forecast.

COMMISSIONER CLODFELTER: Right.

MS. VITELLO: And periodically, we'll go through reviews to see which forecast is doing better, and we'll weight them based on which one we see is lining up closely. So, overall, like, you could expect 3 to 5 percent if you're going to compare the PJM load forecast to our internal forecast, but they all vary just based on the seasons and time.

COMMISSIONER CLODFELTER: That's a range of variation, 3 percent up and 3 percent down or just 3 percent across the average? Which?

MS. VITELLO: Across the average.

COMMISSIONER CLODFELTER: It's up and

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down --

MS. VITELLO: Up or down, yeah.

COMMISSIONER CLODFELTER: Up or down one and a half percent each way?

MS. VITELLO: Yes.

COMMISSIONER CLODFELTER: Okay. And so that's not really -- you haven't seen anything more significant of that in terms of your forecast?

MS. VITELLO: No. But if you're only looking at the peak events --

COMMISSIONER CLODFELTER: Right.

MS. VITELLO: -- so, like, these, it's within .7 percent, so that's much better than the average.

COMMISSIONER CLODFELTER: It's even closer?

MS. VITELLO: Yeah. Right. But if you look at the whole spring, fall, summer, winter, you're going to be between 3 percent.

COMMISSIONER CLODFELTER: I'm interested in your written materials. And, again, you covered it in your presentation. There was a significant improvement in outage performance between 2014 and 2018 events, and you attribute that in the written materials to PJM's 2016 emergent -- the capacity

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performance.

MS. VITELLO: That's right.

COMMISSIONER CLODFELTER: I'm sort of curious. It is significant when I look at the data. It's a significant improvement.

MS. VITELLO: Yes.

COMMISSIONER CLODFELTER: And so I'm curious of what steps, specifically, did you take and did other utilities take in response to that initiative by PJM.

MS. VITELLO: So in terms of the --

COMMISSIONER CLODFELTER: What was the thing that produced the change?

MS. VITELLO: Yeah. So in 2014, if you had a one-day forced outage, it would just affect your E-40, right? It wasn't going to affect anything else, so maybe people didn't buy that expensive gas and they said I'll just take the forced outage instead. So now looking past 2016, when you get to the cold snap of 2018, if you just want to take your forced outage for that one day, you are also going to potentially have this $3,600 per megawatt hour penalty on top of it, which nobody wants that penalty. So people bought the expensive gas and ran those units to avoid the

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penalties.

COMMISSIONER CLODFELTER: So that was enough of an incentive to simply make you change the --

COMMISSIONER CLODFELTER: And winterize your equipment and make other changes to your actual --

COMMISSIONER CLODFELTER: It wasn't any one single thing. It was across the board, sort of?

MS. VITELLO: Probably. Right.

COMMISSIONER CLODFELTER: Okay. Okay. Let me ask you a question that is not in -- perhaps it should have been in the written materials. And I apologize that it wasn't, so it's going to hit you a little bit cold.

MS. VITELLO: Okay.

COMMISSIONER CLODFELTER: But, again, Duke, listen up. I'm going to ask you the same questions. So, you know, there are a number of different used cases that have been talked about for storage solutions, especially battery storage now.

MS. VITELLO: Yeah.

COMMISSIONER CLODFELTER: But also including traditional, you know, hydro storage or pump storage, or for microgrids as potential solutions for a normal grid operations situation. Have you really explored

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how you might deploy those solutions in the emergency context? And so talk about where you are and what your thinking is, and what your planning might look like about what you do to make the used case for battery storage or for microgrids in the extreme weather event or the extreme weather event of any kind. Yeah.

MS. VITELLO: So, you know, we've had Bath County pump storage for a long time now.

COMMISSIONER CLODFELTER: Right.

MS. VITELLO: So we're used to Bath County. The new technology would be the battery storage, which we're just now starting to get into our fleet. So, right now, I mean, we've looked into external models that'll help us predict when we need to be pumping and when we need to be generating. Regulation is a big part of battery storage.

COMMISSIONER CLODFELTER: Right.

MS. VITELLO: And so particular to emergency events, I don't think that we've gone that far on the battery storage yet.

COMMISSIONER CLODFELTER: I'm curious about that because, again, the way you operationally manage storage, battery storage resource would be very

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different if you're using it for ancillary services or to sort of change your profile, your load profile.

MS. VITELLO: That's right.

COMMISSIONER CLODFELTER: And the way you would use it operationally, if you're going to use it as a backup resource or a quickstart resource or an emergency resource, in an emergency situation.

MS. VITELLO: Right.

COMMISSIONER CLODFELTER: So I'm a little interested in just hearing you talk about how you're exploring that topic.

MS. VITELLO: Right. Yeah. So, I mean, your battery storage, you can definitely -- like for Bath County, for example, if we see cold weather coming up, then you might run less in the days before that event just to fill up your pond so you're ready for the cold weather. So it would be things like making sure everything's full. Do you have anything to add?

MR. DIBBLE: No.

COMMISSIONER CLODFELTER: I didn't expect to really detail the answer right now because I think it's an emerging -- it's an emerging topic. But, again, I wanted to ask about it just to sort of --

MS. VITELLO: You're thinking about it.

COMMISSIONER CLODFELTER: We're thinking about it and we're just interested in learning from you what you're learning about it, what you're thinking about it.

MS. VITELLO: Right. Right. And if you're regulating the unit, you're not regulating all 24 hours, you know. You can regulate some hours and be part of the energy market for some hours. You don't have to be only regulating.

COMMISSIONER CLODFELTER: Let me take just a minute to see if I have anything else, and then I will turn it over to my other colleagues I think that's probably it for me.

CHAIR MITCHELL: Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: I'll come back.

CHAIR MITCHELL: Commissioner McKissick.

COMMISSIONER McKISSICK: Just a couple questions. You spoke of the dual fuel capacity, those facilities. The thing that you did not identify was what type of oil reserves you actually have on hand. So can you --

MS. VITELLO: So that's on the slide right here, so the days at full load, if you can see that.

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And those are full load 24 our days. So, for example, Bear Garden has 5.2 days at full load. And, generally, when you're running on oil, one of the benefits is that you don't have to run for 24 hours, 48 hours.

You can run for a four-hour period and shut back down. So if you're running on oil, we'll usually cycle those units more often. So that 5.2 days is actually -- you know, if you run it four hours each day, it's more like 20 days, but -- so you can see that on the slide here.

COMMISSIONER McKISSICK: And you keep that oil available on reserve. I mean, it's not like you're --

MS. VITELLO: That's right.

COMMISSIONER McKISSICK: Depending upon --

MS. VITELLO: It's on site, yeah. We fill the tanks to 95 percent just for movement.

COMMISSIONER McKISSICK: Got it. Got it. And just another question that came to my mind. In terms of the -- put it the way you've identified the load shed priorities, once the customer has identified in a certain category, how often do they fall out of one category or into another? I mean, how often is that re-evaluated?

MR. BARMER: We rely on the customers to keep us updated on the criticality or the change of their importance, if you will. So we don't have a regular set time we go back and update it, but we do rely on customers to provide that information to us. Now, we do reach out, and it was one of the questions in here for the water treatment.

We reach out to governmental entities annually for them to review and update their information. Really, the reason -- the biggest reason for that is usually, the governmental entities have a lot of different accounts; everything from fire and rescue to water treatment. So there's a lot of different departments there, so it's easy for some of those to get dropped or changes to be made. So we send something out to them on a regular basis just to provide us feedback on any changes, but we don't do that for all customers.

COMMISSIONER McKISSICK: Okay. And is there a reason why you don't go back to other categories of customers to try to see if it's appropriate to remain in the category? I mean, I can see why the governmental entities would want to check it.

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MR. BARMER: I would say the biggest reason is very few changes that take place once an account's established, if it's a critical account or something generally doesn't change. It could but, you know, it's not -- even the existing accounts we look at year over year, the existing account. Now, when new accounts come in, we have to evaluate those and see where they fit into this matrix. But for existing accounts, we don't see a lot of changes from year-to-year, even from the governmental ones, because once they're kind of established, there's not a lot that really changes on those accounts.

COMMISSIONER McKISSICK: So with the governmental entities, you send out a request to ask them to re-evaluate it, and then they supplement it --

MR. BARMER: Exactly.

COMMISSIONER McKISSICK: -- and see if it remains the same or --

MR. BARMER: Exactly. Can you verify -- you know, can you go in and verify any changes or updates that are needed for the accounts. And what they -- I'm not going to say all of them do it, but look at the existing critical type accounts you have. But also any other accounts to be sure that there's none

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that need to be in those categories that you haven't identified already.

We've been doing it for many years now. It was mainly for the prioritization for big restoration events so that we got critical infrastructure back on quicker. So we've been going through this process pretty heavily and over many years. And so once we see these accounts that are set up there again, we don't see a whole lot of changes once they're initially set up on the type situation.

COMMISSIONER McKISSICK: Got it. And in terms of those customers that are not subject to Curtailment, give me an example of what types of customers would fall into that category.

MR. BARMER: It could be a large military installation or a critical -- call it federal installation. We serve a lot of those in our territory. It could be a -- in some cases, we have large hospitals that the whole hospital is not necessarily on backup, but the critical care components of the hospital are on backup. But it's such a large facility that, you know, you don't want to -- would not want a several-hundred bed hospital being taken offline, even though they have backup for

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the critical and emergency, and surgical wings, and things like that. So those are kind of the examples, I would say, that are excluded.

COMMISSIONER McKISSICK: Sure. And I know you stated earlier what Dominion has done overall, but are there things outside of the North Carolina territory in terms of changes that might have been made in light of the situation in Texas, other than -- anything whatsoever in terms of changes, strategies, policies, perspectives about dealing with the type of crisis they experienced, or your comments -- I guess I'm trying to determine if there are things that are outside of what we've discussed today or you presented information about today that might be more generically applicable that have been things you've undertaken?

MR. DIBBLE: No, I don't believe so.

COMMISSIONER McKISSICK: You don't believe so? Okay.

MR. DIBBLE: However, from an operations perspective, we have a pretty robust plan in place, and it's a little different climate in Virginia. We expect there to be sustained periods of freezing for longer periods of time, so our infrastructure and our procedures are built to withstand that, so it's a little different situation. So, generally, not a lot of lessons learned other than the awareness of -- that we can't allow that to happen to others.

COMMISSIONER McKISSICK: And I guess my last question would simply be if you could sit back today and think about measures that could be taken that would improve reliability, decrease the probability there'd be interruptions of service, what would they be?

MS. VITELLO: Fuel on the ground which we have at most of our sites.

COMMISSIONER McKISSICK: That would be it. So you feel pretty comfortable overall?

MS. VITELLO: Yes.

COMMISSIONER McKISSICK: Nothing that would be additional that you'd consider doing?

MS. VITELLO: No.

COMMISSIONER McKISSICK: Thank you. I don't have any further questions.

CHAIR MITCHELL: Commissioner Duffley.

COMMISSIONER DUFFLEY: Good morning. This is for Mr. Barmer. I heard you state that the last load shed was in 1994. But if you can go to slide 8, you talk about voluntary reductions and voltage

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reductions. What's the frequency that you implement those two activities?

MR. BARMER: That's actually a good question. I don't have the frequency, but we have implemented voltage reduction several times since that majority of the time, voltage reductions are very, I would say, almost invisible to customers. They don't really see that impact on their operations. The voluntary, we don't -- probably along the same lines, we've probably done it maybe -- and this is estimating. Since '94, we may have done 10 times total, both of those combined, voluntary and voltage reductions.

COMMISSIONER DUFFLEY: Okay. Thank you.

MR. BARMER: And it's usually -- in some cases, it's been more localized, so maybe one part of our area has some issues and we had a voltage reduction, but not a system-wide type thing.

COMMISSIONER DUFFLEY: Okay. Thank you. That's all my question.

CHAIR MITCHELL: And I want to follow up with you there before I turn to Commissioner Brown-Bland. To what extent -- I mean, is PJM calling it voltage reduction or does Dominion call it the

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voltage reduction?

MR. BARMER: PJM.

CHAIR MITCHELL: Okay.

MR. BARMER: They provide directives to us because they're a transmission operator.

CHAIR MITCHELL: All right. Thank you. Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: Yes. I have a couple questions. One, I wanted to follow up on the Curtailment question with regard to the gas plants that are subject to Curtailment during the winter or the cold, extreme weather. And so as you discussed with Commissioner Clodfelter, there were the four scenarios that you put forth.

With regard to those, and I heard that one when you followed up with Chair Mitchell, that you hadn't ever even had to -- you hadn't fallen into either one of those. But beyond that, do you have any idea of how you write the likelihood of needing -- you know, of those occurring?

MS. VITELLO: I wouldn't know the likelihood, no.

COMMISSIONER BROWN-BLAND: It's obviously pretty low, but I didn't know like if you internally

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ranked them or had some idea beyond that.

MS. VITELLO: So ranking of these four listed on the page, 1 and 2 would be last, because that would be a force majeure event on the pipeline. So 3 and 4 would be a higher rank, if you want to rank them, just because what if we don't buy that gas or what if we don't schedule it by twenty-hundred that night? Then you have until 10:00 a.m. the next day, and you might burn more or less than what you are expecting.

COMMISSIONER BROWN-BLAND: Okay.

MS. VITELLO: So this Operational Flow Order, which we call OFOs, that's a penalty if you overburn or underburn, depending on what the OFO says. So it's a financial penalty, so I would say the order would be 3, 4, and then 1 and 2 to rank them.

COMMISSIONER BROWN-BLAND: Thank you. And then the last question is with regard to Dominion's supply sources. Within your supply program, are there sources that you consider to be more or less risky, and could you talk us through that?

MS. VITELLO: So nuclear, obviously, is the least risky, base load units. Is that what you're asking, like, what type of fuel sources and how we're

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seen there?

COMMISSIONER BROWN-BLAND: And with regard to your gas supply.

MS. VITELLO: With regard to gas supply. So --

COMMISSIONER BROWN-BLAND: Sources from which you procure your gas.

MS. VITELLO: Right. So Possum Point 6 would probably be the riskiest of the gas units, but it's also dual fuel. So if we didn't get the gas, we'd switch to oil. Brunswick, Greensville, Bear Garden, they're all on Transco. So if I purchased too much at Greensville, I could switch it to Brunswick or Bear or any other unit that runs on Transco. So like my four Remington units that are quickstart CT's, say I had a Brunswick unit trip and I needed to burn the gas somewhere, I would bring on my four Remington units.

Warren County, they have multiple sources of pipelines that they could use, so I would say that's less risky. Yorktown 3, for example, it's really hard to get gas there, but they also can start up on oil, so...

COMMISSIONER BROWN-BLAND: And with regard

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to the suppliers from where you get that gas, I hear the different pipelines, but beyond what you've told me, is there any other consideration for having a more -- a firmer source versus you ranked them at a risk?

MS. VITELLO: No.

COMMISSIONER BROWN-BLAND: All right. Thank you.

MS. VITELLO: You're welcome.

CHAIR MITCHELL: Commissioner Hughes.

COMMISSIONER HUGHES: Yeah. I'm just very curious about the trends of self-supply and backup. You say you've been following that and tracking that. Could you just say some comments about the trends? Is it something that, you know, after every -- not curtailment because you don't have those, but after every storm, you know, people flood the generator, you know, the generator stores and buying. Have you been tracking it? Is that anything anybody has ever done on a residential side to kind of know if that's how fast it's growing through a surveyor or something? But I'm more interested in your large customers. Is it getting to be unusual for someone not to have backup these days or is it --

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MR. BARMER: Yeah. It varies by type of customer, I would say, and it kind of follows similar to what you said. Sometimes, it follows events. I know, as an example, for us, our big event was Hurricane Isabel back in 2003.

And immediately after that, Food Lions everywhere were putting in generators, because, you know, they went long periods of time without power. So I think it's probably more specific to whatever that customers' needs are. We do see -- I'm not going to say the trend is way up, but we do see that trend going up some in certain categories.

