PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Wednesday, September 21, 2022

TIME: 9:34 a.m. - 12:47 p.m.

DOCKET NO.: E-100, Sub 179

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Daniel G. Clodfelter

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

Commissioner Karen M. Kemerait

IN THE MATTER OF:

Duke Energy Progress, LLC, and

Duke Energy Carolinas, LLC,

2022 Biennial Integrated Resource Plans

and Carbon Plan

VOLUME: 19

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TABLE OF CONTENTS

EXAMINATIONS

E X H I B I T S

	IDENTIFIED/ADMITTED
Reliability Panel Exhibit 1.........	201/-
CIGFUR II and III Reliability ...... Panel Direct Cross Examination Exhibit Number 1	215/-

P R O C E E D I N G S

CHAIR MITCHELL: All right. Good morning. We will go on the record. Before we begin, let me check in with counsel to see if there is anything for the Commission's attention.

MR. JIRAK: No, Chair Mitchell, not at this time.

CHAIR MITCHELL: Mr. Josey -- Mr. Smith, go ahead.

MR. SMITH: No, Chair Mitchell. We were unable to come resolution on the issues that we discussed yesterday, but we will let you know if anything comes -- don't plan on filing anything.

CHAIR MITCHELL: Okay. Thank you for that update, Mr. Smith. To the extent that we go into any -- or counsel feels the need to ask questions that go into confidential information associated with the Duke Avangrid confidentiality arrangement, we will hold the -- I ask that you-all hold those questions until rebuttal, give you-all a chance to try to work through it. If you're unable to work through it, somebody needs to apprise the Commission of that so that we can just be careful to avoid any questions on confidential information going forward. Any questions, Mr. Smith?

MR. SMITH: No, that works for me. Thank you.

CHAIR MITCHELL: Okay.

MR. JIRAK: Understood. And to be clear, we believe further conversations are needed, and at this point we have obviously a different perspective. We hope that we can find an amicable solution that resolves it, and we'll continue to work on that offline.

CHAIR MITCHELL: Well, you've got some time before rebuttal, so. All right. Before we begin, the Commission is gonna take judicial notice of the full and complete Attachment N-1 to the joint open access transmission tariff of Duke Energy Carolinas, LLC; Duke Energy Florida, LLC; and Duke Energy Progress, LLC on file with the Federal Energy Regulatory Commission as of today, which is September 21, 2022.

The Commission will also take judicial notice for purposes of the record in this proceeding of the filing or the document that's available on the website of the North Carolina Transmission Planning Collaborative dated

August 15, 2022, which is identified as the status of NCTPC's review of red zone expansions plan projects and release a final 2021 midyear update to the NCTPC transmission plan.

All right. With that, Ms. Farver or Mr. Roberts, good morning. Just a quick reminder, y'all are under oath, and we are here today to finish up questions from the Commissioners and then take questions from counsel on those Commissioner questions.

Whereupon,

SAMMY ROBERTS AND MAURA FARVER,

having previously been duly sworn, were examined and testified as follows:

CHAIR MITCHELL: Let me check in with colleagues to see, Commissioners, any questions since we left the hearing room yesterday?

(No response.)

CHAIR MITCHELL: Okay. I have some questions I would like to ask you-all, and I will do my best to just get through them efficiently. All right. Let's see.

EXAMINATION BY CHAIR MITCHELL:

Q. Mr. Roberts, you have testified extensively at this point on the procedures of the NCTPC. And I know that you are intimately involved with the NCTPC and that you were -- you were more than familiar with the procedures that that body employs.

Walk me through, though, at a high level, just the process that the body goes through each year, I believe, in ultimately approving or voting on the transmission plan for that year. So can you start at the very beginning and just walk through the annual process?

A. (Sammy Roberts) Yeah. So there's usually a scope document that gets put in place as to what's gonna be covered in the annual transmission plan, and then early in the year, there's the chance for TAG stakeholders -- TAG stakeholders.

(Audio feedback.)

CHAIR MITCHELL: Let's keep talking. Let's see if it persists.

THE WITNESS: So for -- for TAG stakeholders to provide input on public policy request or economic studies so those studies can be obtained -- or a request can be obtained early in the year around the February time frame. If those requests are provided, an additional scope has to be developed around those studies. Then, as we go on through the year, we have quarterly transmission advisory group meetings to update the stakeholders on what's going on with the -- with respect to the studies, study scope, et cetera.

As documents are drafted, they're posted on the NCTPC site for review. And the NCTPC will receive feedback on that. Throughout that time frame, you're having OSC meetings and PWG meetings to conduct business, make sure that we're progressing with respect to our schedule, which is usually established at the end of the prior year. Make sure we're progressing according to that schedule.

And then midyear, there's the midyear update to the prior year's plan that was approved by the OSC, and that's where we were seeking to include the RZEP projects. And one of the things I'll state is the reason we weren't requesting additional studies associated with the RZEP protects is that our conclusion was that the studies have already been done -- had already been done with respect to the generator interconnection request. The system impact studies.

And so that was the basis for providing the mapping and reviewing that with the TAG group on June 27th with respect to the midyear update. And as you know, with the Commission order associated with, not including the RZEP projects and the baseline, in addition to some of the TAG stakeholder responses that we received, we agreed to remove those RZEP projects from the midyear update. And so just continuing on with the rest of the year, we conducted the supplemental studies associated with the RZEP projects by further basis or the need for those projects. Through this proceeding we're requesting acknowledgement from this Commission that these RZEP projects are needed and used and useful, have more benefits than just connecting renewables associated with executing the Carbon Plan.

We'll have another stakeholder meeting in October to review those supplemental studies. The reliability -- annual reliability study will continue to be done, and that should be finished up in that October time frame as well. I don't know that we'll be able to provide that overview in the October TAG meeting, but we'll provide an overview toward the end of the year with respect to TAG or post it on our NCTPC site, the report associated with that annual reliability study.

And then the OSC will vote on that, pending feedback from TAG stakeholders. And usually that gets posted as a final report in the January time frame the following year.

Q. Okay. Thank you for that, Mr. Roberts. For now, let's -- I do have some questions for you on the RZEP, but for now let's just focus on process, that I make sure I understand completely what the process the NCTPC employs. So you -- during the year.

So your testimony began that there's typically a scope document. And so my assumption -- and you disabuse me of this assumption if it's incorrect.

My assumption is that you-all begin with the most recently approved local transmission plan, and you identify actions or work that needs to be done during the year on that plan; is that correct?

A. Right. Usually, in the annual local transmission plan, the changes are primarily associated with transmission upgrades associated with interconnections agreements that have already been signed, planned generator retirements, additional resources, additional points of delivery load that's been incorporated into the model. All of that is studied in the base reliability case.

Q. Okay. And so the base reliability case is studied.

That's an annual study that the group performs?

A. That's correct.

Q. Okay. And is that the October study or do y'all study before October?

A. Yeah. So once again, that's progressed throughout the year, and usually the final study results come out in the October time frame.

Q. Understood. So in your -- so as I understand your testimony, the study and the analysis of these different drivers of transmission needs, from interconnection requests to planned generation retirement to anticipated load changes or perhaps generator addition, those things are assessed throughout the year, and then you'll have the results of the final study sometime in October?

A. Yeah. And usually -- usually the report -- the draft report will be posted in the November time

frame --
Q. Okay.
A. -- on the NCTPC site.
Q. Okay. And the -- sort of setting aside for a minute the opportunity of the TAG to comment on the drivers of transmission needs or the study process during the course of the year, is it the LSEs who bring the -- who bring the inputs to the -- or bring the data to the group to be studied in each year?
A. Yeah. For the local transmission plan, the annual reliability study, that's correct.
Q. Okay. And then who actually performs the study?
A. So the planning working group actually performs the study.
Q. And I recall -- and again, please tell me if I heard you wrong. I recall earlier in this hearing you testified that the study that the planning collaborative does, or the PWG does, is different from the study that's conducted for generator interconnects, and that they really should -- there should be some work done to try to make those studies more similar. That's how I heard your testimony, but is that -- did I hear you right or is that --

A. So for the reliability study, since they're to the point -- the interconnection -- resource interconnections are on the point of having an interconnection agreement, those additions are studied as if the generator exists in the base model. And if it's a public policy request or economic study, those are looked at in a different manner. But to answer your question more succinctly, yes, the studies need to look at these public policy requests as more like a generator interconnection study.

Q. Okay. And talk for a minute about what that -- what that means, specifically.

A. Right. So, specifically, that means looking at max gen scenarios in local areas; i.e., making sure that the existing gen -- generation in a certain area where you're looking at adding -- making assumptions of new generation being added, can still maintain its firm deliverability to serve load. I mean, that's one of the main points that need to be looked at with respect to more -- being more like a generator interconnection study, is the firm deliverability piece.