COMMISSIONER HUGHES: I'm just curious. Thank you.

CHAIR MITCHELL: Commissioner Gray.

COMMISSIONER GRAY: So I gave up my landline a few years ago. I only worked with them with this one. The power goes out on slide 8, you show communication opportunities, all of which depend on public media. Oh, by the way, I only have a Dish. I don't have local Spectrum or Comcast. So how am I going to get to know this?

MR. BARMER: That's a good question.

COMMISSIONER GRAY: I'm getting ready to

retire, so I need to know.

MR. BARMER: I mean, I think we hit many of the actual media type outlets and communications outlets. But I will say as a company, we're always looking to further our methods of communicating with customers. And one of the things that we're trying to do is get more towards where -- the question, kind of, revolved around the original question that Commissioner Clodfelter brought up about how do we communicate when that outage is going to occur, because that is kind of an event.

We would like to get to the point where we can set something up and say hey, customer, you're going to go out in 15 minutes, but it's got to be to a medium that customer necessarily uses. And we are pushing more of our communications cellular mediums, either through texting or I would call it advanced, kind of like a voice response, kind of a pushed message out to folks, but we're not to that point quite yet.

COMMISSIONER GRAY: Yes, because the cell tower needs power as well.

MR. BARMER: And that's an internal problem that we are currently dealing with as well because we

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use a lot of cell communications internally, and keeping that communications network up is critical to us being able to do our job as well.

COMMISSIONER GRAY: Urgent to take a look at it.

MR. BARMER: Yes.

CHAIR MITCHELL: Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: I had one more. With regard to the load shed question that you discussed with Commissioner Clodfelter regarding -- you said circuits were not a part of the Load Shed Program because they had positive generation.

MR. BARMER: Correct.

COMMISSIONER BROWN-BLAND: Do you know, at any point in time, which circuits is Dominion capable of knowing and which circuits have that net positive due to distribute generation?

MR. BARMER: Yes, we do. We have digital communications to all of our substations, so we know when the flow is positive or negative.

COMMISSIONER BROWN-BLAND: So, at all times, you're able to assess?

MR. BARMER: Yes.

COMMISSIONER BROWN-BLAND: All right. Thank

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you.

COMMISSIONER CLODFELTER: Well, let me follow up on that because as I understood it, the structure of your program is that if you are net positive on some periodic basis, you're outside the program.

MR. BARMER: That's correct.

COMMISSIONER CLODFELTER: Even if on the given day of that event, there's no positive flow off of that circuit.

MR. BARMER: That's correct.

COMMISSIONER CLODFELTER: You're still exempt.

MR. BARMER: Yes.

COMMISSIONER CLODFELTER: Okay. I want to be sure I understood it correctly.

MR. BARMER: Yeah. We can still see that. We can still see what it is realtime, but in the program itself.

COMMISSIONER CLODFELTER: Right.

CHAIR MITCHELL: Just a few questions for y'all. Mostly follow-up on comments already made, but I want to talk for a minute about OFO's during extreme weather. Just educate me a little bit. Are OFO's

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common during extremely cold weather?

MS. VITELLO: Yes, very common. Yeah. It's a -- the pipeline will call the OFO and they'll say don't be short or don't be long.

CHAIR MITCHELL: So that's just a common operational --

MS. VITELLO: Yeah. During even non-extreme weather events, we have OFOs, and they'll say -- and they'll give a percentage too. So they'll say, don't be long by 5 percent, or don't be short by 2 percent, even.

CHAIR MITCHELL: So the Company is accustomed to operating subject to OFOs?

MS. VITELLO: Very comfortable.

CHAIR MITCHELL: Has it posed a -- a serious -- I mean help me understand. I can understand that it would be challenging to operate under an OFO, but problems?

MS. VITELLO: No problems. You know, if we trip a unit and it says don't be short of gas, then they have to scramble to figure out how to get rid of the gas, but they're so common that we're used to running with the OFOs.

CHAIR MITCHELL: Okay. Increasingly common?

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MS. VITELLO: Yes.

CHAIR MITCHELL: Okay. The fuel oil, again, this is just education for me. How often do you-all go into a situation where you have to burn fuel oil?

MS. VITELLO: So if PJM dispatches a unit and we've offered it on oil, we will check to see if there's gas. And if there's not, then we'll run it on oil, or check to see if we want to buy the gas. In the wintertime, it's usually an economic decision where oil is equivalent to 15 or $20 gas. So if gas prices go to 30, we will economically make the choice to run on oil.

CHAIR MITCHELL: Okay.

MS. VITELLO: It's usually not a -- we don't have the gas. It's more of an economic decision.

CHAIR MITCHELL: And so do I understand correctly, then, that the Company will burn oil at times other than extreme situations when there is a shortage of gas?

MS. VITELLO: That's correct.

CHAIR MITCHELL: It's an economic -- it could be an economic decision.

MS. VITELLO: That's correct, yes.

CHAIR MITCHELL: And so do I also

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understand, then, that you're sort of continually cycling through oil supply so that you never have a situation where the oil is just sitting there on site?

MS. VITELLO: That's right. So we -- yes. We try to run oil at least once a year, make sure it can run, and then we're cycling through the oil and the demon water. Demon water's a big thing when we run on oil. We'll run out of demon water before we run out of oil.

CHAIR MITCHELL: Okay. The Company's response to Question Number 10, critical natural gas infrastructure cites and load shedding programs, I understand the Company's response there, but can you help me understand what type of critical natural gas infrastructure is tied to your transmission? What kind of equipment are we talk about?

MR. BARMER: Natural gas compressor stations.

CHAIR MITCHELL: Compressors?

MR. BARMER: Yes. And one thing that we have talked to those companies as well, some companies, some natural gas companies, their compressors are gas-powered, so it's like, you know, powered from their own source. But there are some that are electric. The ones that we were referring to here are the ones that have electric servers that has a compressor station.

CHAIR MITCHELL: And are you aware -- are those located in North Carolina?

MR. BARMER: No, they're not.

CHAIR MITCHELL: All of them are in Virginia or --

MR. BARMER: Yes.

CHAIR MITCHELL: -- elsewhere. Okay. I have a follow-up on the VACAR question. So the Company's response to question number 15 was given prior to the Commission's becoming aware that Dominion intends to withdraw from the VACAR reserve sharing arrangement. Does the Company's response to question 15 change in light of this development?

MS. VITELLO: So number 15 -- so question 16.

CHAIR MITCHELL: Was it 16?

MS. VITELLO: So our --

CHAIR MITCHELL: Okay, sorry, 16. And then I'm going to ask you about 15. So yes. Does the answer to 16 change?

MS. VITELLO: I would say the answer would

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not change, only because Dominion is part of this VACAR reserve sharing agreement. They haven't used it in the last 10 years. Nothing with the reliability would change as we still have reserve requirements in PJM.

CHAIR MITCHELL: So when you say, "they haven't used it," you mean Dominion hasn't relied on it because Dominion is part of PJM?

MS. VITELLO: PJM has not relied on it.

CHAIR MITCHELL: Okay. PJM hasn't called on the other VACAR members.

MS. VITELLO: That's right.

CHAIR MITCHELL: All right. Transmission capacity and the VACAR situation. So does -- let me get to my questions here. Will Dominion and PJM, to the extent that you can answer on PJM's behalf, have to change its transmission capacity available to the North Carolina -- to the PJM North Carolina interface as a result of this change, and as a result of Dominion's pulling out of VACAR?

MS. VITELLO: I do not think so. Do we want PJM to verify that?

CHAIR MITCHELL: Yes. And then I want to ask you -- so, yes, I want PJM to verify that, and

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PJM, y'all can come on up. What about the emergency situation, because the Company's response indicates that additional transmission capacity could be available under emergency situations.

MS. VITELLO: The fourth -- right.

CHAIR MITCHELL: Does Dominion's withdrawal from VACAR implicate what might be available on an emergency basis? Is that also a PJM?

MS. VITELLO: Yeah, that's a PJM.

THE COURT: Just for the record, gentlemen, would y'all introduce yourselves, please.

MR. BIELAK: Yes. I'm Donnie Bielak, Senior Manager of dispatch for PJM Interconnection.

MR. LAROQUE: Matt LaRoque, Senior Manager of Regulatory for PJM. North Carolina's one of the my states.

CHAIR MITCHELL: Good morning, gentlemen. Did you-all hear my question to Dominion?

MR. BIELAK: I heard the first question. I was walking up during the second question.

CHAIR MITCHELL: So, in general, help us understand -- the information that Dominion provided to us in response to questions number 15 and 16 was provided prior to the Commission's becoming aware that

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Dominion intends to withdraw from VACAR. So with respect to transmission capacity available at the North Carolina interface, does Dominion's withdrawal from the arrangement change that transmission capacity that's available?

MR. BIELAK: The withdrawal of Dominion from the VACAR reserve sharing group does not change any of the transmission capability between either Virginia, North Carolina or the greater PJM control area in the Carolina region, and all of our existing capabilities to transfer energy, both north to south and south to north remain status quo.

CHAIR MITCHELL: Okay, perfect. You answered that question. And so -- help me, just confirm for me that it would be all the same for emergency situations, that there's not going to be a reduction in transmission capacity available under emergency situations, as a result of Dominion's withdrawal from VACAR.

MR. BIELAK: Correct. There are no changes as far as transmission capability under emergency conditions either.

CHAIR MITCHELL: Okay. Thank you. Let me just look back through my notes. Commissioner

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Duffley.

COMMISSIONER DUFFLEY: I have a follow-up about your comment about the economic decision to burn fuel oil versus natural gas. Can you remind me. Are there environmental restrictions on how long you can run that fuel oil?

MS. VITELLO: Yes.

COMMISSIONER DUFFLEY: Can you remind me what those are?

MS. VITELLO: So it depends on the station, but there are environmental conditions when we do run oil. So we also take that into consideration when we dispatch oil.

COMMISSIONER DUFFLEY: But, I mean, can you just give me a general range of length of time you're able to burn the fuel oil?

MS. VITELLO: Generally --

COMMISSIONER DUFFLEY: It's okay.

MR. DIBBLE: It depends on the station. Y'all have different permits.

COMMISSIONER DUFFLEY: Okay.

MR. DIBBLE: So it's typically -- if you're going to run the oil for more than a few days, you're kind of hitting your limit on the CTs, on the large,

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heavy oil units, so it's obvious they can run in a base load condition, but the small CTs those are typically -- after a couple of days, you're getting pretty close if not exhausting your emissions.

COMMISSIONER DUFFLEY: And during an emergency event, how likely is it that EPA would give exemptions on those permits?

MR. DIBBLE: I'd rather not speak for the EPA, but none of our procedures or processes involve us wilfully violating the permit to meet a blackout condition. We'll figure out a way to not do that and -- to not violate the permit and work through that situation.

COMMISSIONER DUFFLEY: Okay. Thank you.

MR. DIBBLE: You're welcome.

COMMISSIONER CLODFELTER: Do your permit conditions include options for variations in the emission limits based upon emergency weather conditions?

MR. DIBBLE: For the what?

COMMISSIONER CLODFELTER: Is that built into your permit?

MR. DIBBLE: For some of the black start units, that's correct. We can -- we have permit

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limits that increase emissions so it can slowly ramp up in a blackout or in a black start condition, but not from a cold weather perspective. You know, operating in that condition, we still have the same permit to apply to as we would on a beautiful day in April.

COMMISSIONER CLODFELTER: So if the unit is starting up from black start, your permit may accommodate that. But if the Governor declares a state of emergency, your permit doesn't accommodate that?

MR. DIBBLE: Declaring a state of emergency, no, it would not accommodate that.

COMMISSIONER CLODFELTER: Thank you for the clarification.

CHAIR MITCHELL: Last question for me. You-all have described the Company's coordination with its various customer groups, and what I'm hearing is it mostly -- the communication coordination, at least with the larger customers, occurs between the account manager and the customer. Is that correct? Is there any -- just in terms of communication with other utilities, such as Natural Gas utilities or a Water and Wastewater Companies, does the Company have a more formalized protocol for coordinating with other utilities or do those communications occur, sort of, in the same way as with other customers?

MR. BARMER: They occur pretty much in the same way as other customers. Now, I will say with water facilities, we have governmental folks who interact with folks at county and state levels. And they're kind of intermediaries in many cases that they talk about issues that involve either the Company or their location, so there's probably more communications between us and the governmental entities than other general customers.

CHAIR MITCHELL: Okay. Thank you for that. Let me check in to make sure there are no additional questions for the Dominion Energy group.

(No response)

CHAIR MITCHELL: You-all may step down. Thank you very much for your comments here today.

MS. VITELLO: Thank you.

MR. BARMER: Thank you.

CHAIR MITCHELL: Oh. I'm sorry. Public Staff. Public Staff. I see some panicking over there. I'm sorry, guys. I'm going to turn the Public Staff loose. We're going to take a break in just a

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few minutes for our court reporter. So Public Staff go ahead and get started, and then we'll take a break shortly.

MR. METZ: Good day. My name is Dustin Metz. I'm an engineer with the Public Staff. I have some general questions, and they can go to anyone on the panel. Also, I have some general questions for PJM. So from PJM's perspective, if you have anything to add on, just request that you add on, that is required.

The Public Staff sent some discovery questions on March 25th. The response to question one highlights forced outage rates between Dominion's fleet and PJM. Could you provide some context as to why the units outage rates differ between PJM and Dominion?

MR. DIBBLE: So I can't speak for PJM and what makes up the value for them. They may be able to speak that, but from our perspective, 2014, we had some large units to run outage that crossed that Polar Vortex period that we did not have in 2015. In addition, that in 2015, we had the benefit of having Warren County online for that event, so a little bit different operating perspective for us. But I don't have any data on the difference in the PJM rate.

MR. METZ: PJM.

MR. BIELAK: As far as the 2014 event I believe we're speaking to?

MR. METZ: The 2014 or '15 event, yes.

MR. BIELAK: Correct. In 2014, there was a variety of reasons for the forced outage rate. I didn't come prepared with those statistics, the vast majority of which was gas availability.

MR. METZ: Okay. Thank you. And follow-up to that, does PJM provide any direction to PJM members or requirements for unit inspection processes, frankly someone like Dominion that needed to verify generators to be able to operate?

MR. BIELAK: Yes, we do a lot of outreach as far as cold weather reparations. As was previously stated, the entire PJM fleet is now capacity performance, so they are responsible for performing really at all times, specifically during strained conditions. However, while it is the responsibility of the generation owner, PJM does facilitate a lot of the required testing and checking as far as making sure that those units are fully prepared for winter operations.

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MR. METZ: Thank you. And how often does PJM perform those inspections or verifications? Is it annually, before the winter season, before the summer season?

MR. BIELAK: Correct, yes. So typically speaking, it's annually, prior to the cold weather operations.

MR. METZ: Thank you. I have some general questions on cold weather impacts for the generation fleet. Have there been any challenges with the coal generation fleet with potentially the coal pile freezing or coal resupplies? Again, this is bridging from 2014, '15, '18, and present day.

MR. DIBBLE: No. So, typically, we will bolster those supplies in the late summer and fall to ensure we have adequate supplies on site. We can't control what happens in the western part of the state. Typically, the weather might be a little bit different out there, but we ensure those supplies are full going into the winter, from a cold perspective. We don't want to have to rely on some type of a weather-related issue, either at a mine or with the railroad, that are out of their control as well.

MR. METZ: Let's say physically now it's

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setting on the pile and we had a freezing rain, and it's soaked in and is unable to move, do y'all make any preparations prior, start moving coal in advance or --

MR. DIBBLE: Yes. So we will keep coal silos or bunkers full within the power station. Some facilities have dry storage on site. But, typically, in a cold weather situation or falling weather situation, you take the first couple feet off the coal pile and that's where you're starting to get to the dry cold. Maintain, keeping it compacted when it's, you know, in a steady state. Proper drainage for the water and snow melt to run off, but, really, it's just about the proper management of that pile of assets that you have there.