Q. Okay. Okay. So then sometime in October or November, you-all have the final results of the study that's been -- the study or studies that have been

ongoing throughout the year. And then what happens?
A. Right. And that's the reliability study. If it's a public policy request or an economic study, sometimes those results don't get finished -- finalized until the next spring time frame.
But going back to your original question, when we get to that draft report that's posted, we allow time for feedback. And then pending the feedback, resolution or incorporation of that feedback, the OSC usually approves that local transmission plan in December. And it gets -- once again, the final report gets posted usually in January of the following year.
Q. And does the report -- describe what the report looks like.
A. So the report goes through some of the NCTPC process, what we're looking at, kind of what the responsibilities of NCTPC are, at the beginning of the report. And then it basically shows the -- what was considered in the -- in this report compared to last year's report. And then it basically states, toward the end, that there were no reliability issues encountered with respect to the studies.
Q. So does the -- does the report identify

specific transmission projects that need to be constructed or --

A. Yeah. There are specific transmission projects that can be identified through the report, but -- and if -- and if it results from the reliability study piece, then those would go into the base plan associated with the DEP and DEC planning models.

Q. Okay. So the reliability -- projects that meet a reliability need go into the base plan. Okay. And then help me understand specifically what the base plan is.

A. Right. So when I was referring to the base plan, I was referring to DEC and DEP's base transmission planning study models.

Q. And are those -- I assume those models inform capital investment and transmission or construction of transmission needs at some point in the future?

A. That's correct.

Q. Okay.

A. It would be similar to a project going into what's called our transmission additions plan, which is our 10-year transmission plan.

Q. Okay. So help me understand how the base -- the base plan and the transmission addition plan work together.

A. Right. So if the projects end up as showing to be needed in the local transmission plan, the NCTPC local transmission plan, then those projects would be translated to the base models associated with DEC and DEP transmission planning models. And they would be translated to the transmission additions plan.

Q. So is the -- just so I'm -- make sure I'm clear here. So the base plan is a planning document. And is the transmission addition plan more of an execution --

A. Yeah.

Q. -- document? Okay.

A. It's more of a projects-related document.

Q. Okay. Okay. Often in these discussions, and throughout the course of the past couple of days as we have been discussing transmission, we talk about base plan, base case, baseline, and we're not really careful with our terminology. So I want to be really careful with our terminology, at least so that I make sure I understand exactly what the utility is -- the case that the utility is making.

So I've heard you say coming out of the local transmission plan, which is a document that's -- that results from the annual work of the NCTPC and is defined in the Companies OATT is the base plan. And each of DEC and DEP have a base plan that then gets translated into a transmission addition plan.

I assume each of the operating Companies has that transmission addition plan that the Company works off of; is that right?

A. That's correct.

Q. Okay. And then when we talk about baseline, help me understand when parties in here or counsel are using the terminology "baseline," what do they mean?

A. Yeah. So, for example, with the Commission's Order that we not include the RZEP projects in the 2022 DISIS baseline, was the terminology used, that would be what I would refer to as the base plan that set up that model.

Q. Okay.

A. And, of course, like, for 2022 DISIS where you're looking at connecting resources in 2026, you would want to be using a 2026 base plan, what's known for that base plan to study those interconnections.

Q. Okay. So let me make sure I heard that right.

So for the 2022 DISIS, because we're assuming

interconnection in the 2026-ish time frame, you need to look at the 2026 base plan for purposes of the DISIS?
A. That's correct.
Q. The study process that's involved in the DISIS?
A. That's correct. For the solar procurement, yes.
Q. Okay. Okay. So just going back a little bit into the -- your testimony is that economic studies and public policy studies can take longer than the year. So if we're -- if we assume, as I understand, that the reliability study typically completes within the course of the year, the economic study and the public policy study may take longer.
So what happens with results of those studies?
A. Right. They can generate projects that ultimately go into the base plan as well.
Q. Okay. And I -- so if those studies indicate -- so let me just back up. Walk me through how that would happen.
A. Yeah. So if a public policy request is made and -- in the February time frame, and the scope is developed, the study is performed, and it shows the

need for certain projects, local projects, then those projects will make it into -- when that study is concluded, those projects can make it into the local transmission plan for that year.

Q. Okay. And to make it into the local transmission plan, I assume that they have to go through the same process; they get commented on by the TAG and then ultimately have to be voted -- voted on by the OSC; is that correct?

A. That's correct.

Q. Okay. And then assuming the OS- -- let's assume that the OSC votes to approve the projects that are identified out of an economic study or a public policy study, then would those projects, assuming that there is a project for the DEP -- for DEP or for DEC, would those projects then be incorporated into the base plan?

A. If they're approved in the local transmission plan, yes.

Q. Okay. So the base -- so the base plan could include reliability projects or public policy projects or economic projects assuming approved by the OSC?

A. If the study has been conducted and it shows the need for those local projects and it's been voted on, yes.

Q. Okay. I'm sorry to make you go through this.

A. No worries.

Q. But this is very helpful to my understanding.

A. And I will just add that, with respect to the RZEP projects, the conclusion that the Companies had were -- was that the -- there were sufficient studies that were already done. And so the -- what was needed is presentation of those studies and subsequent TAG holder review, stakeholder review, and OSC voting to put that into -- the midyear update was the original thought, and then now the local transmission plan end of the year would be what we're looking for.

Q. Okay. So just following up on your testimony there, so I understand the Company -- your testimony to be that the Company felt -- well, the Companies, I assume, DEC and DEP, felt that sufficient studies had already been done on those specific transmission needs or projects?

A. That's correct. And now we have an additional study that shows more evidence that --

Q. Okay. We'll get to that one in just one second. Let me walk through this. So you've presented those studies to the TAG and have been receiving commentary, comments from the TAG over the course of the year.

And then at some point, those projects have got to go before the OSC for a vote?

A. That's correct.

Q. And then let's assume for the sake of this discussion that the OSC votes to approve some or all of those RZEP projects, then would Duke -- DEC and DEP then incorporate whatever gets approved into the base plan?

A. That's correct.

Q. Okay. And then so the baseline for purposes of the DISIS windows or the DISIS -- the studies associated with the various DISIS windows would be the base plan that's approved -- that has been approved that would include these RZEP projects?

A. Right.

Q. Again, assuming my hypothetical approval by the OSC?

A. So we would see the RZEP projects going into the base plan study model for the 2023 DISIS.

Q. Okay.

A. If the RZEP projects were approved by the NCTPC and the local transmission plan this year.

Q. So -- and remind me, Ms. Farver, you might know this. When does the 2023 DISIS window open?

A. (Maura Farver) It opens January 1st of 2023, but it closes June 29th. It's a six-month window.

A. (Sammy Roberts) Right. And the phase 1 study wouldn't start until end of August.

Q. Okay. Okay. So I want to talk some, Mr. Roberts, since you brought it up, the additional study.

And when you just referenced an additional study a few minutes ago, are you referring to the study of the 5,400 megawatts?

A. That's correct. We refer to that as the supplemental studies in the testimony.

Q. Okay. Can you walk me through the supplemental studies, just sort of beginning to end?

A. Yeah. So the Commission stated in their Order on the 2022 solar procurement that more clear evidence was needed to show that the RZEP projects were needed. And so in subsequent discussions with the Public Staff on conducting a supplemental study, we reviewed a scope associated with that study, and said we'll look at 5.4 gigawatts since, in the aggressive portfolio one case, that's what's needed to get to

70 percent by 2030.

We agreed on a 60/40 split -- 40 percent in DEC, 60 percent in DEP -- which translated to 1,900 megawatts of solar in DEC, and 3,500 megawatts in DEP. And then in order to ensure a nondiscriminatory selection manner of that solar, we started at the transition cluster study and went back in time just far enough to select enough solar to meet those parameters, 1,900 in DEC and 3,500 in DEP.

Q. Okay. And so -- and so help me understand what the study demonstrated.

A. Yeah. So we performed a study of that amount of solar connecting in DEC and DEP based on that nondiscriminatory selection of solar, and we performed, really, a cluster-type study. So similar to the transitional cluster study. We looked at -- just like a generator interconnection study, a cluster generation interconnection study would be performed with that 5.4 gigawatts. And the results showed that 15 of the 18 original RZEP projects were still needed and will facilitate a substantial amount of solar being able to be interconnected without those hurdles causing significant solar to withdraw from the queue.

Q. Okay. I'm gonna ask a little bit out of sequence here, but just so I don't forget to ask it. You said the study -- the study demonstrated that 15 out of the 18 original RZEP projects. So the projects that make up the RZEP have sort of evolved over time to a limited extent, that's my understanding at least.

Where can I find in what y'all have put in the record the current -- the current list of RZEP projects?

A. Yeah. So there's more in the rebuttal testimony.

Q. Okay.

A. But the final list, based on Public Staff testimony, where we are requesting acknowledgement from the Commission, is found in the rebuttal testimony in a table -- yeah. So the original list is provided in the mapping of Exhibit 1 and Exhibit 2, but the final list that we're requesting, based on Public Staff testimony, direct testimony, is found in -- I believe it's Exhibit 3, subject to check, in the rebuttal testimony.

Q. In the rebuttal testimony of this panel?

MS. KELLS: Chair Mitchell, it is Exhibit 3 to the rebuttal testimony of this panel has the up-to-date list, yes.

Q. Okay. And your testimony is that's with what the Public Staff -- that's based on either discussion or testimony in this proceeding with Public Staff, the final list?

A. The final list is a result of the Public Staff's direct testimony.

Q. Okay.

A. And we'll discuss that more in rebuttal.

Q. Okay. And remind me, what is the estimated cost of the final -- of that final group of projects?

A. Right. Subject to check, I believe it's around $540 million.

Q. Okay. Again, just kind of staying with the current iteration of the RZEP universe, Mr. Roberts, based on what you know, and this is a bit outside of your purview and expertise, and I recognize that, but I'm gonna ask you anyway, are there developments, whether they be technological or design or operation, that you foresee or that the Companies foresee that would result in those costs -- those cost estimates, let me be clear -- being adjusted upward or downward?

A. I mean, they're -- they're a risk with any transmission upgrade project: materials, cost, inflation, workforce availability, et cetera.

Q. And I understand all of those types of risks, and the parties have covered those well.

But what I'm really interested in is, are there -- are there things foreseeable? Are there -- are there influences foreseeable to the Companies that would influence the extent of these costs, whether up or down? Other than the risks that we, sort of, commonly identify.

A. Right. So, you know, thinking about emerging technologies, that sort of thing.

Q. Or design standards?

A. Right.

Q. Or experience gained from operations that may lead the Company to, you know, develop the transmission system in this way as opposed to that way? I just -- I want to have an understanding of whether there's anything on the horizon that is reasonably foreseeable that will influence the extent of these costs?

A. Not that I'm aware of. I mean, these are really old assets that -- a lot of these are really old assets that need replacing from that perspective. And, you know, the benefit -- one of the benefits is being able to connect more larger solar facilities. And there's lower line losses with respect to increased conductor sizes, et cetera. Some of these benefits.

Other benefits are described in the testimony.

Q. Okay. Let's see. Going back now, I'm taking you back to your testimony about the -- that was a little bit of a digression, so thank you for answering that question. But the -- your -- the supplemental studies that you-all performed on the 5,400 megawatts, and do I understand your testimony correctly to be that the type of studies that you all performed on -- on these -- and were you -- let me back up.

Were you studying the -- were you studying interconnection requests for 1,900 megawatts in DEC and 3,500 megawatts in DEP, or were you study -- or were you studying -- what exactly were you studying?

A. Yeah. So going back just enough in time in the past to get to those levels of megawatts for DEP and DEC, we were studying historical generator interconnection requests.

A. (Maura Farver) And just to elaborate, because I think the reason for that is you can't just say we're gonna add 5,400 megawatts of solar and just have a general assumption like that in this kind of specific had modeling exercise. And so going back in time, having that very specific data from past generator interconnection requests is what's needed in order to do that more specific modeling exercise.

Q. Okay. I'm sorry, go ahead, Mr. Roberts.

A. (Sammy Roberts) I'll add one more point, in that another thought, you know, reasoning for that was we felt that recent generator interconnection request, you had to have a land lease option or land lease associated with that -- putting that request into the Company with respect to being able to be studied in the interconnection queue. And so that means that the viability of that solar entering the queue again would be higher.

Q. Okay. Okay. So the determination that 15 of the 18 original RZEP projects were needed, finish that sentence for me. Were needed to?

A. I'm sorry. Could you restate?

Q. Yes. So your testimony was the studies -- I'm paraphrasing a bit here. But your testimony was -- and you correct me if I've gotten it wrong -- 15 of the 18 original RZEP projects were needed.

A. Yeah.

Q. Were needed to what?

A. To enable certain amounts of solar being connected. And I think the number was in aggregate around 3,600. Because not all the projects in the

5.4 gigawatts selected were in the red zone. Some were outside the red zone.

Q. Say that last piece again. 5 percent of the projects were outside of the red zone?

A. Some of the projects were outside the red zone.

Q. Some of those interconnection requests that you studied --

A. Right.

Q. I gotcha. Okay. Okay. But, Mr. Roberts and Ms. Farver, isn't -- isn't it the case that, whether a solar generator interconnects is almost completely or entirely dependent on project economics supporting the interconnection of that facility? I mean, let me ask it a different way. If you are -- were you-all assuming that the solar generators that would be interconnected as a result of the development of these RZEP projects would not have to pay for the RZEP projects?

A. So if the project is in the base case, the base plan, then the assumption would be that that transmission upgrade is a foregone project, and so the transmission interconnection customer would not pay for that upgrade.

Q. Okay. So I think you've clarified something for me, which I did not understand previously.

So the studies that you-all performed assumed the RZEP projects were in -- the baseline for these -- for this supplemental study included the RZEP projects?

A. So the supplemental studies did look at the RZEP projects not being in the base plan, or not being in the base case per the study. And then you basically include in a cluster study-type fashion this 5.4 gigawatts of solar facilities. And the results were these were the constraints that result associated with the change case. The change case being you add this 5.4 gigawatts of solar.

Q. Okay. So -- okay. So I'm on the -- I'm clear now.

So the -- the study's determination that 15 of the original -- of the 18 -- 15 of the 18 original RZEP projects are necessary did, in fact, assume that the generator isn't paying -- isn't paying for the transmission projects, those 15 transmission projects?

A. Right.

Q. Okay.

A. So I'll let Ms. Farver speak.

A. (Maura Farver) Well, I don't think that these studies assumed anything about who pays for them. It was trying to identify what those necessary upgrades would be to accommodate these projects. And then the cost allocation would be based on, you know, are these approved through the local transmission plan or another pathway.

Q. Okay. Understood. So the studies essentially put aside the -- assumed someone was paying for them? Okay.

A. Right. The study looks at, from all these interconnecting customers, what are the problems identified. Then solves for what is the upgrade or solution needed to fix that problem or issue, and then estimates the cost to build all of those.

Q. Okay.

A. It doesn't make an assumption about where that cost goes.

Q. But my concern is, though -- and this is a question I want you all to agree with or disagree with -- if a generator -- whether a generator ultimately interconnects and goes into service depends on how much it costs to construct the generating facility plus any amounts of transmission work that has to be done for the project, right? And so -- so I see you nodding, Ms. Farver, are you --

A. I don't want to anticipate where you're going with this.

Q. Well, but -- I mean, isn't that a fair assumption to make?

And so if you are removing -- so any conclusion about how much solar these projects facilitate really has to be predicated on how much cost the solar generating facilities can bear; is that correct?

A. I'd put it slightly differently.

Q. Okay.

A. So now that we have 951, we recognize that there is a need for a lot of solar in our future, and we just haven't seen as many applications and opportunities, or I should say requests and opportunities in non-red zone areas. So I don't know that that means that there's a cost calculation. It might just be unavailable land. There might just not be as many opportunities in non-red zone areas.

And so the question of, well, is it gonna be more expensive with these red zone upgrades compared to building outside of the red zone; there just might not be the land available. There might not be big land leases, there might not be an opportunity to collaborate with multiple landowners to get these multiple land leases. The geography might not cooperate.

So I think there is just a limit in the sheer number of projects outside of the red zone, given that we keep seeing projects bidding and putting interconnection requests in the red zone, despite the fact that I think it's well known that these constraints exist. Did that answer your question?

Q. It does. You sort of -- you -- yes, you've provided a helpful response. The -- I guess the -- my concern is -- that I'm hoping that y'all can address is your testimony is there is a need for solar. I don't want to -- there -- that's what I heard. The Companies have determined and identified a need for solar in order to achieve compliance with the statutory mandates we've now got on the books.

So what assumptions, though, is the Company making -- just again for purposes of helping me understand, what are -- are we assuming that the solar is cost-effective without looking at the transmission needs that are going to be associated with the solar?

A. So subject to check with the Modeling Panel, I think that's accounted for in the transmission cost adder in the modeling work, and so Mr. Roberts may --

A. (Sammy Roberts) That's correct.

Q. Okay.

A. So in the -- I believe it's Table E-44, base transmission cost proxies -- upgrade proxies for solar, there's some basically stratification upon periods of years. And with those numbers, the -- we actually included the cost of the red zone projects in that baseline number.

A. (Maura Farver) So the red zone costs are accounted for in the transmission adder in the modeling work.

A. (Sammy Roberts) That's correct.

Q. Okay. And, Mr. Roberts, you mentioned -- you mentioned Table E-44?

A. That's correct.

Q. In the Modeling Panel's direct testimony?

A. That's Table E-44 in the Carbon Plan.

Q. The Carbon Plan. I'm sorry. Yeah. Okay.

A. Appendix E of the Carbon Plan.

Q. I was wondering if -- I know Mr. Snider has put a lot in the record, I was thinking 44 tables, that would be -- I wouldn't put it past him, but that would be impressive. Okay. All right. So make sure I'm understanding this correctly.

So the modeling that the Companies have conducted in support of the portfolios that have been constructed for purposes of this exercise or for this proceeding takes into account transmission work that's gonna have to accompany solar generation going forward?

A. (Maura Farver) That's correct.

Q. And costs associated with the red zone are included in that transmission cost adder?

A. That's correct. And the model is still selecting solar with those costs considered.

Q. Okay. Okay. The -- I think I recall the testimony, and y'all correct me if I'm wrong, that in the first DISIS cluster, 1,500 megawatts of the -- of the generation or the interconnection requests that participated in the cluster falls outside of the red zones; is that correct?

A. That number is a better reference point for the solar that's participating in the RFP, which is primarily in DISIS.

Q. Okay. Okay. In the 2022 procurement; is that what you're --

A. That's correct.

Q. Okay. And at this point in time -- and I'm not -- I don't want to -- I'm not trying to get into any sort of confidential information with the question, but is it too early in the 2022 procurement process for the Company to have an understanding of how competitive the solar is that falls outside of the red zones relative to the universe of interconnection requests or projects that have applied to participate in the RFP?