MR. METZ: Thank you. For any of the cold weather events, have there been thermal generation plants or even the nuclear plants, has there been any freezing, let's say, the cooling tower or at the intake that have caused not necessarily unit outages but also unit derates?

MR. DIBBLE: For intakes, no. Those are on a -- they're on a pretty deep suction area, so we don't see a lot of free -- you know, the suction

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area's maybe 20 or 30 feet below, so you don't see a lot of freezing there. You will see some issues with traveling screens, maybe, but those are easily rectified just through keeping them in service.

And cooling towers, not really. Icing of a tower is a primary concern. It's more of a structural issue, maintaining icing off the tower, so you don't have some type of weight loading that could impact the tower, but not from a generation perspective.

Typically, they're designed with fans that you can reverse and exhaust the heat in different directions to melt the ice, but it doesn't really affect generation. I mean, they love the cold weather, so that typically is not a problem.

MR. METZ: All right. Thank you. Turning back discovery that we sent y'all on March 25th, follow-up to Question Number 6, would Dominion generation assets be generally dependent on critical or critical infrastructure, accounts like Natural Gas, heat, water cooling to certain generation plants? Maybe -- restate it, if I may. I guess I'm a little confused when we're about critical accounts or critical assets. I think the word critical is potentially interchanged. If you look at a customer

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who may be a critical customer, let's just call that a hospital. Well, generation units won't be dependent upon that hospital to keep a fuel supplier or a water supplier, et cetera. But, however, fuel supply or water supply would be identified as critical.

Could you delineate between critical infrastructure or critical nature?

MR. BARMER: I'm not exactly sure what your question is, but maybe I'm missing something there. If not --

MR. METZ: So in Question Number 6, it defines it as the contact list for critical infrastructure?

MR. BARMER: Right.

MR. METZ: So I guess I'm a little bit confused with what's the difference between a critical customer versus a critical infrastructure.

MR. BARMER: A critical -- so a critical customer is one that has been identified as having some critical function usually by the owner of whatever that account serves. Critical infrastructure is what we deem as things that we want to exclude from the Load Shed Plan. And, as I mentioned before, it could be other factors, like do they have on-site generation that covers certain components of their processes that they can withstand a 15-minute interruption and not be harmed, so to speak.

MR. METZ: Okay. And so then the annual notification, is that applied to both critical customers and critical infrastructures or is it only the --

MR. BARMER: Critical customers.

MR. METZ: It's only the --

MR. BARMER: So all the critical customers. And then if there are any changes made, then we assess that to determine whether it's critical infrastructure in terms of a load shed process.

MR. METZ: Okay. Thank you. So going back, do you know, offhand, how many critical owners respond to the annual reminder?

MR. BARMER: No, I don't. I don't have any response.

MR. METZ: And does Dominion audit the critical owner contact information to ensure that the reminders are, indeed, making it to the active participants, whether it's telephone, e-mail?

MR. BARMER: Yeah. We do follow up to be sure that they got the request.

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MR. METZ: And when you sent out the annual monitor, by what means is the reminder? Is it, what, via the key account manager, is it via telephone or is it via e-mail or --

MR. BARMER: It's any combination of those, depending on the customer. If their key account's signed, it'll go through them. If it's a direct contact through a governmental entity, it'll go to a contact point that we have with them.

MR. METZ: And on the annual reminder, when you send it out, is there just an expectation when you get the responses back, or is there something saying Dominion says we want these responses back in 30 days?

MR. BARMER: No. It's more or less on the customer, at that point. We allow them to provide us the updated information. So if they don't respond and provide us any updated information, we don't keep pursuing it, if that's your question.

MR. METZ: And so if they don't respond, do you just assume where you last left off is the status quo, or you'll say well, since you didn't respond, you're no longer critical and we're going to move you?

MR. BARMER: No. If they don't respond, everything stays there as it was. It's only for

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changes to the plan.

MR. METZ: Okay.

MR. BARMER: So if it's an existing critical customer, critical infrastructure, we don't make any changes to that, so it's not that we're taking things off the list if they don't respond. Everything stays on the list. We only change things that they won't change.

MR. METZ: Okay. Thank you. So I'm going back to my electrician days. I used to work on, say, remote or distribution. I mean, either, say, Natural Gas or even more water specific. So you go into -- you're driving down the road and you'll drive by a pit, 16 x 16 pit by 4 feet deep, and you got a bunch of water pipes that are running through it with telemetry, and it has a meter setting on it.

Those are more distribution-connected services for potential critical infrastructure?

MR. BARMER: Correct.

MR. METZ: Or critical customers. Would those -- walking back a little bit, when you were talking earlier saying yes, that they're transmission connected, they're clearly critical. But what about the distribution-connected circuits or distribution,

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the components that are able to load into the system? Are those designated as critical?

MR. BARMER: Yeah. That's really what this chart that we have that's -- those mostly are distribution-level customers. It's not transmission-level customers.

MR. METZ: Okay.

MR. BARMER: So all that classification is basically for distribution-level customers.

MR. METZ: And that's still dependent upon the owner to inform you-all to say this is the function of what its serving?

MR. BARMER: Right. Because we don't know what the criticality of any function of our customers have. They may have something that -- it may be critical to some other component of their process or system that we don't have a clue about, so we rely on them to tell us which accounts or which items in this that we serve are critical to their processes.

MR. METZ: Thank you. And follow-up to Question Number 7, Dominion stated there's no reminders sent to Natural Gas providers. I want to ensure them using the correct venacular in the context of Natural Gas providers, do you mean Natural Gas

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providers is either an LDC or Transco?

MR. BARMER: Either. For us, either.

MR. METZ: And then the reasoning behind why no reminder is sent to those Natural Gas providers -- or can you provide context to why no reminder is sent to them?

MR. BARMER: As I indicated earlier, that the -- once an account is originally set up and that criticality is set, especially for some type of a utility type service, usually that criticality doesn't change. But if it does change, we rely on them to tell us, hey, this has become a critical -- what was not critical before has become critical now. But we don't send a reminder to them specifically to say, hey, look at all your accounts and determine if any of these have changed to critical.

MR. METZ: As a late-filed exhibit, could you provide a locational map of the 34 circuits subject to load curtailment?

MR. BARMER: Could we provide those?

MR. METZ: Yes.

MR. BARMER: Yes.

MR. METZ: Thank you. And follow-up, the Company's response to Public Staff Question Number 9

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for the 2014 event -- and some of these questions are also pulled from Duke Energy responses, so I apologize. For the 2014 event, did DEP receive 200 megawatts from PJM or is that 200 megawatts sent from Dominion's allocation through the VACAR VRSG.

MS. GRIGG: That might be from Duke's responses.

MS. VITELLO: What question was that, Dustin?

MR. METZ: So -- and following up to Question Number 9 from Dominion's responses and looking back and correlating some information that we got from Duke, which I can go find that response, I interpret the response to be that -- and I thought I also heard earlier today that -- for the last 10 years, Dominion has not been called upon for their VACAR or the VRSG a lot.

But when I was reviewing Duke's responses -- and this might be a question better off for Duke or look more to the PJM folks to this, was in 2014, I believe it was 2014, that 200 megawatts came from PJM. So I guess I was curious just to verify, that was not Dominion's VIRSIG allotment, that was PJM's?

MR. BIELAK: It may have been emergency

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power.

MR. METZ: It may have been emergency power?

MR. BIELAK: Yes.

MR. METZ: And not the VACAR VRSG?

MR. BIELAK: Correct.

MR. METZ: Okay. Can you explain the differences between the two and how they would classify in one and not the other, please?

MR. BIELAK: Yes. So as far as emergency power's concerned, that would be actual interchange observed in realtime, from the PJM balancing authority to the Duke balancing authority, as opposed to reserves which are deployed after a disturbance on the system, namely the loss of a large unit.

So the reserves were held and maintained by Dominion Virginia during that time frame. However, to further assist the Carolinas, PJM was able to provide that emergency energy which flowed in realtime across the ties.

MR. METZ: All right. Thank you. And I'll look to Duke team if I misinterpreted your responses, could you please clarify when y'all come up.
Mr. Hinton.

MR. HINTON: If the Commission will indulge

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me, I don't have any questions. I just have a comment.

Ms. Vitello, when you started the conversation, you talked about a 2014 vortex event. And I want to compliment your company and PJM for doing a very well publicized study research effort, and you made some significant changes to your capacity market to make sure the power was there when it was called upon. This was -- the publicized element was well-documented on your website. This was not necessarily the case with not showing signs of Duke or particularly SCE&G.

At that time, I only learned about their shortage of power, I believe 300 megawatts short on January 7th, '14 to a FERC publication. Then, they nailed me to talk to the South Carolina staff and get an ex parte or -- excuse me, a communication on what actually transpired on that day and who they depended on for power and who they did not. As you know, DEP was very short on capacity and they cannot provide any emergency power. There was some provided by, I think, Duke Carolina but not Progress.

Anyway, the point was it was well-publicized. There was a little shedding of that.

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There was actually 17,000 customers who were shed in the southern area of the service territory, to the Charleston area, in particular. It was not well-publicized in the newspaper. I could find no report. I guess customers felt like a line was -- had a tree on it and whatnot. Anyway, but you-all attacked this issue with -- I think with sophistication and grace, and intelligence and effort. So I compliment you, Dominion, and PJM for your efforts, and I think that served the public well.

MS. VITELLO: Thank you.

MS. EDMONDSON: I had a couple of questions, just to follow up. What is an example of a high profile customer? You mentioned that in one of your categories.

MR. BARMER: Well, you can see the various categories here. So prisons are high profile, not necessarily something that's excluded from any load shed. Say critical traffic signals. So if you look down through that list, you can see some of them. That's just a sampling of some of the types of things that fall within the category. It doesn't mean they're not important. It just means that they're not excluded from the load shed, because the thing to

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remember with load shed is you're trying to shed load to save the system, so you don't want to make everything critical or everything so high profile that you don't have anything left to work with. So...

MS. EDMONDSON: Are cell towers in Group Z you talked with Commissioner Gray about a problem of needing cell --

MR. BARMER: No, they're not.

MS. EDMONDSON: Has that been considered as we become more and more dependent on cellular?

MR. BARMER: One of the problems with cell towers are they're everywhere. So there again, if you make all of those critical, you most likely would deplete your ability to shed a lot of circuits. And, as I mentioned, the intent of a load shed program is to save the system, to shed load as much as you can to save the system. So if you exclude too many things -- and cell towers are a good example. Now, we do have communications with cell tower, cell owners across our territory, which I would presume happens with many utilities. And they have key sites as well that they also put backup generation in, so not every cell tower goes down. But, you know, when it does go down, if you're not near one of those that is a critical one

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for them that has backup generation, you probably would lose your cell service after some period of time. And, also, some do have backup batteries systems in place that'll hold them up for a short period of time.

MS. EDMONDSON: How do you see an increase in distributed energy resources where you have more net positive circuits? How do you see that affecting your load shed program?

MR. BARMER: Well, as I noted, it's definitely something that has drawn our attention in the North Carolina area over the last three to five years. It complicates it a bit because now, not only are you trying to shed load, but as we talked about before, there's probably times in the day and night, and evenings, depending on when the situation is there, that we may need to do more segmentation of time such that you don't exclude them all the time, but you may be during certain times of the day.

I think that will evolve as time goes on. But right now, we don't have that technology in place to know everything we need to know, every instant of the day to make the changes in the program.

MS. EDMONDSON: And my last question was for

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PJM. In the response to Number 14, PJM said it had not conducted energy transfer studies that were recommended in the FERC/NERC report, but you discussed the capacity benefit margin verification study as well as you've done some maximum import/export transfer capability studies. Are those a complete substitute for the recommended studies that the FERC/NERC report recommended?

MR. BIELAK: Unfortunately, I'm not the one at PJM to best answer that question, so I cannot say that it's a definitive, 100 percent replacement or not.

MS. EDMONDSON: Okay. Can you tell me any differences that you're aware of?

MR. BIELAK: I'm unaware of any differences in their case setup. Unfortunately, those are run by a different division within PJM.

MS. EDMONDSON: Okay. Thank you. I think that's all for the Public Staff.

CHAIR MITCHELL: All right. At this point, we will take our first break of the day. Let's go off the record, please, ma'am. We will be back on record at 11:30.

(Whereupon, a break was taken)

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CHAIR MITCHELL: Let's go on the record, please. Before we get to Duke, I have two more questions for the PJM team, just continuing to explore the changes, if any, that will occur as a result of Dominion's withdrawal from the VACAR reserve sharing group. Due to Dominion's leaving VACAR, will the transmission that had been reserved for those VACAR obligations be freed up for other uses such as generator interconnection or other transmission services request?

MR. BIELAK: Unfortunately, I'd have to explore that and provide an answer at a later date. I don't have that answer in front of me right now.

CHAIR MITCHELL: Okay. Is that -- that question is clear though?

MR. BIELAK: Yes. I do understand the question, yes.

CHAIR MITCHELL: Okay. Sort of a related question. So we understand that the transmission system will have the same capability, but will that same capability still be available for energy transfers during emergencies? And I believe you may have already answered this question. I just want to be entirely clear.

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MR. BIELAK: Yes. There would be no changes to the availability of energy transfer on the transmission system during regular operations or emergency operations.

CHAIR MITCHELL: So Dominion's withdrawal from VACAR is not going to change the possibility for emergency transfers, the potential for it?

MR. BIELAK: That is correct, yes.

CHAIR MITCHELL: Any capacity that would be available for that purpose?

MR. BIELAK: Yes.

CHAIR MITCHELL: Any additional follow-up on those questions?

(No response)

CHAIR MITCHELL: Thank you, guys. Y'all may take your seats. Next up, we have got Duke. Mr. McCoy, if you could. There it goes. And just for purposes of the record, gentlemen, would you please introduce yourselves.

MR. ROBERTS: Yes. So my name is Sammy Roberts, and I'm the General Manager of Transmission Planning and Operations Strategy.

MR. McALLISTER: Good morning. I'm Joe McAllister. I am the Managing Director of System

Optimization.

MR. ROBERTS: So good morning, Commissioners and Chair Mitchell. Thank you for this Technical Conference opportunity to provide more context around Duke Energy's responses to the Commission's questions concerning Docket M-100, Sub 163 concerning cold weather preparedness. This morning's presentation by Duke Energy will offer additional context concerning the five topics in 19 questions put forth to Duke Energy in the January 26th Commission Order. Duke Energy will be glad to pause at any time to answer Commission questions during the presentation so you don't need to feel like you have to reserve the question until the end.

The first two Commission questions in your order were related Duke Energy's lessons learned from the February 11th, 2021 ERCOT event. So I'd like to start with a brief summary of the highlights from the event, and it'll be very brief.

So, first, ERCOT did -- have reached about 34,000 megawatts of generation unavailable for two consecutive days.

Second, the 23,400 megawatts of firm load shed within ERCOT, SPP, and MISO represented the

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largest controlled firm load shed event in U.S. history.

Third, four and a half -- more than four and a half million people in Texas lost power, with some losing power up to four days, and some of those people losing power being subject to sub-freezing temperatures.

Fourth, power was cut to nursing homes Natural Gas facilities, and water pumping stations, and people were ordered to boil drinking water.

And, lastly, from the NERC/FERC report, there were two main causal factors. The first being generating units were severely unprepared for cold weather and failed in large numbers. And second, Natural Gas production issues to cold weather interrupted heating and gas generation.

So, how is Duke going to avoid these issues experienced in North -- ERCOT or how do we avoid these issues, and how are we prepared for not having the same cold weather impacts? So Duke Energy continuously learns where we pursue operational excellence. We are pursuing continuous improvement with our procedures and processes. And, as I said, we've learned from past cold weather events.

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So the first one I'd like to refer to is the 2011 ERCOT cold weather event. And with that one, we learned to ensure proper operation of circuit breakers, to avoid things like, you know, the grease becoming hard and not operating properly or having low gas pressure in those gas circuit breakers.

Second, we learned about the importance of established protocols for canceling generation and transmission outages. And, also, we learned the importance of fuel switching capabilities. In the January 7th, 2014 Polar Vortex, we learned about the importance of starting generators early, and that way you can make sure that they can run effectively on that fuel oil, or if there are any issues, you may have time to fix those prior to the actual cold weather incurring on the system.

Planning for fuel contingencies; such as, if you plan your gas and you have a large generator, nuclear cold unit to trip, you need to make sure you have planned for that contingency with respect to your gas procurement. We also learned to ensure heat tracing, its design properly, and electrical circuit diagrams are accurate for freeze protection circuits. And we also improved our coordination and

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communications associated with our load reduction plans, and I'll have more about that later in the slide there.

With the February 20th, 2015 Polar Vortex event, probably the coldest winter morning for DEP and DEC, where DEC realized a 7-degree system average temperature, and DEP realized a 10-degree system average temperature, we actually postponed the start of a nuclear refueling outage, if you remember that event in 2015 by seven days. And that was a decision that had to be made, and we had established the right authority for the groups to make that decision. And we made that decision, and it paid dividends for serving our customers reliably that week.

We also learned the importance of prompt corrective action with respect to freeze protection -- implementing the freeze protection deficiencies -- excuse me, freeze protection for deficiencies and operating our system at these higher winter peak demands. And just to give you a reference, the DEC/DEP combined demand was around 36,700 megawatts for that morning. And only one day had surpassed that, and that was January 5th, 2018 at 36,900 megawatts.

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The next was the January 2nd through 8, 2018, bomb cyclone event. And with that event, Duke learned that our load forecast model performance had some improvement opportunities, and specifically for the evening peak and overnight loads. And you say why not the peak? Why evening? Evening peak loads and overnight loads has to do with your fuel consumption, right? I mean, if you don't forecast accurately every hour, not just the peak, your fuel plan will be off, and your fuel plan can't be off with the sustained cold weather for a week like we had in early 2018.

So, also, we learned that we need to have better communications still with a load reduction plan in certain areas that we didn't address back in 2014 and '15. In the remainder of this presentation, I'd like to discuss some of the lessons we learned from the 2001 ERCOT event. So based on Duke Energy's experience, diversity of resources and diversity and firmness of fuel sources are key enablers for reliable power supply during a cold weather event. ERCOT's portfolio was highly dependent on Natural Gas, and the capability that ERCOT generators had for operating on backup fuel had not being tested and wasn't reliable. And just the numbers to bear that out, 87 percent of

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the fuel issues involved Natural Gas fuel supply, 13 percent involved issues with other fuel such as coal or fuel oil, 41 out of 392 generators were capable of fuel switching, and only 86 percent of those -- or excuse me. 86 percent of those attempting to switch fuel to fuel oil failed, so 86 percent failed to properly switch to fuel oil. And I'll cover Duke Energy's practices for testing fuel switching capabilities in later slides.

So the next set of Commission questions --

COMMISSIONER DUFFLEY: Mr. Roberts, can I interrupt?

MR. ROBERTS: Yes.

COMMISSIONER DUFFLEY: So this 86 percent that failed in the fuel switching, is that similar to what happened in the Polar Vortex? I know you mentioned this as a learning. We didn't hear it before, but part of the problem with the Polar Vortex is the companies weren't annually testing or quarterly testing to make sure their units would actually start up. Is that a similar type of situation that you're discussing that this can be fixed, this 86 percent fail rate can be fixed with quarterly testing or annual testing to make sure that those units will switch?

MR. ROBERTS: Yes. Properly testing fuel-switching capabilities helps. Starting units early, making sure that they can run on that fuel oil, even if it's just for a few hours when it's getting cold, helps. And, then, also remediating any issues discovered in that testing, such as, you know, (1:55:56) how I deal with Delta P across the filters indicating you need to change filters out, or indications of fuel nozzles clogging. Those sorts of things can be remediated if detected during that testing.

COMMISSIONER DUFFLEY: And it's my understanding, I heard you state, that you have -- the Company has been increasing their testing of all of these units?

MR. ROBERTS: Yeah, that's correct. So we have a guidance document in place now that requires quarterly testing of simple cycle CTs, and it requires annual testing of the CTs associated with combined cycles.

COMMISSIONER DUFFLEY: Okay. Thank you.

MR. ROBERTS: You're welcome.

COMMISSIONER CLODFELTER: Since we're on

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this -- I had questions for you later. But since we're on the topic now, let's just get them out of the way now and we won't come back to them. So if your weather forecasts are showing -- your 15-day out forecasts are predicting a problematic event 15 days out, do you test at that point?

MR. ROBERTS: Yes. System operations will request -- if we see extreme cold weather coming from the meteorologist's forecast, we will request testing of units on fuel oil capability if we know we're going to need to run those with respect to our fuel plan.

COMMISSIONER CLODFELTER: Okay. Thanks. That saves a question later. Before you go on too, I also have a question about your pie chart. They're just simple questions about the chart, and we will come back to them.

MR. ROBERTS: Okay.

COMMISSIONER CLODFELTER: The source data -- your 2035 pie chart, the source data is the 2020 IRP. Is that the base case or is that one of the other cases?

MR. ROBERTS: It is the base case.

COMMISSIONER CLODFELTER: It is the base case?

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MR. ROBERTS: Yes.

COMMISSIONER CLODFELTER: And on that chart, what does DFO stand for?

MR. ROBERTS: Dual Fuel Operations.

COMMISSIONER CLODFELTER: Dual Fuel.

MR. ROBERTS: Yes.

COMMISSIONER CLODFELTER: So those are your dual fuel units?

MR. ROBERTS: So those are -- has solely coal fire generators, but they're being converted to be able to operate on coal or gas. That's our dual fuel. You'll also notice a pretty good section of the pie with gas CTs. Primarily, all of those have fuel capability.

COMMISSIONER CLODFELTER: Well, I'm glad I asked now because we were going to get to it later in a series of questions. So the DFO units were converted coal units?

MR. ROBERTS: They can run on gas or coal or a blend, that's correct.

COMMISSIONER CLODFELTER: So they can run on coal. In 2035, they're predicted to be either coal. So, for example -- I don't think this is confidential. So, for example, that would be Belews Creek?

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MR.ROBERTS: So -- and this was 2020 IRP information.

COMMISSIONER CLODFELTER: Right.

MR. ROBERTS: So just --

COMMISSIONER CLODFELTER: I understand. I understand.

MR. ROBERTS: But -- so, yes.

COMMISSIONER CLODFELTER: It's all up in the air.

MR. ROBERTS: In the 2020 IRP, you have some Marshall coal units.

COMMISSIONER CLODFELTER: Right.

MR. ROBERTS: Belews Creek and Cliffside 5.

COMMISSIONER CLODFELTER: Got it. Thank you.

MR. ROBERTS: You're welcome.

CHAIR MITCHELL: Mr. Roberts, I just want to make sure I heard you correctly. Do all of the companies, both companies, CT units have dual fuel capability?

MR. ROBERTS: So some of the CTs are oil only.

CHAIR MITCHELL: Okay.

MR. ROBERTS: And some of the CT sites that

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are dual fuel, it's hard to get enough gas during the wintertime due to the demand, and so they're proficient. They run on oil several times, and that's where a lot of the other fleet got their lessons learned from about running reliably on fuel oil, and that's by Wayne County or Lee Energy Complex. But all the other stations, subject to check, all the other CT stations have backup fuel.

CHAIR MITCHELL: Okay. All right.

COMMISSIONER CLODFELTER: While we're on this, so again, let's -- since we're on it, let's stay. So I was looking at that chart you've got on who's got dual fuel capability, and one of the things that jumped out at me is that you converted, over recent years converted three coal-fired units to combined cycle units, and those were not given dual fuel capability when the conversion occurred. Why was that?

MR. ROBERTS: Converted coal units to combined cycle?

COMMISSIONER CLODFELTER: Yep. Buck, Dan River and --

MR. ROBERTS: Okay. I got it. Replaced the generation.

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COMMISSIONER CLODFELTER: Yes.

MR. ROBERTS: Yes. So, we were able to get firm gas supply associated with those generators. And with that firm gas supply and being close to Transco, very close to Transco, we felt that the risk was almost zero associated with losing gas supply to those units.

COMMISSIONER CLODFELTER: So, that's why the decision was made, not when they were converting coal to --

MR. ROBERTS: Right.

COMMISSIONER CLODFELTER: -- combined cycle they -- okay.

MR. ROBERTS: That's correct.

COMMISSIONER CLODFELTER: And there's no plan going forward to dual fuel those?

MR. ROBERTS: Not that I'm aware of, sir.

COMMISSIONER CLODFELTER: Thank you.

COMMISSIONER McKISSICK: Can I ask one quick question? And that's this, when you actually move to say one of the fuels that are alternative fuels for these dual fuel capacity units, how long does it actually take to do so? I mean, let's say right now gas was interrupted and you wanted to use oil. I

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mean, how long does it take to actually put that into place and get it operating?

MR. ROBERTS: Right. So, if it's a sudden operation, excuse me, a sudden loss of gas, a sudden loss of gas pressure, then the unit is going to trip.

COMMISSIONER McKISSICK: Okay.

MR. ROBERTS: And so you're going to have to restart on oil. If it's a controlled switch, usually what we'll do, let's say it's a five CT site, we'll take one CT at a time, we'll bring it, start it on gas, bring it down to, you know, very low output level and switch to oil, and we can quickly do that.

Same thing to prevent coking. When we bring it offline -- if it's controlled, we'll try to bring it offline using a little bit of gas to fire at the end to prevent coking at the nozzles that can impede its operability. But that's how we do fuel switching.

COMMISSIONER McKISSICK: Got it. And in terms of your fuel supply, let's say if it's oil, I mean, and I asked Dominion this question about what supplies they actually keep online. Are you going to get to that later in your presentation or --

MR. ROBERTS: Yeah.

MR. McALLISTER: Yeah, I think the -- you

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know, in our data response we said roughly it was around 80 hours on average --

COMMISSIONER McKISSICK: Okay.

MR. McALLISTER: -- for a typical site. Now, all sites aren't created equal. Some are, you know, have more or less capability, but that's a general rule of thumb. And in that data response, that was at a point in time, too, when we were coming out of winter. If you asked us that same question today, it would probably be closer to 90 hours because we're replenishing for the summer season. But, yeah, it's roughly the same as they said, you know, roughly three, three days on average across the CT fleet.

COMMISSIONER McKISSICK: And when you have that type of oil capacity that's available, is there a certain point in time where the fuel itself may not be as reliable or stable?

MR. McALLISTER: No, I think that the plant facilities, you know, they handle that. But, yes, it can set in the tanks for a very long time and it's still usable.

COMMISSIONER McKISSICK: And without any problems in consumption --

MR. McALLISTER: Correct.

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COMMISSIONER McKISSICK: -- burning. Okay. Thank you.

COMMISSIONER CLODFELTER: Have you increased your supply or your reserves since Texas? Oil reserves --

MR. McALLISTER: Oil for burning?

COMMISSIONER CLODFELTER: -- for fuel --

MR. McALLISTER: I think we generally try to go into the seasons at least 80 percent full, I mean just as a rule of thumb. And one of the things, remember too, you don't want a site to be completely full because one of the tricks of managing fuel oil, when you see something coming is getting the product moving, right. It's not just the supply, it's the trucks, so. But generally speaking, we're pretty full going into winter season at most sites.

COMMISSIONER CLODFELTER: Well, the question though was, have you increased your capacity for --

MR. McALLISTER: No, we have not increased our physical capabilities at any site.

COMMISSIONER CLODFELTER: Okay. And just for a moment, back again, to confirm on the three CC units that were converted, those are firm supply contracts? Those are all -- not interruptible contracts? Those are --

MR. ROBERTS: That's correct.

COMMISSIONER CLODFELTER: Thank you.

MR. ROBERTS: So, based on our experience, as I stated before, diversity of resources and diversity in permanence of fuel sources are key enablers for reliable power supply during cold winter weather. And as I told you ERCOT's ability to switch fuel was an Achilles heel. And so, once again, I will speak more to the practices we have for switching to fuel in addition to the answers that I provided to your questions.

So, the next set of Commission questions are related to weather and load forecasting. And the next couple of slides will provide context around Duke Energy's capabilities for weather forecasting in the associated communications and load forecasting methods that we have associated with the weather forecast.

So, Duke Energy does have five full-time meteorologists and they receive NOAA environmental data and information in near realtime and that's the same data that the National Weather Service utilizes. And using this data and other vendor-supplied data, the meteorologists develop a 15-day weather forecast

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for specific areas in our service territory, and those weather variables that they forecast include dry-bulb temperature, cloud cover, dew point, and wind forecasts for key locations.

The hourly weather load forecast or, excuse me, weather forecast are provided as inputs to the vendor load forecasting models. And so it's critical that that weather forecast be as accurate as possible in order for the load forecasting models to forecast load as accurately as possible.

And those, once again, those weather inputs are utilized in the vendor-load forecasting models to forecast the Duke Energy Carolinas and Duke Energy Progress balancing authority loads. And balancing authority is key because you have history. As long as you don't change your balancing authority boundaries you can always have some correlation between the weather at those centers and the historical balancing authority load.

And so the accuracy of the hourly load forecast, that's also critical with respect to fuel planning as we discussed with the revelation and the bomb cyclone event. You not only need to be accurate forecasting the peak hour, you need to be accurate

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forecasting the energy used during the day and the load at each hour.

So, for situational awareness and the potential for and/or imminent cold winter weather, which is very key to ensuring preparedness of our enterprise and our customers and wholesale customers, et cetera. That preparedness requires a somewhat accurate weather load forecast. So our meteorologists, they issue cold air watches that look 15 days ahead and give us projections of any cold air mass moving in and duration that that could last as well as winter precipitation that could occur with that cold weather. And so they issue cold air watches and weather alert communications to the Company to provide for that awareness.

They also participate in our winter, annual winter weather webinar groups, winter preparedness webinar groups, discussions, and they give a winter season forecast in that webinar and they also participate in what we call our tailgate meetings where if there's an impending event. Once again, it's a part of our readiness practices to have this tailgate meeting. And in that, if -- we start the beginning of that meeting with safety, of course, and then we go into a discussion from the meteorologist about the weather forecast.

COMMISSIONER CLODFELTER: Before you move the PowerPoint performance, a question or two about the weather forecast. Is that okay?

MR. ROBERTS: Okay.

COMMISSIONER CLODFELTER: Since you invited us to ask you along the way, with the Chair's permission, I'll take you up on it.

MR. ROBERTS: That's great.

COMMISSIONER CLODFELTER: So, in the written response to the question here that we're talking about on weather forecasting, the Company says it blends the data from the selected locations; for the 15-day forecasts it blends those into weighted averages for DEC and DEP. My question really hones in on the real difference between DEP East and DEP West. Do you generate a separate forecast, 15-day forecast on an hourly basis for DEP West and DEP East?

MR. ROBERTS: So, we have a forecast for our DEP West area that's based on weather variables associated with primarily Asheville since that's the biggest load center, and then we also have our eastern, we call it our eastern area load for DEP

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East. The overall forecast used for fuel planning and if we're unit commitment is our total DEP balancing authority area. But we do look at the west in isolation, both from a resource adequacy perspective, a fuel adequacy perspective, et cetera, versus the demand that's forecast.

COMMISSIONER CLODFELTER: So, operationally talk me through your 15-day forecast shows you've got a horrendous event coming to the mountains but you're in sunny weather down east. What happens?

MR. ROBERTS: Right. So, we will focus on that western area in the weather forecast, however, realizing that that weather may decide to go a little bit more east as well and so we'll plan on that contingency. But looking at the west, we'll make sure that the firm gas supply is there for our Asheville units. We'll make sure that the oil supply is there. We'll make sure that transportation is ready to resupply if that's needed with respect to oil. And we try to be very proactive on that, because you never know what winter weather may do with road conditions, for example.