A. It is still too early for any conclusion on that, yes.

Q. Okay. The -- Ms. Farver, the red zone project, we've talked about sort of this projects in, projects out, and I'm aware of what happened with the transitional cluster, where we essentially had a number of projects fall away. I think we've got 100 megawatts left in that transitional cluster.

Are they the same projects coming back into -- is it the same projects or same group of projects that keep coming back into these procurement opportunities, be they, I guess, the DISIS -- well, let me ask the question differently.

When we talk about projects withdrawing from the queue and reentering the queue, are we talking about withdrawing from the transitional cluster process and then reentering the first DISIS window?

A. Some of this is subject to confidentiality. But without going down that path, there are projects that dropped from the transitional cluster process and reentered the DISIS process. I don't know the exact percentage.

Q. Okay. That's fair. And that's a perfectly fine response.

A. (Sammy Roberts) And I'll add, from Appendix B, we had -- we showed 35 out of the 43 projects requesting interconnection in DEP transitional cluster study, representing 1,445.9 megawatts showed dependency on what's known as the Friesian projects, which we're well aware of.

Q. And what does that mean exactly, Mr. Roberts?

A. So there's -- there's still solar that's locating in that same location that's showing the same dependencies occurring again and again as we saw in serial studies.

Q. Okay. Let me stop you.

So does that mean those projects that are showing up again and again are assuming the Friesian -- those Friesian upgrades will be constructed?

A. So in the transitional cluster study, what this meant was that the Friesian projects were an insurmountable hurdle with respect to moving forward with interconnection.

Q. And why were they insurmountable hurdles?

A. Probably because of cost allocation.

A. (Maura Farver) Just to add onto that, I think, you know, transitional cluster was the first opportunity to have those costs allocated across multiple projects. And so I think that was sort of our first indication of can a group of projects collectively fund these projects to move forward -- or these upgrades to move forward. And we saw a lot of projects drop out.

And so now we're in DISIS, we have, you know, even more megawatts, and so we are testing again, will these costs be spread across enough generators that they can bear it collectively. And, you know, the reason we're proposing the RZEP is primarily from a timing standpoint, we can move this forward quickly, or more quickly, we don't have to wait until the very end of the DISIS to know if they can be built or not. And there is risk of these projects that are sharing the costs, dropping, you know, they're not all part of the RPP, there are projects that are not in the RFP. We don't have control over which projects choose to move forward and choose not to.

A. (Sammy Roberts) And it's the difference between the RZEP projects benefitting just one cluster versus looking at that over time several clusters.

Q. Okay. Let me stop you right there, Mr. Roberts. So make sure I -- make sure I understand this correctly. So let's take the first DISIS window.

I think you have 10 -- is it 10 gigawatts, about, in the first DISIS window; does that sound right?

A. That's correct. But that's different resource types.

Q. Understood. Understood. But the network upgrades associated with all of the projects, right, would be -- so let me ask the question clearly.

How -- how are the -- how would the transmission network upgrade costs be spread across participants in the DISIS window?

A. (Maura Farver) I can describe this at a high level.

Q. Please do.

A. The projects that contribute to that upgrade, you know, when they do a power flow study, they determine the defects, which is essentially the contribution, the proportion that you're contributing to that upgrade, that's used in determining the allocation of how the cost of that upgrade is spread across projects.

Q. Okay. So a project would be -- would be allocated costs associated with transmission if it contributed to the need --

A. That's right.

Q. -- for that upgrade based on engineering studies that the Companies are performing?

A. That's correct.

Q. So it only pays for the upgrade or a portion of the upgrade if it contributes to the need for those upgrades?

A. That's correct.

Q. Okay. Can you -- okay. That's helpful. Thank you for that explanation.

The 180 megawatts that survived or that remained standing after the transitional cluster, what -- what can you tell us, if anything -- I don't know how much of -- how much of this gets into confidential information, so you're just gonna have to help me understand that.

But what can you tell me about transmission upgrade costs for those -- for that 180 megawatts? Are there transmission upgrade costs?

A.   I don't know the details of the network upgrades associated with those 180 megawatts, but I, subject to check, believe that all of the -- Mr. Roberts might know this. The red zone upgrades that were identified in phase 1, the projects remaining do not contribute, or very few of them contribute to what we've listed as the red zone.

Q.   Okay. That's a good enough response. Thank you for that. You answered the question I tried to ask.

A.   Great.

Q.   Thank you. Okay. Y'all just bear with me, I'm sorry I'm taking so long here. Okay. Okay. The -- you've -- I think you-all have already testified to this, but I didn't -- I don't remember what you said or I didn't hear it clearly or I didn't understand it or some mix of the three of those.

When you -- these transmission upgrades that y'all are identifying as the RZEP, this bucket of projects, in the work that y'all have done to study this -- these projects or the need for these projects, are you assuming separate operations, DEC and DEP, or are you modeling consolidated operations?

A. (Sammy Roberts) Right. So these are studied based on the current transmission planning zones, planning area, so DEC and DEP separately.

Q. Okay.

A. There could be, subject to check, if the Camden Wateree line, for example, is still in the RZEP list of projects, the final 14, then that could help with respect to transfer capability between the two areas as they exist today. Once again, that's subject to check, but that's the only one.

Q. When you say that's the only one, that's the only one that what?

A. Only one that would be mutually beneficial to both areas.

Q. Okay. So do I understand, then, that to mean that if y'all -- if you were to model as -- if you were to model consolidated operations, as I understood -- as I understand to be the case for the modeling underlying the scenarios developed for the Carbon Plan, if you were to model in the same way, granted I know it would be a different model, but would you -- you don't -- with the exception of the Camden Wateree line, you don't think there would be any impact on the projects that would be necessary to resolve the red zone constraints?

A. No, I do not.

Q. Okay. Just -- okay. The -- is it the Companies' position, or is it y'all's -- is it your testimony to this Commission that, with respect to solar generation that needs to be interconnected to satisfy certainly the interim compliance obligation as well as the long-term compliance obligation, the DISIS process and the construction of 15 of the 18 red zones is the most cost-effective way to facilitate the interconnection of that solar?

A. (Maura Farver) Yes.

Q. If the -- is it -- let me ask that question in a different way. Is the DISIS process, in combination with the construction of -- let me ask it this way.

Is the DISIS process, in combination with the inclusion of the 15 -- 15 RZEP projects that Mr. Roberts has testified to in the baseline for DISIS 2023, assuming solar is interconnected following the results of that second DISIS window, will that be the most cost-effective solar that can -- that can be interconnected -- let me ask the question a different way because this is not -- I'm not asking my question clearly.

Ultimately, it's the Commission's obligation to ensure that the Companies embark on the least-cost path to compliance with the statutory emissions reduction goals.

Is the Companies' proposal for inclusion of certain of the red zone projects in the baseline going to allow the Company to meet that goal or meet that obligation, that least-cost obligation with respect to the solar that's interconnected?

A. Yes. And I think the modeling work supports that, because since these RZEP costs are assumed in the transmission adder in the modeling and assumed in that price of solar, and solar is being selected as a solution in the model, that indicates that even with the red zone costs associated with the solar, they are still part of the least-cost solution.

Q. Okay. The -- okay. I'm gonna just -- I'll surrender at this point.

CHAIR MITCHELL: Any additional questions? Okay. Let me -- let me let Commissioner Clodfelter go, and then you go.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. I want to follow up one point that you discussed with Chair Mitchell. It concerns the supplemental study. If you want to have it there in front of you, it's Exhibit 3, I think your counsel identified. In -- as I read the supplemental study, and I'm gonna use DEC, because I think the answers will be the same for DEP to the questions I'm gonna ask.

For purposes of the study, you were trying to see what would be required to interconnect 1,937 megawatts of additional solar in DEC using the project selection criteria that you've already described for --

A. (Sammy Roberts) That's correct.

Q. -- to compose that. So the study identifies four red zone projects -- as you told me yesterday they're all in South Carolina -- that would be required. But it also identifies 24 other transmission upgrades that would be required in order to reliably interconnect that 1,937 megawatts.

Am I reading the study correctly?

A. That's correct.

Q. So when you did the transmission adder calculation for purposes of modeling the selection of solar resources, what happened to the costs associated with those 24 additional transmission upgrade projects? Were those included in the calculation of the adder?

A. Yeah. So some of those projects are connected to 44, so you can be -- you can manage those.

Q. Those would be probably assigned to the interconnecting generator?

A. Right.

Q. Because you only allowed one per 44 kV?

A. That's right. Or they would probably submit an -- or request to lower their amount that they wanted to connect. The other ones -- part of that 1,937 was outside the red zone. And just because it's outside the red zone, it may still incur upgrades. So some of these upgrades would be associated with that. Some of these could be associated with projects that are inside the red zone.

And what we've identified with these four projects, the Clinton, the Lee Piedmont, and the Newberry, are common constraints that show up time and time again with projects requesting to be interconnected inside of the DEC area in South Carolina. And these projects typically -- even though they keep requesting interconnection in that area because of land favorability, these projects usually don't allow moving forward.

If you just look at it on one isolated cluster study basis, like the transitional cluster study, that's probably gonna be your result. If you look at it over several clusters, several procurements, then these projects are gonna enable a lot of solar moving forward.