And so we will also talk with the plant about staffing with respect to unloading that fuel

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oil. So, there's a lot of preparations and discussion going on with respect to preparing for that system. And, of course, our DEC area, it blends over into that western area as well. So there will be a lot of discussions with that side of their service territory as well or the DEC side of the service territory as well. And so we'll plan for the event accordingly based on the forecast, but we'll also consider a contingency situation and prepare for those as well.

COMMISSIONER CLODFELTER: The bottom line is you do prepare a differentiated weather forecast for the western balancing area?

MR. ROBERTS: That's correct.

So, the next set of questions deal with power plant performance and this is where we get into the fuel switching and those sorts of things, but -- and I'll provide more context associated with our responses to the Commission's questions on power plant performance during cold weather events.

So, per the request, we did look back at the last three years and we didn't have any of our generating units - coal, gas, hydro - that were unable to operate during the last three winter peaks. And we -- though they had a little bit in the preparation,

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you know, they weren't severe cold winters as compared to like 2014, '15 and '18.

But with that said, you can see in the progression from 2014 through 2018 how we've institutionalized lessons learned in procedures. We're executing on those procedures and it definitely paid dividends in 2018. We saw the performance was there and we were able to reliably serve our customers during that week.

Also, diversity of generation, as mentioned earlier, and diversity of fuel sources is important but not just during extreme weather. We're having to look at that, you know, more seasons and for different types of weather.

Gas burning plants, basically, once again for those that, you know, the gas supply could be curtailed under an extreme event, we do have backup fuel supplies associated with that.

And, once again, back on testing, Duke Energy does test its combustion turbine fleet on liquid fuel and we have an internal guidance document for prescribing that test that requires that testing, and it does require quarterly testing of the CTs and annual testing of the CTs associated with the CCs.

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Also, you asked a question about solar and wind performance, what we might expect there with respect to cold winter weather. And the one thing you'll see from the graph on this slide is that there are fewer daylight hours in the winter, so you have less total energy even on a blue sky day with solar but also the weather is significantly variable during the winter.

You can have consecutive cloudy days. You know, you can have cloudy days followed by a snowy day. And that can significantly impact your solar output. So we have to keep that in mind as we move forward with respect to carbon production.

We'll definitely need to be able to do things like be able to shift some of that solar energy to a critical peak time, and we'll also need to supplement this solar capability with other generation that is able of achieving high capacity factors.

And just for reference, during the 2018 bomb cyclone event, our coal-fired fleet experienced very high capacity factors, 90 percent; that's really high. And so when we think about winter operations going forward, if we had another bomb cyclone event, we need something to replace that coal-fired generation that

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can demonstrate that same performance and provide that same performance.

So, with respect to fuel planning and fuel coordination, that's really important during the preparing for winter peaks. This diagram does depict some of the aspects of the fuel planning process, but it also depicts the integrated nature of all the groups that are needed to be involved in this fuel planning. And so you need system operations. You need generation. You need Joe's fuels and system optimization group. You need load forecasting. You need to commit meteorology. All those groups need to be involved in that fuel planning in order to have a -- make sure we have adequate fuel to get through the cold weather event, you know, some duration.

Also, you know, the more proactive you can conduct this fuel planning, the more successful you're going to be, and Duke does conduct proactive fuel planning. For example, we started having fuel planning meetings around Christmas time to get ready for that bomb cyclone event. And so that, once again, that paid dividends with respect to having an adequate fuel plan and ensuring a reliable power supply.

With respect to looking into the future a

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little bit, with respect to the cold weather operations with high renewable penetration, for cold weather operations with a high renewable portfolio, we will keep on institutionalizing in the procedures any learnings. And, also, it'll be -- it will be important for us to be able to shape demand more with DSM and DR tools and, as I stated before, be able to shift solar energy into the peak hours through the use of storage.

Diversity will continue to be important to avoid common mode failures such as occurred in Texas with the gas generators. Fuel planning will continue to be paramount. And, also, I'd like to reiterate with the variable nature of renewable output, we'll need to make sure we have supplemental generation to be able to provide that high capacity factor capability similar to what we saw with the coal generation during the 2018 event.

The other thing is historical correlations. A lot of people don't think about this. But historical correlations between that temperature and historical load are going to start breaking down. And the reason is because some of that load you were considering in that correlation in the past is going

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to be netted out with behind-the-meter resources and so that has to be considered going forward, and we'll have to adapt our tools and methods going forward to provide for an accurate load forecast.

CHAIR MITCHELL: Mr. Roberts, I'm going to follow up there. So, help me understand how you do that? I mean, is the Company -- are the Companies already having to adapt to shifting and shaping that's going on as a result of behind-the-meter tools?

MR. ROBERTS: So, currently we telemeter, subject to check, 500 kW and above solar output. So, a lot of the stuff that's connected distribution we telemeter. So, we consider that as a resource, because we have a PPA, we consider that as a resource serving that demand. And so we still have a pretty good temperature-to-load correlation. That can be past history. It will be correlated to future load associated with those predictor temperatures and weather data.

Going forward, if you -- and I'll just throw this out -- if you have a lot of Tesla battery vols, rooftop solar, EVs, et cetera, masking that load, commercial, I mean, commercial can be really big, right, if you have a lot of that, those type resources masking that load, you're going to have to look at those trends and factor those trends into your load forecast.

CHAIR MITCHELL: So that makes sense to me. So how much of that are you already having to do?

MR. ROBERTS: So, because there is not a -- because we telemeter the 500 kW, we're not having to do that currently.

CHAIR MITCHELL: Okay. And so looking down the road, you anticipate that the Company may have to begin?

MR. ROBERTS: That's correct.

CHAIR MITCHELL: And so how do you plan for that?

MR. ROBERTS: Right. Once again, we'll have to use data analytics and trend adoption of different types of technologies behind the meter that are masking that load. And based on that trend, we'll have to have new weights or adjustments associated with our load forecasting tools. And there's some really smart load forecasting vendors out there, and I'm sure that they'll have to adapt their tools to these considerations.

CHAIR MITCHELL: So, what I'm hearing you

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say is there will be -- you will have some ability to -- let me rephrase. It's not going to be a situation where you're reacting in realtime as more and more of this technology is deployed behind the meter, but rather there will be some analysis that the Company can do so that you're not reacting in realtime?

MR. ROBERTS: Correct. We'll definitely try to be proactive on this.

CHAIR MITCHELL: Okay.

MR. McALLISTER: And I'll add one more thing, too. We do have a separate solar forecasting process as well, right. So, we talked about it off load, but there's an internal team within the meteorology team that actually, today, there is a model that forecasts solar. You know, they're working with the energy control center, the project developers to get better realtime information, particularly for distributed solar. So, there is -- you know, today we do have a good process but it needs to continue to evolve and convert --

COMMISSIONER CLODFELTER: You say that's integrated into your meteorology team?

MR. McALLISTER: Yeah, it's a separate

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model. It's actually a -- it's an open-source platform that -- you know, government, it's an open-source solar forecasting tool that would -- built by a bunch of community developers. We use that. It sits on our weather server and we are forecasting solar every day, every hour, so there is some lady that that is their job. And in terms of this technological advancements and just information, a lot of it is data, getting better realtime data. That is in process but it will continue to evolve.

MR. ROBERTS: Okay. The next set of Commission questions deals with load shedding and curtailment planning. And the following slides will supplement Duke Energy's responses.

So, first, DEC and DEP do not have any critical gas facilities on the interruptible plans. And also, critical natural gas and water infrastructure has been validated as critical load and is the last to be shed in our current load shed scripts. And that's done through the distribution planners in each region communicating with account managers, and knowing what loads are on -- customers are on those circuits, and basically incorporating that data into the criticality of that circuit.

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We are looking at the potential for removing some of these critical loads from the load shed program. So, there is critical gas infrastructure, wastewater processing, et cetera. There is a potential for being able to remove those totally from the load shed program, so we're looking at potentially doing that.

Also, with respect to load shedding, we do conduct annual training with our system operators on our system restoration plan as well as our load shedding process, our load reduction plans, including firm load shedding. And that's done through a variety of simulation exercises, as well as tabletop, as well as reviewing the components of our load reduction plans, as required by the NERC standards.

Also, I've learned in the recent GridEx drill with a load shed focus, communications need to be ready and dispersed through multiple channels and so communications have been refined and are more precise about the communication to customers. Also, in that GridEx drill, we learned that we need to refresh employees on the timing and urgency associated with load shedding. I will explain that a little bit more on one of the next slides.

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So, on this slide you can see our prioritization associated with our firm load shed programs. And so generally residential customers, small and medium commercial customers and industrial customers, they are shed first. And based on, once again, the feedback from the regional planner that we get and the incorporation into the load shed scripts determines the prioritization if they fall in that lowest priority group. And then second, large industrial and wholesale customers served from distribution.

And then lastly, and representing a small amount, a smaller amount of the load for that region is hospitals, nursing homes, critical agencies; media centers that we're utilizing to communicate those critical messages, et cetera, that all emergency entities, not just Duke Energy, are using to communicate those critical messages. And then also included in the group would be the county and municipal water systems, the wastewater treatment, sewage treatment, et cetera, and gas compressor stations as well if they are fed off distribution.

So, looking at ERCOT's firm load shed graph, which is on the right of this slide, one of the things

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that's important to note, and I think this is one of the reasons in the GridEx exercise this came out, is how fast this load shed event occurred, within 30 minutes they were -- and this is just this first line. It's not even one of the red circles, getting to one of the red circles but in this first ramp up, which was extremely quick. In the first 30 minutes, they had shed 5,000 MW of load. Within 40 minutes, excuse me, 35 minutes, they had shed 8,500 MW of load.

And then in 40 minutes, they shed 10,500 MW of load. So, in 40 minutes, 10,500 MW of firm load was shed, and that's looking at a forecast at that time of the morning, if I remember correctly, around 49 GW of load. Now, they would have gone up over 70 -- 70,000 MW, 70 GW that morning if they would have been able to serve offload, but they had to implement this firm load shed.

So, once again, the GridEx drill revealed that we need to more broadly educate our employees on the load shed process and how fast it can occur.

COMMISSIONER CLODFELTER: Mr. Roberts, on that slide, what does UFLS stand for?

MR. ROBERTS: Sorry.

COMMISSIONER CLODFELTER: An abbreviation for what?

MR. ROBERTS: UFLS is Underfrequency Load Shedding. So, with underfrequency load shedding, what you're doing is at the substation, you're detecting, there's an under-frequency relay. You're detecting under frequency. Our first level is 59.3 Hz. It's really low. If you get down to 59.3 Hz, these under frequency -- I think it's .28 seconds, these under-frequency relays are going to activate and they're going to automatically shed that circuit. And so we have to make sure that we have a certain amount -- per NERC standard, we have to make sure we have a certain amount of load for each underfrequency load shedding load.

COMMISSIONER CLODFELTER: While we're on this slide let me go ahead and ask the question, do you have any circuits that are exempt from load shed for the same reason Dominion does, because they're determined to be net positive generation?

MR. ROBERTS: So, we do it a little bit differently. Our script, our DM -- our distribution management system will actually look at the circuit and see at the point in time we're implementing the load shed if it's net positive. And if it is, it's

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foolish to shed it because it's helping, it's not hurting.

COMMISSIONER CLODFELTER: So, it's realtime?

MR. ROBERTS: Yes, that's correct.

COMMISSIONER CLODFELTER: Thanks.

MR. ROBERTS: So this slide represents our Grid Status Report. And this grid goes out to very broad communication to the Company with respect to providing an awareness, and that awareness is the expected level we're going to be in, grid status level we're going to be in for the next seven days. And in this case, this represents the January 17th through January 24th period of this year. And these grid status levels - green, yellow, orange, red, purple, black - they correlate directly with our load reduction plans. And so the operators and others that are involved in the general load reduction plan, reviews in training, they understand this correlation so they understand what the awareness is pointing to.

So, if they see a yellow, they know the situation is heightened a little bit. Maybe reserves are not going to be meeting the full need for daily day-ahead reserves; for example, the projections based on load and resources available. And so things that

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can happen under yellow is it can be communicated to the generators, you know, don't perform any discretionary maintenance, something that could risk availability of the generator.

And so that would help us preserve our capabilities to not get deeper into these, this color chart, or into orange, red or even worse purple where we have rotating outages. And this status report was implemented after the 2014 and 2015 cold weather events. And its sole purpose, once again, was to provide a heightened situational awareness and to be able to communicate effectively grid status. And once again, the purple status is where firm load shed would occur.

COMMISSIONER CLODFELTER: DEF, is that Florida?

MR. ROBERTS: Yes, that's correct. Yeah, so it covers all of our jurisdictions in one report.

COMMISSIONER CLODFELTER: Okay.

COMMISSIONER DUFFLEY: Mr. Roberts, can I ask a quick question about how you implement your firm load shed versus how Dominion implements it, going back to Commissioner Clodfelter's question. It sounds like with Dominion, they have prescriptive procedures

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and the operators follow. If you're in this bucket, you're going to be shed. That can be done very quickly, it sounds like.

You mentioned that ERCOT, things deteriorated very quickly and you educate your operators on that issue. But it sounds like Duke's procedure requires more discretion, right? So a circuit is not just within this certain bucket and it's going to be shed. You look, and is it just for that one category? I'm just wondering about when things start to deteriorate quickly, is there a more automatic, less discretionary procedure that you implement?

MR. ROBERTS: So, I'll try to describe it, and hopefully this will answer your question, Commissioner Duffley. So, within distribution, each of the circuits is categorized into one of these priorities. And there is a script that our distribution management system will run. And it will go through and it will do things like pop open reclosures on the circuit or breakers, and that will shed that circuit, and it does so automatically.

So, the way things would unfold is the ECC, the system operator, will realize something could be imminent or, you know, maybe we look at possibly needing it tomorrow morning. For example, based on forecast and resource availability, we will be communicating with the DCC.

If it's morning of, for example, similar to an ERCOT event, we will have communicated with the DCC already, but we will make another communication and say, "be ready to shed up to 1,000 MW of load", and so they'll be ready to shed up 1,000 MW of load with their DMS. All they have to do is plug in that number, hit a button, and boom, you implement that script to do those rotating outages in the DMS, and it's based on that prioritization that's preestablished with those circuits.

COMMISSIONER DUFFLEY: Okay. Thank you.

MR. ROBERTS: You're welcome.

So, the last set of questions are related to energy transfers and reserve sharing. So, I'll address the frequency drops first and go in kind of a reverse order. But with respect to frequency during cold weather events, it's really that having too much load for the generation. If you have a lot of entities that have that imbalance and that correction, you're going to take energy from the rotating masses

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and you're going to slow down the system it reflects in lower frequency. What you don't want to do is get anywhere close to this underfrequency load shedding level. The first level which is, like I said, for us 59.3 Hz.

And so we looked at the data that was available to us which was the January 7th, 2014 day and the lowest frequency that we saw during that day was 59.94 Hz. Well, that's well above the 59.3 Hz, which is your first level of underfrequency load shedding. The bottom line is --

CHAIR MITCHELL: Is that level the same for both DEC and DEP? It's not a system --

MR. ROBERTS: The 59.3 Hz?

CHAIR MITCHELL: Yes.

MR. ROBERTS: Yes, that's correct. Most of the eastern interconnection with the exception of something like Peninsula or Florida which has a little bit different stability concern has that same first level, 59.3 Hz.

With respect to transfer studies, Duke does participate in regional transfer studies and, also, we ran the study as recommended by the report -- transfer study by the report. It wasn't associated with any of

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these groups, but we did get a look at those transfers for high winter peak demand.

But with respect to regional transfer studies, the SERC Near-Term Working Group, we participate in that group that does transfer studies. The Long-Term Working Group, the Southeastern Reliability Transmission Planning Group, and the North Carolina Transmission Planning Collaborative all conduct transfer studies. And I'll have more on the transfers and transfer capability in response to your questions in the next couple of spots.

So this just looks at Texas, and the reason that they weren't able to leverage transfers to be able to avoid some of the rotating outages they have. They have 1,220 MW of DC tie capability, so they can import a little over 1,200 MW. About 400 of that, that ties with the Mexico area, were out and so they could only import 820 MW during that morning. So, that was their total import capability associated with the morning in which they started rotating outages.

Whereas, DEC and DEP, we have a little over 1,800 MW of import capability we use for capacity purchase, capacity purchases, for resource adequacy. And, in addition, we maintained around 1,000 MW, a

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little bit less in DEC, a little bit more in DEP, of transmission capacity to enable importing emergency energy from neighboring entities, and that's primarily if we lose a large resource on our system.

Also, when we purchase power, we make sure that we procure firm transmission service associated with that, importing that capacity. So, we make sure it's reliable. The only thing about purchase power, though, that I would like to highlight is it is usually non-dispatchable. And so looking forward, once again, to, you know, a world with a lot of renewables, a lot of variability, dispatchability is going to be very important with respect to managing that variability.

Also, I'd like to highlight that as we stated in the 2021 NCUC IRP Technical Conference, we do count on a little over 2,000 MW of non-firm assistance from neighbors in our resource adequacy studies for the winter peak, and that compares to the highest I've seen in -- you know, I have about 28 years in system operations experience -- and the highest I've seen is around 1,057 for DEC/DEP. And, of course, we haven't been merged for I guess about 10 years now. So, it's longer than I thought. But in

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that time I haven't seen anything over that 1,057 that we imported with non-firm assistance in February of 2015.

COMMISSIONER CLODFELTER: How does that 2,000 MW break down between the two Companies?

MR. ROBERTS: Yes, so DEC is around, if I remember correctly, around 800 and then DEC (sic) would be the remainder. So, it's 1,000 -- it averages about 1,000 each.

And that concludes my presentation and so we'll answer any further questions that the Commission may have.

CHAIR MITCHELL: Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Excuse me, gentlemen, it's going to be a little more disjointed because we've covered an awful lot of the questions, so it's going to take me awhile to hunt and peck through here to make sure I see which ones we haven't covered.

In the written responses that the Company filed, the Company stated it conducted a review of its gas supply systems and concluded there were no gaps. While it's comforting to hear that, but it's a fairly, shall we say, high level and generic thing. What

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would a gap look like? What were you looking for that you didn't find?

MR. ROBERTS: Do you want to -- you speak to that.

MR. McALLISTER: Yeah, I mean, I think we were just looking at the fuel supply, you know, and our suppliers number one. You know, we have ongoing conversations with Transco, Piedmont and the other LDC on preparedness.

One of the things we did after 2014, we increased the amount of firm supply that we buy to cover the combined cycles at 100 percent capacity. But I think we just did a review of our suppliers. We did a review of different scenarios with the pipelines and potential risk, you know, compressors going down, those sort of things, and I think that was kind of the high-level review we did.

COMMISSIONER CLODFELTER: Let me ask you a more specific question. And thank you for that. I just -- again, when you get an answer that's that general and it doesn't -- sometimes, as I say, it's comforting but it doesn't tell you a lot, so I just had to ask.

A more specific question, though, is -- and

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this relates to some information that was in a confidential exhibit you filed, so I'm going to try to ask it in a way that doesn't get into the confidential piece of the material. So, in the filing there was a statement that some of your gas-fired units that are on interruptible supply contracts have in the past experienced curtailment due to demand or cold weather of supply. And what jumped out at me was that one of those units was at one of your designated black start units. Do I understand that correctly that you have at least one of your black start, designated black start units is on an interruptible supply contract?

MR. McALLISTER: What response?

COMMISSIONER CLODFELTER: It was in response to Question 9. And again, I'm trying to ask it in such a way that I'm not getting into anything that's confidential.

MR. McALLISTER: You know, I would --

COMMISSIONER CLODFELTER: If you have any such units. Let's try to stay as far away as we can from confidentiality. If you have any such black start units that are on interruptible gas supply contracts, why is that? Is it because they're primarily oil burning in the first instance?

MR. McALLISTER: Well, we do have some black starts using oil only. And, like I said, there's no known specific unit. But the other thing is we typically don't buy interruptible supply, right. All of the gas we buy on a day-to-day basis or a season ahead is firm. I don't have a specific answer because, like I said, I'm not aware of any --

COMMISSIONER CLODFELTER: Yeah. It may --

MR. McALLISTER: It wouldn't have the capability to start a black start unit either on gas or on oil.

MR. ROBERTS: I'll just add in the DEP system we do have a black start unit that is dual fuel and it's primary fuel for black start is oil.

COMMISSIONER CLODFELTER: This may be the unit in question. I wonder if we could submit a question for a confidential late-filed answer to be sure that I'm understanding that the unit I'm looking at is the one you're thinking of.

MR. McALLISTER: Yeah. I think we're thinking of the same --

COMMISSIONER CLODFELTER: We can do that so we don't get into that here today. But that -- it struck me that you seemed to have one that might be on

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an interruptible supply contract. Thank you for that.

MR. McALLISTER: Well, one thing I will add, Commissioner, maybe they were talking about the redelivery contract that technically it's interruptible but it --

COMMISSIONER CLODFELTER: Okay.

MR. McALLISTER: It may be something different. So we'll give you a specific answer.

COMMISSIONER CLODFELTER: Okay. We'll frame the question and get it to your counsel in such a way that you can make a confidential filing in response so we can get clarification of that.

With respect to your dual fuel units, again, let me just confirm that, if I understood you in a response to an earlier question, that you test those units if you predict 15 days out an adverse, a weather unit, you can test the units then. Is that automatic or does that require some discretionary decision?

MR. ROBERTS: No, that's discretionary. The system operators would usually request such tests or the plant may decide to test in order to make sure there are no issues with running on fuel.

COMMISSIONER CLODFELTER: You do -- that prompts another question about the weather forecasting topic we were on. You do -- you had the ability to request plant-specific forecasts. As I read the written filings, though, it seemed like those were for purposes of managing the immediate weather conditions that might affect the plant operations themselves. Do you use those for purposes of system operations in an adverse weather event or they just like to make sure you know what the wind velocity is going to be at the Sutton plant when a hurricane comes? Is that the only purpose of those forecasts?

MR. ROBERTS: Right. If there is a significant cold weather event, especially one involving winter precip, we, the meteorology group can provide plant specific forecasts in that instance, and things like wind speed, wind direction will be --

COMMISSIONER CLODFELTER: Is that -- icing conditions, is that routinely done for all the plants or is that just on a -- who requests that?

MR. ROBERTS: It's usually done on an as-needed basis. And that may come out of something like our tailgate team meeting in that discussion with the -- since generation is represented, meteorology is there, system operations, fuels, all parties involved are in that discussion.

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COMMISSIONER CLODFELTER: It would be case-by-case?

MR. ROBERTS: Yes.

COMMISSIONER CLODFELTER: You might be getting ice in Asheville but you're only getting rain in Greensboro, so you would ask it for the Asheville plant but not for the Belews Creek plant?

MR. ROBERTS: Similar to hurricanes.

COMMISSIONER CLODFELTER: Okay. I got it. Thank you. Back on Question number 9 that I referred to in a minute, there was in the written response to that question, the Company provided a scenario that showed high renewables, high storage on the system and no coal units on the system against, meshed against the actual January events of -- January of 2018, and that filing showed an awful lot of unserved energy. And I'm just, I'm really curious about why you showed us that scenario? What were the drivers of showing that particular scenario?

MR. ROBERTS: Yeah, I mean, they're -- it does point to a couple of things. One is it highlights that Duke missed incorporating the potential for converting a dual fuel operating unit to forecast that could be a part of a plan in going

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forward. And if you add that one in it significantly -- and if you consider carrying forward the current capacity purchases we have, preserving those, you end up having practically no unserved energy in that scenario.

So those things can change, but the one thing I think it does highlight, Commissioner Clodfelter, is that we are going to need some high-capacity factor-type resources to replace our coal. I mean, it's just for reliability and maneuvering around renewables, and you can see in this case in the graph on Figure 4, it was decent solar performance. There were a couple of days where it was low output, but for the most part it was decent solar performance.

COMMISSIONER CLODFELTER: I thank you for that. It was a question of curiosity. I think you've satisfied my curiosity about why you showed us that scenario. I understand.

Back to the black start question. It really is -- let me just generalize the question. Can you provide a late-filed exhibit that shows, the question I was asking Dominion is, what's the technology configuration of each of those units? What type of

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unit is it? Is it an industrial frame CT and, if so, what class? Is it some other alternative to an industrial frame CT, and so forth?

Can you -- you've got an exhibit with all those units in it. Can we get a version of that that just shows us the type of technology platform that's being used on each unit?

MR. ROBERTS: Yeah, as far as identifying black start units, we'll probably have to provide something under seal.

COMMISSIONER CLODFELTER: That's fine. I would, if it needs to be under -- if it needs to be confidential, confidentiality is fine with me if it's fine, if my counsel says it's fine. So, we're good.

Again, we're jumping around a little bit. Again, because you've covered a lot of what I would have asked you about in your presentation. I asked Dominion a question, and I think you heard about what you're beginning to do or what you may be are in an advanced state of doing, about trying to figure out how to take battery storage especially and/or microgrid, and integrate those in your planning for those as responsive resources for an extreme weather event. Not in terms of normal grid operations but as

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responses to an extreme event. So, tell me where you are on that?

MR. ROBERTS: Yeah. So, there has been an area where -- and it's been associated with hurricane and shelter not a cold weather event, but being able to establish power from a local perspective. If its distribution fee were cut to that shelter to have power for people staying there with respect to being displaced from their homes during a hurricane, we have looked at that scenario and think we've implemented something in that line. So, in a broad scale, and this is subject to check, I don't think we've looked at an extensive use of microgrids on the system. With respect to batteries, this was the case by the way with this shelter, was the case of battery application.

With respect to the application of batteries, I mean, you're looking at peaking capacity; you're looking at regulation; you're looking at potentially supplying contingency reserve. There's multiple uses associated with battery storage.

The one thing that we are looking at closely going forward is you have multiple types of resources shaving/flattening that peak with respect to demand-side management, DRE, and then two-hour storage flattens it a little bit more. Then you get to two-hour storage doesn't work anymore and you have to have four-hour storage or you have to have six-hour storage in order to keep flattening that peak, lowering that peak value. So that is one of the things we're looking at with respect to application of battery storage. We can't just have a bunch of two-hour batteries and significantly lower the winter peak.

COMMISSIONER CLODFELTER: Well, the things you described though seem to me to be related to what I call "a normal grid operating environment". And I was really curious about whether you have been thinking any about special uses in special operational situations as you might run into a few and try to use battery storage to respond to an extreme weather event?

MR. ROBERTS: Yeah. I mean, it's part of like an uninterruptible power supply type of approach. I don't recall any conversations that I've been involved in. And very probably other people in Duke associated with business development with batteries and so forth are looking at those applications.

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COMMISSIONER CLODFELTER: It strikes me that operationally, though, you would have to look at a battery very differently, because you wouldn't want to be you've got a cold January morning, that's the day before an ice storm, and you don't want to be discharging that battery on that normal cold morning because you're going to need it to be charging that day so you can maintain it for the next day's ice storm. So, I was thinking that there might be operational differences in how you looked at battery as a resource when you're using it to manage extreme weather and how that would affect your planning and your operational decisions.

MR. ROBERTS: Yeah, I mean, as far as utilizing the capability of the battery to preserve reliability, we will definitely look at preserving that charge state for things like fuel management, things like making sure we can serve really high peak demand over a certain period of days or hours. I mean, from an operations perspective, that's the best answer I can provide.

COMMISSIONER CLODFELTER: That's fine. It was kind of a blue-sky question. As I told the Dominion folks, I just wanted to see where you were in

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thinking about that kind of blue-sky question.

On communications with customers, you heard some of the questions I was asking Dominion and the question that Commissioner Gray asked Dominion, and thank you for the materials that were in the written filings about the communications with customers.

One of the things I was interested in in my questioning, and I didn't see it in the Duke materials, is what kinds of communications you're having with customers about the things they need to be doing on their side of the event. Things to protect themselves - safety issues, operational issues about equipment or devices. What types of communications are you doing with customers on those subjects?

MR. ROBERTS: Yeah, it's similar to what Dominion stated with respect to things you can do to keep heat in home, turn down your thermostat, you know, so that you don't have it on 75 degrees, you know, during the cold winter weather. But also, I mean if we were to see a potential for rotating outages, we'll definitely communicate that potential so that customers are aware of that and plan accordingly.

COMMISSIONER CLODFELTER: Do you have the ability to tell the customer you're up 15 minutes from now?

MR. ROBERTS: Not that I'm aware of, sir.

COMMISSIONER CLODFELTER: Same as Dominion. Your situation is exactly the same as Dominion? No different?

MR. ROBERTS: Right. And really that slide on the urgency or the rapid pace at which firm load shed can occur, that sort of inhibits the ability to communicate with that customer on that frequency.

COMMISSIONER CLODFELTER: With respect to the other communications, you were referring to what you tell customers to do to protect themselves and to protect their devices and equipment. Those were not in your written materials, that's why I ask about them. Are they in written form and can we just get those so we fill out the record and have everything?

MR. ROBERTS: Yes. I think one of the communications, the diagrams, if I remember correctly showed how do you prepare.

COMMISSIONER CLODFELTER: Yeah.

MR. ROBERTS: And so there's some underlying messages associated with that, how do you prepare. We can provide that.

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COMMISSIONER CLODFELTER: That's it for the start.

CHAIR MITCHELL: Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: So, I have just one, well, just one question. In the questions to the gas utilities -- just a second. One of the questions was how do your utility's gas curtailment emergency plans account for electric generators that rely on gas and do you communicate with them as to whether they are able to switch to an alternate fuel or whether they have alternative sources of generation available? And Piedmont responded that each generator follows their own internal protocols for using alternate fuel and enroll in reserve dispatch or other means to maintain grid resiliency.

Could you walk us through the Duke protocols and give us an explanation?

MR. ROBERTS: Yes. I think you're referring to gas management facilities, like compressor stations; is that correct?

COMMISSIONER BROWN-BLAND: In terms of their curtailment plans, we were asking the gas companies --

MR. ROBERTS: Oh, okay.

COMMISSIONER BROWN-BLAND: -- how they do it

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when they curtail. And so we were asking do they communicate and having interactions over, you know, what alternate fuels are available to the electric generator.

MR. ROBERTS: So, I'll let my colleague Joe answer.

MR. McALLISTER: Yeah, I think, if I'm understanding your question right, what we do every day and during cold weather, we send -- and I'll just use Piedmont as an example, we send them an hourly by plant gas plant profile. So they know every day what, by hour, which plants we think we're going to bring gas. Now, what they may not always know in detail is which ones have backup fuel. For how -- you know, Dominion was talking about how you may have to, based on economics, you may actually run a dual fuel CT on oil and gas. But the information that Piedmont gets from us would show our actual gas profile by hour for today and the next seven days.

In terms of how we dispatch certain units, whether it's economic or we're trying to manage gas supply and how we switch that, they probably wouldn't have the ins and outs of that. And I think that's what their question is saying, is that we may switch.

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You know, we may have a certain plant on a system like Wayne County that in the winter primarily runs on an alt so they're familiar with that, but they may not -- they may not know precisely the reasons why we switch but they do know, they do have a profile of which units are going to burn gas and how much we think they're going to burn by hour.

COMMISSIONER BROWN-BLAND: So, how do you go about doing -- you know, what's your protocol for the decisions you make regarding use of the alternate fuels?

MR. McALLISTER: Yes, so we'll take our unit commitment plan for any given day and we'll look at our fuel supply contract from the gas side, right. So, when Sammy was -- the one slide when we were talking about coordinating, you know, we do set up going into the winter with very broad burn ranges, right, we don't wait for an event to happen. So the decisions we make sometimes are economic, you know, like today gas is $8.00, oil was effectively $29.00, so there's no gas constraints. It's not cold. We'll run gas ahead of oil.