And so yes, these other projects, some of these may have to be funded through crediting policy by the projects. But we see that as being feasible with respect to moving forward with the amount of solar to the Carbon Plan showing how to connect. Not just through 2030, but beyond. And there will probably be more iterations associated with this with more projects, new red zones that come up as we add the amount of solar that we're looking at adding to meet this -- these carbon reduction objectives.

Q. I appreciate the answer, and I understand it, but let me go back and just sort of be sure I get my question clear. So for purposes of these 24 other projects -- and let me just ignore the ones that are on the 44 kV lines, because you're only allowed one project per line on those. So there are not gonna be any interdependencies embedded in the study with respect to those lines or those projects, so let me just ignore those.

With respect to the other Table B projects that you identified as being needed to get that 1,937 megawatts hypothetically interconnected, did the cost of those other projects get included in your computation of the transmission cost adder for purposes of modeling the selection of solar resources?

A. Right. So this project was done after we provided the cost. Or this study was done after we provided the cost into the model. So these costs were not included in that transmission cost adder.

Q. Thank you. Only the four red zone projects, the cost of those was rolled into the adder?

A. Right. Which we see as the majority of the cost, most of the cost associated with enabling connection of a significant volume of solar going forward in that area.

Q. And the same would be true -- excuse me for not letting you finish, but the same would be true with respect to DEP? What you just told me --

A. Yes.

Q. -- is exactly the same for DEP --

A. Yes.

Q. -- except you've got three red zone projects that you said you might be able to delay.

But the Table C projects that would be required to connect the 3,500-plus megawatts in DEP, those costs were developed in the supplemental study after you had already set the transmission adder for modeling purposes?

A. That's correct.

Q. Okay. Thank you. That's the follow-up question I wanted to ask.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. So I'd like to provide a hypothetical, and it really gets to the siting question that the Commission's been concerned about in the past. And let's assume for purposes of this hypothetical that there have not -- there have not been historical generator interconnection requests in this red zone area.

If DEC or DEP were choosing the sites for the additions of large amounts of solar, let's say 3,600 megawatts or 5,400 megawatts, on the DEC and DEP systems, would the red zone, the RZEP zone area, would the Companies have chosen that site or that area to build this amount of solar?

A. Yeah. So looking at the -- and I'm trying -- I think it's Figure 2 or 3 in the testimony. It's Figure 3. Looking at Figure 3 in the testimony, and looking at the high solar viability areas where you don't have as much concern with forestation, population density, land availability, if you look at connecting in those areas, they're primarily red zone areas.

And knowing the volume of solar that we're looking at connecting in the Carbon Plan to meet this goal, this carbon reduction goal, and frankly, for that matter of fact, what was identified in the 2020 IRP portfolios. Looking at connecting that volume of solar, we don't see any way around not utilizing this area associated with connecting that volume of solar.

Q. So let me make sure I heard your answer correctly, that if DEC and DEP were choosing sites and they were building 100 percent of the solar in this hypothetical, there was no, you know, 55/45 split, this area would be a site chosen by the Companies to site this amount of solar to meet these carbon goals?

A. So this area being the red zone area?

Q. Yes.

A. I mean, you've got to have land and you've got to have appreciable land associated with larger solar sites which are -- have been shown through our third-party capital cost model to be lower cost than smaller sites.

So land availability. You know, even with the transmission upgrades that are needed, yes, we need to locate solar to meet the volume. There may be some sites outside -- there will be some sites outside the red zone, current red zone, where you can connect solar with, you know, not that much in the way of transmission network upgrades. But you're not gonna be able to connect the volume of solar that we're looking at moving forward in those areas.

A. (Maura Farver) Just to add on that, I mean, I think a general principal in an ideal world, you want generation close to load; but for solar, there are very specific siting constraints. So you need enough land, you need enough flat land, you need landowners who are willing to lease that land to you or sell that land to you. And so I think there are some very practical limitations about where solar can be. And given those limitations, this Figure 3 is the best indication we have of what that kind of prime solar sites are. And those are clearly overlapping with the red zone areas.

Q. Okay. Thank you for that clarification.
Generally, are you seeing -- what's the trend of FERC-jurisdictional projects entering the queue versus state-jurisdictional projects entering the queue?
A. (Sammy Roberts) Yeah. I don't have the DISIS -- 2022 DISIS queue in front of me, so maybe Ms. Farver.
A. (Maura Farver) I can speak a little bit to that without having exact numbers in front of me.
Q. Right. Just a trend that you've seen.
A. Well, because our 2022 solar RFP has both the PPA track and utility-ownership track, we designed the rules of the RFP so if you were PPA track or if you were bidding a project both PPA and utility-ownership track, you should enter in the state queue. If the project is larger than 80 megawatts, it's only eligible for the utility-ownership track, and so then it would necessarily be a FERC project.
So given the rules of the RFP and the fact that there is a very strong overlap between the projects that are in the 2022 -- the solar projects that are in the 2022 RFP and in the 2022 DISIS, we designed our RFP rules to include instruction that a

lot of these projects would be state jurisdictional. Did that answer your question?

Q. So you're seeing more state-jurisdictional projects than federal-jurisdictional projects?

A. I don't know the exact number, so I don't want to quote it. And also, by megawatts, it's different, because the FERC-jurisdictional projects would be larger megawatts. But I think I can confidently say there are more state-jurisdictional solar projects than FERC.

Q. Okay. And so this might help me with one of the answers with respect to the red zone areas. Mr. Roberts, you testified about insurmountable hurdles based on cost allocation. So with FERC-jurisdictional projects, there's a crediting policy, so really it's a timing issue.

A. (Sammy Roberts) That's correct.

Q. So to get some clarification around that, even with the crediting policy cost allocation, the FERC-jurisdictional projects, are you saying that -- that it's still an insurmountable hurdle, or is it only with respect to state-jurisdictional projects where there is not this crediting policy?

A. Right. I mean, some -- the state projects pulled out as well with respect to the transitional cluster study. I'm saying overall for solar that projects have pulled out, like we experienced with the transitional cluster study, due to the cost allocation in that study associated with these upgrades. But once again, we continue to see projects time and time again request interconnection in these red zone areas.

A. (Maura Farver) And to add onto that, I think you could also say that it is an insurmountable hurdle for some of the FERC projects that have tried to move forward, like the Friesian project. So, ultimately, it didn't move forward. And I -- my understanding it was partly because of the cost of these projects, the upgrades that it was triggering, that the CPCN wasn't granted. And so I think FERC projects may also struggle to move forward, not just state-jurisdictional projects. If they were trying to bear the cost of those network upgrades themselves.

Q. Sure. And then getting back to the siting, I think you answered that with my hypothetical. But just in a more direct fashion, if you put these constrained areas into the base case -- and let me back up for a moment.

In RTO areas, there's participant funding, and one of the reasons that the RTO areas have participant funding is because of the siting issue. They want to make sure that there's incentives to provide for the most efficient siting of projects.

And so is there a concern or should there be a concern about efficient siting if these constraints are being put into the base case?

A. (Sammy Roberts) I don't have a concern. Once again, the RZEP projects will facilitate larger projects which have economies of scale. The likelihood of them moving forward to interconnection agreement will be much greater. And if you look at the dilution of the cost associated with the RZEP projects over multiple clusters versus one cluster, I think that is the inherent true benefit of moving forward with the RZEP projects at this point in time.

Q. Thank you, Mr. Roberts. That's very helpful. So -- so moving to Chair Mitchell's initial questions about explaining the process with respect to the NCTPC, have -- have there been economic projects placed in the base plan in the past?

A. Like I said, I have a limited history with NCTPC. I'm not familiar with any recent economic projects that have gone into the base plan.

Q. And have there been, in the past, any public policy projects placed into the base plan?

A. Yeah. My understanding is, through the 2015 midyear update, there were projects -- public policy projects included associated with the western area modernization law.

Q. Okay. That was 2015 midyear plan?

A. That's correct.

Q. And I think this question's been asked, but I'm gonna ask it one more time.

So how -- how are the RZEP projects characterized? Are they public policy, economic, or reliability projects?

A. Right. So currently we are looking at those as public policy projects, but they could just as easily be characterized as generation addition projects. If this Carbon Plan is approved, or whatever Carbon Plan is approved, it's gonna have a lot somewhere in it.

Q. Okay. Thank you for that. I don't have anything further.

CHAIR MITCHELL: All right. I actually have one more just following up on that last point.

EXAMINATION BY CHAIR MITCHELL:

Q. So in the document from the NCTPC's review of red zone, the red zone expansion projects, it's dated August 15, 2022, there is -- and I'm just gonna -- I know you don't have it in front of you, so you can -- I understand that. The document says or provides that the NCTPC local planning process provides several avenues for consideration of new transmission projects driven by different needs. The first is reliability projects needed to satisfy NERC criteria, maintain reliability. The second is projects needed to integrate new generation resources and/or loads.

And then there is a reference to the OATT, Attachment N-1, Section 41 532 and 536. In reviewing those sections of the OATT, I wasn't sure exactly how those sections of the OATT informed this, sort of, avenue for consideration or category of projects, to use Commissioner Duffley's words. And then -- so I want to ask you about that. But then there's -- there is, sort of, the third avenue would be economic projects and the fourth avenue would be public policy projects.

So this second project, the second category or avenue, projects needed to integrate new generation resources or loads, is it your testimony that these

RZEP projects fall into that category or would pursue that avenue for purposes of the planning process?

A. Yeah. With the Carbon Plan that's approved, 2020 IRP that's approved, you know, it shows the approval of that resource plan requires this amount of solar that needs to be connected moving forward. You could look at these as generation additions. Normally, with respect to the base -- the local -- annual local transmission plan, we include generators that have signed IAs. But as far as that generation additions category for future resources, we could look at an approved Carbon Plan facilitating that.

Q. Okay. So if there -- if the -- if DEC and DEP were to look at an approved Carbon Plan, would that -- do you mean that then you would be pursuing a public policy avenue for these projects?

A. It can be either/or. I mean, it's -- public policy is basically related to changes that are needed due to state law or federal law. And so, you know, House Bill 951 mandates meeting a certain carbon reduction objective, and to do that you've got to have the certain portfolio resources connected over time. So that could be the justification associated with these projects.

If they're needed -- shown to be needed for specific generation additions, and that was the argument that was posed before the NCTPC, it could be used with that avenue as well.

Q. Okay. And so -- legitimately, my last question is, the -- does classifying or categorizing these project- -- the RZEP projects as projects needed to integrate new generation resources or public policy projects have an impact on the way that the Companies would move through the local planning process or the case it would have to make ultimately to the OSC to get approval?

A. With the case with the RZEP projects, once again, usually with, like, a public policy request, the request is made, you perform the study -- you do a scoping document, you perform the study associated with that scoping document, and the local projects identified are the result. In this case, the studies have already been done and the projects have already been identified, so there is really no new study that we deem needs to be done.

Q. Okay.

A. And so those supplemental studies, those past generator interconnection studies are showing these red zone projects are needed to facilitate the generation additions of solar.

A. (Maura Farver) I think there could also be a timing difference. Mr. Roberts, correct me if I'm wrong, but the public policy pathway -- since we are prepared with that evidence, I think the public policy pathway could be something that could be ready by the end of this year. If these costs were borne by generators, they would need a signed interconnection agreement before it came to the NCTPC. And the signed interconnection agreements from the 2022 DISIS won't be in until early 2024, so it would just further delay being able to move the red zone projects forward.

Q. Okay. Okay. All right. I do have one more question. The -- Mr. Roberts, you talked about the dilution of costs. Turning again to the red zone, the RZEP.

Dilution of costs across multiple DISIS windows, I think that's what -- that was your testimony?

A. (Sammy Roberts) That's correct.

Q. How do ratepayers benefit from dilution of costs across multiple DISIS windows?

A. Right. So one of the things that's been looked at by the Public Staff and by this Commission is levelized cost of transmission associated with connecting resources. And so if you -- the -- and the denominator of that is a megawatt hour number. So if you increase that megawatt hour number and hold the top number, the dollars for the transmission, you know, about the same, then that's gonna continue to lower your levelized cost of transmission for that amount of megawatt hours from those resources.

So that's how it would dilute over time. The more those red zone projects were utilized by solar, more and more solar, the more it would dilute that levelized cost of transmission. And I believe there's there LBNL thresholds associated with that.

A. (Maura Farver) And that sort of gets at the question of, once these projects are approved, the study looked at a certain number of megawatts that it would help enable to interconnect, that there can be many more additional projects. We can't put an exact number to just how many more megawatts would be enabled, because it's so dependent on the specific location and the megawatts of each individual project.

So we know that it can enable more megawatts, and that's getting to that point of the dilution, it's spreading the cost across more projects than just what was studied, but we don't have a specific number to ascribe to that because we're not sure where those projects will be specifically located or exactly the size of them, and that's all part of the calculus.

CHAIR MITCHELL: All right. With that, we will take our morning break. So let's go off the record. We will be back on the record at 11:15.

(At this time, a recess was taken from 10:57 a.m. to 11:17 a.m.)

CHAIR MITCHELL: All right. We'll take questions on Commissioners' questions, but only if there are any such questions. I'll look over here. All right.

MS. GRUNDMANN: I have, I think, just two questions following up on some of Chair Mitchell's very helpful questions that have clarified far more about the transmission process that I knew before.

EXAMINATION BY MS. GRUNDMANN:

Q. She asked some questions about how generators will consider the total economics of a project when deciding whether to build a project.

And I think your response to that question was that the modeling included the transmission cost adder and still selected solar, correct?

A. (Maura Farver) That's correct.

Q. But I don't want to talk so much about modeling, but I want to talk about actual.

The proposal, with respect to the red zone, is to recover those costs I guess through base rates, is that where y'all would propose them, and then to recover them through customers?

A. The upgrades, because they're part of a local transmission expansion plan, would be recovered as other transmission upgrades are. I'm not the expert on cost recovery, but ultimately, these costs do come back to customers no matter whether it's through the red zone upgrades or through the PPA price or the asset acquisition price.

Q. Well, to the extent that -- just as -- hypothetical here, right.

If the generators -- third-party generators, themselves, were forced to bid their projects inclusive of some portion of the red zone, however you slice that up, customers could, could they not, potentially see lower costs, depending on how those generators economically looked at the totality of the project? It could be higher or lower?

A. I -- can you repeat the question?

Q. Yeah. Let me see if I can ask it better. The red zone projects, if you recover them through customers and rates, I think the total number was $540 million.

You would recover those dollar for dollar from customers if they go through rates, fair?

A. Subject to check, yes.

Q. And then I think the sort of discussion was, is that as we look at multiple clusters, the levelized cost of transmission will go down. And so if you looked at, over the course of multiple clusters, projects that were gonna interconnect into the red zone, if you were to, sort of, allocate that $540 million to all of those projects, those third-party generators would have to figure out what their ultimate PPA price would be, inclusive of those transmission costs?

MS. KELLS: Objection. The panel can't speak to why the generators are going to bid. And this is beyond the scope of their testimony and the discussion with Chair Mitchell.

CHAIR MITCHELL: All right. I'm gonna sustain. Ask a different question.

MS. GRUNDMANN: That's okay. Those are all the questions that I have.

MR. JIMENEZ: I'm sorry. Nick Jimenez with Southern Environmental Law Center. I thought we were going in alphabetical order. Just a couple of questions following on Commissioner Kemerait's questions yesterday and Chair Mitchell's questions this morning.

EXAMINATION BY MR. JIMENEZ:

Q. So Ms. Farver confirmed that if a transmission project is not in the DISIS baseline, the costs would be assigned to the triggering generation project, right?

A. (Maura Farver) To the -- it could be more than one generating project contributing to that.

Q. Good clarification. Thank you.

And earlier this morning you testified that if projects are included in the base plan for the DISIS, then the assumption would be that the interconnection customer would not pay?

A. That is correct.

Q. Okay. Thanks. So won't assigning the cost of the RZEP projects to solar generation for the purposes of the 2022 solar procurement increase the apparent cost of the solar resources that are procured in the red zones?

A. In the evaluation process, those costs are going to be ascribed in the ranking. So if the red zone upgrades are approved and in the base case, the ultimate interconnection agreement my not assign that cost to the generator. But for evaluation purposes in the RFP, we're taking a portion of the cost that they would be allocated into consideration when we rank the projects.

Q. Okay. And couldn't that potentially trigger a downward adjustment of the final procurement amount under the volume adjustment mechanism, depending on how they line up against the solar reference case -- or cost?

A. If you're assuming the costs are very high and proportionately drag the weighted average down, that is possible.

Q. That's all.

MS. CRESS: Good morning. Christina Cress for CIGFUR. I've got a couple of follow-up questions.

EXAMINATION BY MS. CRESS:

Q. Ms. Farver, I believe you were testifying in response to Chair Mitchell when you testified that the solar proposed in the Carbon Plan was economically selected; is that right?

A. (Maura Farver) Yes.

Q. Is it your testimony that all of the solar proposed in Duke's four portfolios in the Carbon Plan was economically selected?

MS. KELLS: Objection. It's a question for the modeling team.

MS. CRESS: Chair Mitchell, she testified in response to you that the outputs were economically --

CHAIR MITCHELL: I'm gonna overrule the objection. Ask the question again.

Q. Would -- I'm just trying to understand your testimony. You testified that the solar in the Carbon Plan was economically selected. And I just asked you about that and you said yes, that was your testimony.

I'm asking you, do you mean that all of the solar in the four portfolios in the Carbon Plan was economically selected?

A. I would prefer the Modeling Panel confirm that, because perhaps "all" is too inclusive. Subject to check, there were some projects that were assumed into the model before economic selection occurred from past legal obligations. I think Green Source Advantage. But this is a modeling detail that I don't think I have the answer to.

Q. Okay. I'm happy to hold it for Modeling Panel rebuttal. Thank you.

Moving on, just to be clear, the plan is for 100 percent of the RZEP upgrade costs to be allocated to the load-serving entity, correct?

A. I believe so.

Q. And by extension, that means the load-serving entity's customers?

A. Yes. This is really Ms. Bateman's area of expertise, but.

Q. Will any of the RZEP upgrades be used to wield power to serve load outside of DEP's or DEC's North Carolina service territories?