Now, if you get to certain load levels, there may be certain units just because you reach a

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certain threshold, because we do have dual flexibility at CTs we'll run those units on oil. Because, one, we've used all of our gas contracts and now what we have left is oil. So, those decisions are both economic and, kind a, our fuel supply portfolio, but they're typically economic. But, for reliability, there are certain units we will run on oil that are dual fuel capable based on the contract portfolio we have on the gas side.

COMMISSIONER BROWN-BLAND: And some of those decisions, you know, by some sort of set standard or is it a lot of realtime discretion --

MR. McALLISTER: No, it's planned ahead. I mean, like I say, we don't typically do things like switch on a fly. I think, once again, we produce a unit commitment plan that includes a load forecast. It includes our resource plan for the next seven days. So we run the model, we stack our generation availability, our power purchases to our load and we try to do it in the most economical way and sometimes that means we run oil.

You know, you've seen really high prices in the Carolinas and sometimes we do it because we're running every unit that can run and some of them can

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only run oil. So, those are stages that's very structured. It's very production cost model-driven, and it includes all the inputs for the generation, it includes the load and it includes the economics, and in some cases we're just running -- we've hit that point where we're just running oil in our units.

So it's a very structured, robust process. Just like the load forecast, we're running production cost models. On a normal day, a couple times a day, and then during extreme peaks, we're rerunning these 7-day resource plans, you know, three and four times. So it's very -- a robust process about how we do that. And then the fuel team's involved, you know, the power trading team's involved, so it's -- I think that was kind of the idea, that slide. In those robust peak days, you're making choices, all right, on which units may run on gas or oil, when you're on the top of the stack.

COMMISSIONER BROWN-BLAND: All right. Thank you.

CHAIR MITCHELL: Commissioner Hughes.

COMMISSIONER HUGHES: Thank you. Could you just talk a little bit about some of the traditional reliability metrics you use and how this whole

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conversation today kind of fits into those? So by that, I mean, you know, it's all about mitigation of risks, so the idea is everything you're doing is still going to lead to some risk. And, you know, how do you -- should we -- how do you think about/how should we think about that risk?

Is it some number in some other number of years to have a curtailment? You know, what's the metrics you talk about behind the, kind of, screens, and then has that number changed since you've been doing everything that we've been talking about for the last, you know, two hours? So was it at one time more frequent? And now that you've managed to do all of this, we're looking at a better number? Does that make sense, that question?

MR. ROBERTS: Yes. Thank you. So for resource adequacy, the traditional metric has been for, you know, studying. Do you have an adequate portfolio to meet your resource adequacy.

COMMISSIONER HUGHES: Sure.

MR. ROBERTS: It's been a one day and 10-year loss-to-load expectation. There are a lot of groups now precipitated by this 2021 ERCOT event that are looking beyond one day and 10-year loss-to-load

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expectation, and so they're looking at energy sufficiency. And, you know, that energy sufficiency, not all is electrons but it's also molecules. And so there's a lot of, you know, subject matter experts that are discussing coming up with new, reliability metrics going forward that will be needed when you start looking at power renewable portfolios and all of the carbon reduction plans that are occurring. And some of the groups involved, just giving you an idea of the think tanks involved for every NERC, and then a lot of the industry representatives.

COMMISSIONER HUGHES: So I'm still -- I'm still trying to wrap my head around. So that -- right now, we have this existing metric that lots of people have, kind of, concerns about. With your modeling and everything you're doing, are you -- you've just done so much. You've spent so much money. Is there modeling behind the scenes that it's gotten us somewhere else or is there not that -- is there not that quanti -- you know, is there that quantitative, sort of, risk analysis behind the scene?

MR. ROBERTS: Yeah. Maybe as far as from a risk perspective, I mean, there are metrics we track, like starting reliability and EFOR, traditional, CADs,

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metrics and unit performance metrics that we consider with respect to ensuring reliability of our portfolio resources.

MR. McALLISTER: You know, one thing I'll ask, Commissioner Hughes, is you talk about the modeling into the future. Yes, there is -- you know, I wouldn't say it's complete, but, you know, things like, you know, system ramper rig, (sic) right, things that are traditional when you think about reliability metrics as reserve margin. How fast does the system need to move up and down. So, you know, ramp rates of the system aligned with the new, you know, portfolio that's setting it out there that it might have a lot of renewals, right, so there are other metrics.

I don't they're fully based, like Sammy said, but there's definitely things from a day-to-day management that in the future, as you add more renewables, as you remove, you know, large supercritical co-plants, as you transition, there are other metrics that I think are in the thought process. Now precisely what all those would be, I think it's still a work in progress, but I think that is somewhat what Sammy's talked about. It's just not reserve margin anymore. It's the ability for their system to

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ramp. You know, how do you plan for that. What kind of resources do you need, etc.

COMMISSIONER HUGHES: Okay. I appreciate this, and I realize a lot of this is discussion. It's probably more suited to a reserve discussion, but just the other side of this question is, there's a cost associated with all this risk and mitigation. And you've talked about things that you've done, going from interruptible to firm. A lot of these measures have cost, and I'm just curious where's the kind of risk versus cost modeling going on. You know, is there -- because the public really wants no risk, I think, but we all are operating under this risk.

So I'm curious, you know, what kind of level of cost or -- and how are you modeling it. So if you can tell us that -- you know, back to your chart where you're showing curtailments or using the 1 in 10 years, how are you modeling how you could get that lower, you know, and how the cost is. Is that kind of sophisticated economic modeling going on or are we -- does that make sense?

MR. ROBERTS: Right. I mean, the resource adequacy studies that come up with her planning reserved margin, and then under a least cost manner,

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there may be other requirements. But under a least cost manner, providing that resource portfolio that meets that planning or reserve margin, that's her resource planning direction right now. But like I said, I think you will see some changes over the next few years with respect to the results some of these groups are doing.

COMMISSIONER HUGHES: Okay. So it's just really all she did in that existing model. There's not something else related to Texas that showed, okay, maybe that model's not going to work.

MR. ROBERTS: There's data analytics that are being done that look at the Stochastic models so you get a -- you know, you're looking at a lot of scenarios and, you know, what gives you certain a confidence interval associated with all the scenarios from a portfolio. And like Joe said, there's ramping, net ramping, net-to-van (sic) ramping, excess energy.

COMMISSIONER HUGHES: Okay.

MR. ROBERTS: You know, those sorts of things you have to look at as well with respect to reliability of your portfolios.

COMMISSIONER HUGHES: And I realize from the staff, in looking back, that they're going to come

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back to me afterwards and explain a lot more of the details of how this is done. So we don't have to go any further, and I understand it's not so simple. It's just we talk about reserve is the only metric and when we have those discussions that you've been laying out all these other things that you've been doing that costs money, that are reducing risk, and I just didn't know what kind of, you know, risk analysis, if there was some new form of risk analysis.

There's another question, and hopefully it's a much easier, quicker question, is with the integration of your control of meters, both at the residential and non-residential that's occurred over the last four or five years, I don't think we've heard anything about how that might have changed. I mean, you didn't have that, I think, in the Polar Vortex. Now, you know, you can cut my meter off at home, I think, fairly easily. Is there any thought or any use of that kind of capacity in tandem with the more traditional cutting the circuits off, you know, or is it -- what is that? Has that done anything for us in this whole area that we're discussing?

MR. ROBERTS: Yeah. I think we continue to look at ways to shake customer demand to provide us an

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advantage or give us some leverage associated with meeting winter peaks, and I think you'll see that continue to go forward with respect to leveraging Demandside Management and demand response tools, E, with respect to helping with shaking that demand. And that should support -- be supported with cost justification.

COMMISSIONER HUGHES: So you're not going to get to where there's a block and there's one person on some medical device and everybody else gets cut, but they still have electricity. So it's like that kind of pinpointing using -- it just is not typically feasible?

MR. ROBERTS: I mean, right now, I would say that that process is more manual. I remember in discussions with these significant winter peaks. You do have customers that can sign up for this special medical need. And, you know, those receive a higher priority with respect to ensuring their welfare.

COMMISSIONER HUGHES: Okay. So I should move next to either a hospital -- an active solar facility or someone with a dialysis machine in their house, and I'll --

MR.ROBERTS: One way or another --

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COMMISSIONER HUGHES: Okay.

MR. ROBERTS: -- we will balance resources and demand.

CHAIR MITCHELL: All right. Commissioner Duffley.

COMMISSIONER DUFFLEY: Thank you for letting me jump ahead, Commissioner Brown-Bland. My question relates a little bit on that discussion. You probably heard earlier this morning the discussion with Dominion about their last load shed event in 1994. When was the last load shed event in the Carolinas?

MR. ROBERTS: To my knowledge, Commissioner Duffley, we've never had a load shed event.

COMMISSIONER DUFFLEY: Okay. And have you ever called for voluntary reductions or use the voltage reduction mechanism --

MR. ROBERTS: Yes.

COMMISSIONER DUFFLEY: -- in times of systems stress?

MR. ROBERTS: Yes, so both. We've actually had customer repeals to reduce load to conserve, and we've also implemented our 5 percent emergency voltage reduction over three of those 2014 through 2018 winter peaks.

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COMMISSIONER DUFFLEY: And that --

MR. ROBERTS: Subject to check.

COMMISSIONER DUFFLEY: And that ability is in both DEC and the voltage reduction?

MR. ROBERTS: So with the implementation of the DMS and the implementation going forward of IVVC, we will have a more automative means of doing that. In DEC, currently, it's more manual means to 5 percent voltage. But yes, we can implement 5 percent voltage reduction in DEC and DEP.

COMMISSIONER DUFFLEY: And a subjective question. Have both of those mechanisms -- like how effective are both of those mechanisms?

MR. ROBERTS: So I can just speak to DEP experience since I was managing that control room for a while with respect to these cold winter events. And the 5 percent voltage reduction, if I remember correctly with the 2018 peaks, we reduced by around 250 megawatts, if I remember correctly, subject to check.

COMMISSIONER DUFFLEY: Thank you.

MR. McALLISTER: You're welcome.

COMMISSIONER BROWN-BLAND: I have one more for you. Am I right that Duke has said that all of

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its gas contracts were for firm delivery of gas?

MR. McALLISTER: That's correct.

COMMISSIONER BROWN-BLAND: And do you mean that with respect -- does that only apply with respect to those facilities that are 100 percent gas burning or does that still apply where there's dual fuel, like coal-fire and of coal?

MR. McALLISTER: Yes. So let me give you a little bit of context. So when we say firm delivery of gas, we have a portfolio of contracts. We might have firm transportation that we acquire from the pipeline. We may go out and acquire additional transportation from other providers, and we may buy delivered firm gas. So a lot of the gas we're buying is actually purchased -- all of it is purchased on Transco, somewhere on Transco.

What we do then is we deliver that gas, and I'll use Piedmont as an example. We have that gas delivered to certain points into Piedmont system, and then they redeliver it under the firm transportation contracts that we have to get there. So when we talk about, you know, firm supply, we're really talking about gas that ultimately -- whether we transport it or buying it from other people who have firm

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transportation into the points, into the -- you know, whether it's Piedmont's system or into PSNC's system, and then they redeliver that gas to the actual plant facility. So the gas is brought upstream and then moved by Transco and then moved on the local distribution companies to the specific plants. But when we say -- you know, we expect and we buy firm delivered gas under our agreements for this supply.

COMMISSIONER BROWN-BLAND: So in the case where it's dual use or coal-firing, you don't use --

MR. McALLISTER: Yeah, but looking at it --

COMMISSIONER BROWN-BLAND: You still don't use --

MR. McALLISTER: On a system --

COMMISSIONER BROWN-BLAND: You still don't use an interruptible mechanism or --

MR. McALLISTER: No. I think we managed the total -- for example, we look at tomorrow. We already have contracts in place, right? So, you know, Commissioner Hughes was talking about some of the models we use. You know, we don't set up just for, kind of, an average firm rate. We have contractual portfolios in blocks. So blocks for combined cycles, blocks that we can call on daily. But I guess what

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we're saying is we buy to that amount for the system, right. And then behind that number, we talked earlier about the production cost models. It's producing a fuel forecast that were managing what we need for tomorrow based on the contracts we have to kind of align with that fuel burn forecast.

And then as Dominion was talking about, there might be some operational considerations. There might be operational considerations. All those things were taken into account, but yet we're buying to a forecast that is produced from a production cost model, and we have a contract portfolio that some of them are buying for the month, some of them are buying for day-to-day under firm contracts. But I think the point is we buy everything under firm contracts, regardless of the duration of the supply that we're buying, if that makes sense.

COMMISSIONER BROWN-BLAND: I'm not sure, but we'll think about it. Thank you.

CHAIR MITCHELL: Just following up there, so there's never been a situation where either of the companies hasn't been able to get gas to a power generating unit because delivery to that unit has been interrupted?

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MR. McALLISTER: Not to my knowledge, right. If we have secured the gas and got it on the Piedmont system, I'm not aware. For example, using Piedmont or PSNC, I'm not aware of any specific things. Now, from time to time, you have little adjustments that you make when you buy a lot of gas. You might have little minor adjustments on the supply side where you have little cuts here and there, but they're highly immaterial, and we usually correct those through the nomination cycle that we go through. But yeah, and not to my knowledge. Once we've gotten the gas on Piedmont system, that we couldn't redeliver it to an actual power plant.

CHAIR MITCHELL: Okay. A couple of questions for y'all on the VACAR arrangement. Does -- first, Mr. Roberts, what does Dominion's intent to withdraw from the VACAR reserve sharing arrangement mean to you?

MR. ROBERTS: Yes. So like Mr. Bielak was speaking to earlier, the transmission capability will still be there on an interface and we'll still have the capability to call PJM for emergency energy. I mean, it won't be part of the VACAR RSG, but we'll still be able to call PJM and request emergency

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energy.

CHAIR MITCHELL: So do you have the confidence that when you make that call, there will be a transmission capacity available to get the emergency energy down here?

MR. ROBERTS: Yeah. So based on looking at the TRM IDs and the OASIS and also per --

CHAIR MITCHELL: Transition Reserve Margin.

MR. ROBERTS: Yes.

CHAIR MITCHELL: Is that what TRM -- okay.

MR. ROBERTS: Yes. And based on the comments that Mr. Bielak made, yes.

CHAIR MITCHELL: Okay. Does Duke plan to make any changes to its TRM as a result of Dominion's withdrawal?

MR. ROBERTS: Yeah. We will still plan for the TRM in accordance with our TRM ID as posted on our Oasis, and there's certain requirements around what has to be in that TRM. You have to able to handle the in-rush when you lose a large unit, and so if the space is there for that in-rush, the space should be there for continuing to bring in emergency energy.

CHAIR MITCHELL: So just to make sure I understand this correctly, so the TRM really is

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predicated on the units on your system, and one of those going down?

MR. ROBERTS: It's -- it's tough to explain without getting in too deep into the wheat, but -- yeah. It's predicated on loss of units, and it can be different units that affect interfaces differently. And the same thing with other entities. They look at loss of large units on their system and see how that affects the interfaces, if they're looking at, you know, the power close resulting across that interface from that loss of unit.

CHAIR MITCHELL: Okay. So does Dominion's future exit from the VACAR arrangement affect Duke's preparations for cold weather events in any way?

MR. ROBERTS: Yeah. I mean, well -- so currently for cold weather events, and this was something adopted after the 2014 Polar Vortex, we would have VACAR call with the members. We moved it to 6:00 in the morning, because if you wait until 8:30, it's too late. And so we had a call with those members. So I would foresee us continuing to invite PJM to that call just to see what their state is with respect to generation and, you know, what they're expecting with respect to power close capability,

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rider emergency assistance. And so I would see us continuing to invite PJM to that call.