A. (Sammy Roberts) That's -- that's not planned.

Q. It's not planned, perhaps; is it possible that it will occur?

A. There could be exports that impact power flows on any portion of the transmission system.

Q. Is it possible that the RZEP upgrades could be used to wield power to serve load outside of North Carolina?

A. Like I said, there's -- for exports, any portion of the transmission system could be used to facilitate that export.

Q. Can you help us understand why costs will not be allocated to the solar developer or a group of solar developers whose projects are seeking interconnection and whose projects will be facilitated by the RZEP upgrades?

A. Could you repeat the question?

Q. Sure. Can you help us understand why the costs of the RZEP upgrades will not be allocated to the developer or a group of developers whose projects will be more easily facilitated through these RZEP upgrades?

A. Yeah. So currently, with our cost allocation methodology, we had to follow those approved FERC cost allocation methodologies. And also with respect to state, we had to follow the state interconnection procedures and associated cost, unless some different approved program is established associated with that cost allocation.

I mean, ultimately, you know, the customer is gonna be the beneficiary, like I was stating yesterday with respect to that solar reliably being able to be delivered to storage where it's located, or reliably being delivered to load, that storage is gonna serve peak load, that solar energy is gonna serve load. And so reliably delivering that energy to customers, the customers' benefit, there's also benefits with respect to -- Commissioner Hughes brought up yesterday resiliency with respect to, you know, making it through extreme events, recovering from extreme events.

There is also benefits with respect to lowering line losses. There's multiple benefits to these projects that I tried to quantify somewhat in the testimony.

Q. So for the state jurisdictional projects, this Commission could direct that a different cost allocation methodology be used; is that correct?

A. So I'll refer back to our CPRE program, I guess, where the allocation of those transmission costs to facilitate the interconnection of a certain amount of solar, as stated in law, we needed to ensure that the transmission -- looking at aggregate cost, that the transmission was managed such that it wouldn't be a hurdle to interconnection, and we selected the best bids for the customers.

Q. Okay. So I was really just looking for a yes or a no there, if you could.

A. Could you repeat your question?

Q. For state jurisdictional projects, could this Commission direct that a different cost allocation methodology be used for these network upgrade costs?

A. So they could stipulate an order, something similar to our CPRE program.

Q. I think that's it for me. Thank you.

MR. SNOWDEN: Chair Mitchell, I have a few. Not as many as you would expect, but I have a few questions on Commissioner questions. But first, I understand that this Commission does not generally permit recross, but when Duke's counsel did redirect of Mr. Roberts yesterday, he changed one of the answers that he had provided to me on cross examination without really any explanation. So I would request the opportunity to very briefly follow up on that.

CHAIR MITCHELL: Let's do this. Let's stay with the questions on Commission's questions for now.

MR. SNOWDEN: I can come back on to it on rebuttal, that's also fine.

CHAIR MITCHELL: Right. And I would ask this. When we recess, why don't you confer with Duke's counsel, let's look at the transcript, look at the film, and let's figure out what's going on. You-all work it out. And then if you need to bring it back, we'll deal with it on rebuttal. You'll have an opportunity to deal with it then.

MR. SNOWDEN: Okay. Thank you.

EXAMINATION BY MR. SNOWDEN:

Q. Let's first, then, I will follow up on, generally, Chair Mitchell's and other Commissioners' questions on cost allocation.

Mr. Roberts, if I can paraphrase a lot of what's been discussed here, you tell me if you agree with this, that you've testified or agreed that, if the entire cost of the red zone upgrades was allocated in an interconnection study to a smaller subset of projects, less than approximately 5,400 megawatts, that those upgrades would facilitate, it would distort, sort of, the apparent price of those upgrades with respect to those projects; would you agree with that?

A. Yes.

Q. Okay. And are you -- you're aware that the Public Staff has expressed concerns that the red zone upgrades will be constructed but not be fully utilized?

A. Yes.

Q. Okay. So if for purposes of RFP evaluation -- and, Ms. Roberts [sic], this may be a question for you.

If for purposes of evaluating projects in an RFP, the full costs of the red zone upgrades are allocated to a smaller set of projects as we discussed, wouldn't it be possible that those projects would not get selected in the RFP because of those additional costs?

A. (Maura Farver) Yes. It's all relative to the other projects they're being compared against.

Q. Understood. Thank you. But would you agree that that would increase the likelihood that the red zone upgrades would actually be underutilized?

A. Well, I think the point is that the red zone upgrades are not just for one procurement cycle, and this is really a longer term approach and a longer view of what our goals are. And so to look at just one specific procurement cycle is taking too narrow a view of what the red zone projects are enabling.

Q. Okay. Well, do you agree that that distorting effect of allocating the cost of the red zone upgrades to a smaller set of projects than they would ultimately facilitate could result in those upgrades being underutilized?

MS. KELLS: Objection. I let a questions go, but there was no question on underutilization with the Commission's questions.

MR. SNOWDEN: We're discussing -- there had been a number of questions on cost allocation and the impacts to the cost allocation, the -- what would happen if the full cost of the upgrades were assigned to a smaller subset of projects. This is my last question on this topic, so I just want to play that out, if I may.

CHAIR MITCHELL: All right. I'll overrule the objection.

MR. SNOWDEN: Okay. I'll try to ask it again.

Q. So, Ms. Farver, would you agree, though, that the allocation of the full cost of the red zone upgrades to a smaller set of -- subset of projects would increase the likelihood that those red zone upgrades would be underutilized?

A. I don't think that I would agree that it's necessarily increasing the likelihood of them to be underutilized. For this 2022 procurement cycle, it may make those few projects that are incurring red zone upgrades look less competitive. And so to the extent that they're less competitive, they may not be selected or would be less likely to be selected in this particular RFP cycle. But we haven't designed the evaluation methods and criteria for future procurement cycles.

Q. And I just want to clarify one more thing. You said that -- a few moments ago that the Company in the RFP plan to allocate a portion of the costs of the red zone upgrades to projects in the evaluation stage.

Can you clarify whether the Company plans to allocate the full cost of the red zone upgrades to projects in the RFP or only a portion of them?

A. A portion of the upgrade, that is what it would have been assigned but for the facility -- or the upgrade becoming a contingent facility. So if it's allocated in phase 2 across multiple projects, it will receive a portion of that allocation, and that is the number that would be used in the evaluation for the 2022 RFP.

Q. Okay. I think I understand. I just want to try to clarify.

So if, hypothetically, the full cost were, say, $500 million, the full cost of the red zone upgrades, what you're saying is the full $500 million would be allocated to projects in the first DISIS cluster?

A. Not -- not quite. So not every project is going to hit every single red zone upgrade. And so when we're going through the DISIS process, a project may contribute to two or three, any number. It's dependent on the project, obviously. And so to the extent that it contributes to those particular upgrades, it would be assigned a portion of that cost commensurate with the other projects that are contributing to the upgrade.

So for projects that are in the 2022 RFP, the portion of the pieces of the RZEP that it contributes to would be assigned in the evaluation process, even if the red zone projects have been approved and will end up becoming contingent facilities in the ultimate interconnection agreement.

Q. Would it be possible for the Company to -- in the 2022 RFP and DISIS to, for evaluation purposes, only allocate a portion of the full cost of the red zone upgrades to projects in 2022 and allocate the remainder to future projects?

A. I think that is an interesting question to explore for a 2023 RFP where we're still designing the rules. I don't know that we have that flexibility in our 2022 RFP rules at this point in time. But I'd like to check with counsel. I might not be the expert on all of the RFP -- I would like to recheck the RFP details to make sure that we don't have that flexibility, but I don't think that's allowed for in the 2022 RFP.

Q. Okay. Would you agree that the 2022 RFP doesn't exactly say, in any detail, how upgrade costs are going to be allocated for purposes of evaluating projects?

A. I'd like to check the RFP rules. I believe this is part of the quantitative evaluation that the IE and the evaluation team have worked out together and has been established. I don't know if it's explicitly written in the RFP rules.

Q. Okay. Thank you, Ms. Farver. All right. I just want to -- I've got a few questions that I think will -- these are following up on questions that

Commissioner Clodfelter and Commissioner Duffley asked yesterday that I'm hopeful will clarify a couple of things.

Commissioner Duffley asked about -- this is for Mr. Roberts, I believe. Commissioner Duffley asked about the net benefit analysis that the Company had conducted of the red zone upgrades.

Do you recall that?

A. (Sammy Roberts) Yes.

Q. Mr. Roberts, would you agree that the Company has actually filed some information about cost benefit analysis of at least some of the red zone upgrades in the Commission docket related to the multiyear rate plan application?

A. Yes, that's my understanding. And they used a -- or we used a reliability based model. There's two different models associated with the industry-wide tool that's utilized for cost benefit analysis for projects. One is a reliability base model, one is an asset replacement model. And we reference the asset replacement model, and that's what we utilized in my testimony.

Q. Okay. Thank you. And so at least some of that information was made available to the Commission in connection with the July 25, 2022, technical conference; is that right?

A. That's my understanding.

Q. Okay. Thank you. And this is to follow up on Commissioner Clodfelter's questions about the TPC process and how it relates to South Carolina.

So we don't need to get the OATT out unless you want to, but would you agree, Mr. Roberts, that in the Attachment N-1 to the OATT, it basically states that the NCTPC process, even though it's called the NCTPC process, actually handles local transmission planning for Duke's entire transmission system in North and South Carolina?