CHAIR MITCHELL: Commissioner Duffley.

COMMISSIONER DUFFLEY: I have a follow-up. I heard that there was no concern regarding available transmission, but is there any concern about PJM's ability to actually have the energy necessary to transfer during these times of system stress?

MR. ROBERTS: Yeah. I mean, there's that concern with the VACAR RSG. I mean, a VACAR member can call the other VACAR members and notify them that they are not maintaining their reserves because they're out. And I know of a similar situation that occurred in 2014 with a couple other VACAR members.

COMMISSIONER DUFFLEY: Okay. Thank you.

COMMISSIONER McKISSICK: One quick question. In follow-up to what Commissioner Brown-Bland was asking earlier about the firm contracts for gas, now when I think of a firm contract, I'm thinking of one that's for a fixed quantity at a fixed price. Are there times when it's not at a fixed price considering the volatility of the price of gas, it's fixed for a fixed quantity, it's guaranteed to be delivered? How does that work?

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MR. McALLISTER: Yes, you're correct. Sometimes, a firm contract can be -- you know, typically, it can be at a fixed price --

COMMISSIONER McKISSICK: Yeah.

MR. ROBERTS: -- or if we're buying under a firm contract day-to-day, it will be at the spot price. So yeah, it can -- you know, you can buy a monthly gas, and I'm just going to make up a number. That's $6.00.

COMMISSIONER McKISSICK: Sure.

MR. McALLISTER: And you set up your contract for it, and then day-to-day based on changes in load, changes in forecasts as CT runs. We also have firm contracts to buy, deliver daily gas. Now, that gas, the gas price is $10.00 that day, that's what you're going to pay. So yeah, there is a -- some of it is priced day-to-day based on the type of firm contract you have.

COMMISSIONER McKISSICK: Got it. And in terms of the oil, I know you spoke earlier about the volatility -- well, basically the oil being available when you needed it. But I'm just curious in terms of what the average ratio might be, and it may be plant specific or site specific between running on say oil

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or gas, as the case may be. How much more are you spending? Yeah.

MR. McALLISTER: Yeah. So I would say, you know, typically we're going to run economically, so whichever --

COMMISSIONER McKISSICK: Yeah.

MR. McALLISTER: Like, you know, we have to run CTs today. And let's just say the gas price is $7.50. The equivalent oil price is 28 or $29, so we're always going to try to run economically in normal kind of operations. But when you do get to these higher loads, the only unit you may have left may be oil units or you're running oil, or because you have a gas portfolio where, you know, maybe your load is so high for a couple of days, you decide -- you know, you don't want to have the ability to get more gas --

COMMISSIONER McKISSICK: Right.

MR. McALLISTER: -- from what you've already got. You may run other dual units on oil because that's all you have.

COMMISSIONER McKISSICK: Exactly.

MR. McALLISTER: So I think of a -- generally, we try to do it economically but certainly

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in extreme days, you know, based on, you know, can you buy a little more spot gas even though if it's cheaper than oil. Maybe you can, maybe you can't, but you'll run oil on those days, which is -- like Sammy was saying earlier, I mean, we have a lot of units that are dual fuel, so it gives us a lot of flexibility --

COMMISSIONER McKISSICK: Exactly.

MR. McALLISTER: -- during those colder periods to manage economically, and I believe from a fuel supplier perspective.

COMMISSIONER McKISSICK: Sure. I appreciate your presentation. It was insightful. Being most of the questions that were in the back of my mind, they got asked at some point by one of my fellow Commmissioners.

CHAIR MITCHELL: All right. Public Staff, you're up.

MR. METZ: Good afternoon. My name is Dustin Metz with the Public Staff. How are you gentlemen doing today?

MR. ROBERTS: Doing well.

MR. METZ: The Public Staff sent some discovery questions on March 25th. I'd like to turn to your responses to question 3B. I believe it's on

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page 5. And in that response, you have a general discussion on actions 1 through 3. Could you provide a general update by each action item where Duke is at the implementation process?

MR. ROBERTS: Okay. Let me read through these. And you just to clarify, you said 3B as in Bravo?

MR. METZ: That is correct, B as in Bravo.

MR. ROBERTS: Okay. Just to make sure I'm clear, Mr. Metz, so the action item that you're referring to are for the Companies' mission, critical nuclear, non-nuclear generating units, the Companies ensure the planned outages occur in over several months.

MR. METZ: That is correct.

MR. ROBERTS: So the only -- no, I'm not familiar with the current status. But the only thing I can state with respect to action two is that we do have the guidance document in place per quarterly testing of CTs and annual testing of CTs associated with CCs with the running on fuel.

MR. METZ: Would the Company be willing to file a late-filed exhibit with a general update or an implementation plan of each one of these action items?

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Just for context, these three additional cold weather actions are the result of filing the 2021 Texas event, and that we've had some discussions where some of these are in process. I'm just curious of where we're at in the overall planning or implementation.

MR. ROBERTS: Yeah. We would be willing to file a general status, general statement of status.

MR. METZ: Thank you. And in response to Question Number 8, the Company discussed the meteorologist from 2015 and 2018 winter events. And this question's not meant to imply one utility did bad or worse better than the other, but it appears that there were not events for the DEC plants but there were about a half a dozen events for the DEP plants. Do you have any insight into why the -- why no events occurred with the DEC and why events occurred at the DEP plants?

MR. ROBERTS: I do not have any insights on why was outages occurred at the DEP plants, because at the time, I believe in 2015, and I'm pretty confident in 2018, we had one VP over the gas fleet and one VP over the coal fleet.

MR. METZ: So would the Company be willing to file a late-filed exhibit to the extent you can

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look into or maybe explain why? And it could be nothing the reason why DEC plants had none and DEP did have some. Again, thinking out loud was oil -- DEC plants are closer to the mountains and some of the plants that were impacted were further down the southeast. It could have just been as simple as a temperature rating and we weren't expecting these temperatures down in this part of the area, but now it's been corrected.

MR. ROBERTS: Right. It -- I could have been associated with the day and the temperatures, because I know in 2018, for example, on the 7th, which was a Sunday, we almost hit our all-time peak on a Sunday. You still had snow on the ground from Raleigh eastward, and so you had a lot of heat that wasn't absorbed by the earth, so a lot of that was reflected and back up into the atmosphere. So your actual coldest temperatures were in eastern North Carolina that morning, and so that may have been a cause. I'm not sure. I would have to look into that.

MR. METZ: Okay. Thank you. Following on the Company's response to question number 8C as in Charlie regarding the load forecasts, you lowered the temperatures. When you lowered the temperatures, you

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reported a peak load of 43 gigawatts occurring across the Carolinas. Do you know offhand or would you be able to file as a late-filed exhibit the potential reserve margin or/and list the assumptions of any unit outages that did occur in that analysis?

MR. ROBERTS: Okay. Once again for clarification, is that 9C, Charlie? 9 Charlie?

MR. METZ: I believe it was 8 Charlie, but one second. Oh, you're correct. That is 9 Charlie.

MR. ROBERTS: Okay. Right. So based on looking at prior actual loads versus temperatures for cold winter peaks, this peak load that was forecasted, looking at these extreme cold temperatures, looks reasonable with respect to -- if you kind of extrapolated that line on out from past actual temperatures versus cold weather. So the 43 gigawatts protected for BA load, that looks extremely reasonable with respect to the temperatures.

MR. METZ: And the highest peak that we've had combined, I believe what you stated earlier was in 2018?

MR. ROBERTS: That's correct, at 36865 I believe was the number.

MR. METZ: And just in follow-up, the 43

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gigawatts that you're reporting here, you noted no unit outages and you're able to meet demand?

MR. ROBERTS: So this is looking at the stability of the load forecast model. We interpret it, the question that way, is does your load forecast look like it erratically predicts something that could cause a significant load forecast area that could jeopardize reliability.

MR. METZ: Okay. Thank you. Mr. Hinton.

MR. HINTON: Bob Hinton, Public Staff, and I just have a couple questions. Again, going to weather load forecasting and particular items -- questions 4 and 5 from the Commission and followed up with Commission's questions 6 and 7 from the Public Staff data request, so going to question 4 of the Commission, you note that weather forecasting load during extreme weather can be challenging and it's difficult enough just to forecast weather, but you appear to be doing a very good job at forecasting weather, and I expect that's the case.

So you talked about the difficulty of taking a weather forecast and translating that into a load forecast, which is ultimately what forecasting generates. And you've got tools which you've gotten

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and they look like they're reasonable tools for reasonable forecasts here. And kind of following that, I wanted to dig a little deeper in my follow-up question, follow-up with question number 6 in particular about the load response model.

Given this data from January, 2019, and I looked at the weather data for that, in particular for DEP's system and you've got data here for DEC, but I think a weather response was probably comparable, that was a mild month, I believe. And you can look at the chart and see that the most extreme temperature was 20 degrees. So that's not what I believe you define as extreme weather in that. Correct, right?

MR. McALLISTER: Yeah, I would agree with that.

MR. HINTON: So again, filing this late-filed exhibit thinking, could you maybe provide more of this temperature load graphs and maybe following an analysis that may kind of focus on how we translate a temperature that's like 10 degrees or an extreme temperature into an actual load? Because, I mean, back in the day when I actually loaded forecast myself for your company years ago, we thought there was a co-linear relationship. And if you look at a

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plot, you just kind of assume it's a linear relationship, but there's often a kink in there. And, you know, having discussions with Glen Snider with your load forecasting, you know, he's always talking about, you know, heat pumps have a certain point where they top out and then people rush out and buy portable ceramic heaters, and all of a sudden, the temperature load response grows. So if you can supplement that, I appreciate it.

MR. McALLISTER: Would you -- I mean, do you want a different -- do you want a month that looks -- I mean, is there some -- I mean, I guess we can talk about -- maybe this wasn't -- I think we had a little -- when we answered this, we were just trying to -- I think the point was we were trying to show that -- just what you said. Temperature and load aren't always -- you know, it's not necessarily linear, right, which there's other factors. But if there's a different month or a different period, you want to see a higher load?

MR. HINTON: Yeah, I want 2018 and 2014 and 2015, because, I mean, I've got a temperature or your system average temperature in '14 was a little less than 11 degrees. And on that day, your load was

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extremely high. You activated all the DSM you had, including large load curtailment. Yeah. You came very close to having a brownout, but you -- because the temperature was so extreme.

MR. McALLISTER: You want it for both, for January of '18?

MR. HINTON: To be honest with you, I'd like it for both because there's an early offset I made in the years past. The DEC has a lot of natural gas heating customers, where DEP has limited gas saturation, a little less gas saturation of natural gas furnaces. So there's more of a heat pump, furnacing heating needs in DEP's territory, so you have a different reaction to temperatures. And those heat pumps top out and people are so cold, and they rush to Walmart or whatever.

MR. McALLISTER: Yeah.

MR. HINTON: So I appreciate that.

MR. McALLISTER: Well, let me be clear. So you wanted January of '18. And was there another one you wanted?

MR. HINTON: Just January of '14 and '15.

MR. McALLISTER: January, '14, February of '15 --

MR. HINTON: Yeah.

MR. McALLISTER: -- and January of '18.

MR. HINTON: Months when you had extreme loads and extreme temperatures.

MR. McALLISTER: Okay.

MR. HINTON: Now, I think those three come to mind. And like you said, you have a lot of serious people that studied this particular area for the load forecasting. The other question I've got is -- let's see. You save the load models -- and I'm really responding again, going back to Commission question -- let me get my Commission question correct. Your data response, I think, to Public Staff data request -- no, no. Forgive me. One second. No. It was the Commission's -- response to Commission 4. You said the load models below recorded temperature of frost 30 years would not jeopardize reliability, and you've already touched on that with the last question by Mr. Metz.

The question I would ask is if you would look at your load models for an extreme temperature, like below 10 degrees, but use your simulation models and actually give more of an example of how a load -- how you'd be able to supply that if you had a Texas

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event, with those temperatures, both with a simulated scenario where you have forced outages.

Now, you have lots of forced outages during the 2014 and 2015 vortex, and you've done some hardening since then. And your system's much more, I think, resistant to cold extremes, and that's good, of course, but if you could do a scenario where you tested the reliability under extreme temperatures under a scenario or simulation or a reasonable simulation where you had forced outages that were reasonable to expect during a cold event.

Because, again, you answered the question that we're not -- your current studies and your current models would not jeopardize or would not -- your words are would not compromise the reliability of the system. And -- but that's not assuming the forced outages as you were -- you earlier addressed, but I think it's a core Commission question whether an extreme temperature which would result in a high load, the danger of reliability that's maybe more limited to the simple reserve margins, say, which of course goes to those issues.

MR. McALLISTER: Right.

MR. HINTON: If you'd consider that, if

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that's possible. The Public Staff would appreciate that.

MR. ROBERTS: Okay.

MR. HINTON: That's all I have to say.

MS. EDMONDSON: You have one more question?

MR. METZ: Yes. There's been some conversations of sort of spending reserves. So for context, because your memory is outstanding, Mr. Roberts, for like the 2014 or 2015 event, do you know or are you able to provide a general graph of showing the amount of spending reserves not synced to the grid on each hour for that given day?

MR. ROBERTS: That would be difficult, because for 2014 and 2015, because I would use energy accounting data for that, and I think as we stated with respect to looking at the frequency drops, we were lucky to find an Excel spread sheet where we had captured frequency data for the January 7th, 2014 date, but the data resides on magnetic disks and we don't have anyone with the expertise that can download that data.

MR. METZ: All right. So maybe I'll ask it a little bit differently. Generally speaking, from a system operations standpoint, how much spending

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reserves non-synced to the grid would you have running to have, is in my words, sort of in your back pocket to respond in a system emergency or a system event?

MR. ROBERTS: Right. So with the standards as they apply today with Bal, if you're in an EEA -- it's my understanding if you're in an EEA, you can utilize all your contingency reserves prior to shedding firm load. Now, as far as Bal 1 goes, you have to shed load prior to getting to that 30 minute -- 30 consecutive minute mark for your -- below your balancing authority ace limit. And so we would have to have the regulating reserve -- and this is how our resource adequacy study works. You would have to have the regulating reserve to make sure you could comply with Bal 1.

MR. METZ: And can you define contingency reserves?

MR. ROBERTS: Yes. So contingency reserves are reserves either offline or online that you can utilize. And we say within 10 minutes because you got to have sometime to deploy, but the standard is to comply with recovery from the loss of a large unit within 15 minutes. So what you would do is -- for example, if we lost Harris, 1000 megawatts, we would have to deploy that offline faststart, CTs, voltage reduction, and then online and call for emergency assistance needed to recover that 1000 megawatts within 15 minutes.

So that's how contingency reserves would be utilized. Versus regulating reserves, that's basically to handle that variability of the load and that can cause an imbalance between your resources and your demand in a short period of time.

MR. METZ: Thank you, gentlemen. That's all the questions I have.

MS. EDMONDSON: That's all the Public Staff has.

CHAIR MITCHELL: Okay.

MS. EDMONDSON: Thank you.

CHAIR MITCHELL: Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: I'm coming back once more. So I'm thinking that I'm recalling a contract. I hate to beat the dead horse but I do think I'm recalling contract with Duke and a gas company where it was stated that the gas company would provide daily and hourly interruptible redelivery service? Does that ring a bell with you?

MR. McALLISTER: Um, no. No, it doesn't.

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COMMISSIONER BROWN-BLAND: All right. Thank you.

CHAIR MITCHELL: Let me make sure there's no additional questions for Duke.

(No response)

CHAIR MITCHELL: At this point, gentlemen, you may step down. Thank you very much for your participation today. It is just about 1:30. We will break for lunch. Let's go off the record, please.

(A recess was taken from from 1:30 p.m. - 2:30 p.m.)

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C E R T I F I C A T E

I, TONJA VINES, DO HEREBY CERTIFY that the Proceedings in the above-captioned matter were taken before me, that I did report in stenographic shorthand the Proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability.

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Tonja Vines

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