A. That's correct. It does cover our North Carolina -- excuse me, North Carolina and South Carolina areas.

Q. Okay. And it acknowledges the resource planning authority of both this Commission and the South Carolina PSC in the OATT, doesn't it?

A. That's correct.

Q. Okay. And, Mr. Roberts, would you agree that -- well, are you familiar with the South Carolina regional transmission planning process?

A. Yes. That's -- that would be analogous to

SERTP.

Q. Okay. So the South Carolina regional transmission process is a similar organization that Dominion Energy South Carolina and Santee Cooper participate in, right?

A. That's correct. It's their regional transmission planning group.

Q. But Duke doesn't participate in that, right?

A. We have. I mean, if you're talking about any kind of interregional SERTP and -- SERTP can participate.

Q. Understood. So both the NCTPC and the SCRTP all participate in the SERTP, the Southeast Regional Transmission Planning process?

A. So that's not quite correct. So NCTPC is a local transmission planning group, and outputs from that group do flow into the SERTP model. Outputs from the DEC and DEP transmission planning groups flow into the SERTP model. Also the South Carolina Reliability Transmission Planning group outputs from -- basically, you have to have the correct inputs into every model, transmission planning model, all over the eastern interconnection for the results to be valid.

Q. Understood. And so all I'm trying to do is clarify that, when it comes to transmission -- FERC-jurisdictional transmission planning for Duke's North and South Carolina service territories, the NCTPC is the place, right?

A. That's correct. And then the next level would be the SERTP.

Q. Okay. And Commission Clodfelter also had a question, I believe, about the requirement to get a CECPCN to authorize construction of transmission facilities in South Carolina; do you recall that?

A. Yes, I do recall that.

Q. And would you agree that, in South Carolina, as in North Carolina, a CECPCN is only required for the construction of new transmission lines, not for the upgrades of existing lines?

A. Subject to check, my understanding is that above 161 kV, you do have to have that CPCN in South Carolina for an upgrade. That's -- subject to check, that's my understanding.

Q. Okay. Thank you. Those are all the question I have.

CHAIR MITCHELL: Public Staff?

MR. JOSEY: Just a few.

EXAMINATION BY MR. JOSEY:

Q. Mr. Roberts, you remember your conversation with Commissioner Clodfelter regarding the Roxboro plant and installing a static VAR compensator versus a synchronic condenser, if I said that correctly?

A. Yeah. So it was -- if I remember Commissioner Clodfelter's question correctly, it was have you considered a static VAR -- converting a unit at Roxboro to static VAR -- I'm getting confused now. Synchronous condenser versus installing a new static VAR compensator.

Q. Yes, I believe that was the question.

And Commissioner Clodfelter also spoke about the -- about Roxboro and its remaining a level of undepreciation or its current book value; do you recall that?

A. Okay. I don't recall that part of the conversation, but I'll take your word for it. Yesterday was a tough day for me.

Q. Fair enough. Do you happen to know what the current book value of the Roxboro plant is?

A. I do not.

Q. Okay. Would witness Bateman be the one to answer that?

A. Yes.

Q. Okay. Thank you. And I'm not sure if this is for Ms. Farver or Mr. Roberts, but it's going off a line of questioning from Commissioner Kemerait on the red zone upgrades being in the baseline and its effect on projects going through DISIS and in future studies.

So Commissioner Kemerait pointed out that facilities being studied in this DISIS do not have to take part in the 2022 procurement; is that correct?

A. (Maura Farver) That's correct, they don't have to be.

Q. And if they decide to forego the 2022 procurement, or not select it, those projects could decide to sell to a commercial customer either on or off system; is that correct?

A. That's correct.

Q. And the project would be responsible for the upgrades allocated to them?

A. That is correct. Is this assuming they're a FERC-jurisdictional customer, then --

Q. Either one.

A. -- if they're selling our system?

Q. If they're FERC jurisdictional or if they're state jurisdictional, they're still allocated the costs initially?

A. Correct.
Q. And then if it's for jurisdictional, they have the ability for reimbursement?
A. That's my understanding.
Q. Okay. And if it's state jurisdictional, they have to pay their own upgrades?
A. Correct.
Q. But in either situation, this Commission would be able to look at those upgrades in determining whether or not to grant a CPCN; is that your understanding?
A. Yes, I believe so.
Q. But once the red zone upgrades are in the baseline, those projects would not be assigned or allocated any cost for upgrades?
A. That is correct. Those upgrades would become contingent facilities.
Q. Okay. And so therefore, when the projects that were not entering into a Duke procurement, they would not -- when they would come in for a CPCN application, the Commission wouldn't have those upgrade costs to look at for that particular facility, correct?
A. I believe that's correct.
Q. Another way to state it is that, since they

were no longer allocated the cost because the red zone upgrades were in the baseline, those costs would not be available for the Commission to consider when determining a CPCN?

A. I suppose the cost would not be specifically assigned, but the Commission would be able to see that they are benefitting from those upgrades in their evaluation of whether it was in the public interest.

Q. Okay. And so a project that was -- that is benefitting from those upgrades in order to interconnect from the red zone upgrades that were in the baseline, it could potentially sell off system to -- if it were granted a CPCN, it could potentially sell off system?

A. Yes. If the Commission had a CPCN for a FERC-jurisdictional project, and they saw that it was benefitting from those red zone upgrades, the Commission could choose to grant the CPCN, and it would sell off system, then, presumably for that project.

Q. Okay. Thank you.

A. (Sammy Roberts) That project would have to request point-to-point service, though, and thus pay part of the revenue requirement through that firm point-to-point service.

Q. Thank you. I'm gonna move on to some of Chair Mitchell's questions.

Mr. Roberts, do you know when the OSC will be voting on this current local transmission plan, with the red zone upgrades presumably in it?

A. Yeah. So it's currently not penciled in the schedule. But once again, we're looking at having TAG stakeholder meeting to discuss the supplemental studies with the red zone projects October 19th, subject to check. And then progress from there to include these projects in the 2022 local transmission plan, have it in the draft report, post it, and then vote toward the end of the year, and subsequent posting for the final report in January.

Q. Okay. So it would be before the end of this year?

A. That's correct.

Q. Okay. And if this Commission is not issued an order on the Carbon Plan before, I guess, December 31, 2022, would the OSC go ahead and vote on the local transmission plan?

A. Right. I mean, really, the final report, when it gets posted, that's the official local transmission plan. So, you know, I would like to say it's contingent upon the Commission's acknowledgement, and we would -- you know, that would definitely be support evidence that the projects are prudent from a Carbon Plan perspective.

However, the bottom line is we know these projects are gonna be needed for us to meet the Carbon Plan, period. And so we would look to try to move this forward.

Q. So regardless of what this Commission determines, it would just be a piece of evidence in trying to determine whether or not --

A. It would be a decision point for us as NCTPC.

Q. And you -- Mr. Roberts, you spoke about the current list of red zone expansion plan projects being in your rebuttal testimony at Transmission Panel Exhibit 3; is that correct?

A. That's correct.

Q. I don't want to go into rebuttal testimony, but just for clarifying purposes, the Public Staff disagrees with three of the projects that Duke currently includes in that plan as shown on Exhibit 3, correct?

A. So out of the 15 that the supplemental study supported -- out of the 15 of the 18 original projects that the supplemental study supported, an additional three were -- it was recommended by the Public Staff to delay. And they said in their direct testimony that you can provide information in your rebuttal testimony if you want to try to persuade otherwise.

But that was the Camden-Camden DuPont line, the Erwin-Fayetteville 115 line, which was one of the original Friesian upgrades, and the Rockingham-West End west line, I believe was the other one.

Q. I believe it was the Clinton 100 kV --

A. Oh, yeah, sorry, Clinton --

Q. The Erwin to Fayetteville --

A. It's all running together.

Q. -- 115 --

A. That's correct. Clinton --

Q. -- the Camden to Waterly [sic] --

CHAIR MITCHELL: All right. Hang on. For purposes of clarity in the record, you guys were talking over each other. So let's make sure -- let's identify the lines and identify them clearly.

THE WITNESS: I can state the three. So it's the Erwin-Fayetteville 115 kV line; the Clinton 100 kV line, and the Camden-Camden DuPont

115 kV line.

Q. I have the Camden-Waterly [sic] line; is that -- no?

A. No, I don't think that's correct. Subject to check.

Q. We can have Mr. Metz confirm which line it is on his -- during his --

CHAIR MITCHELL: All right. That sounds like a good plan.

Q. Okay. And you both stated, in response to several questions, that there were 181 megawatts left in the transition cluster study.

A. (Maura Farver) Subject to check.

Q. Okay. Are you talking about the transition cluster or are you talking about the tranche 3 resource solicitation cluster?

A. The transitional cluster.

Q. Okay. And the transition cluster study phase 2 report came out on August 28, 2022, subject to check?

A. Subject to check.

Q. Okay. And in those reports, which I don't have copies of at this moment, but had to pull it up on DEP and DEC's respective OASIS sites, it appears that there are 150 megawatts of solar in that report in DEP and 176.5 megawatts of standalone solar in DEC coming out of that report.

Have any of those projects dropped out?

A. (Sammy Roberts) Subject to check, I believe so, but I'll have to check.

Q. Okay. And then there wee another 181 megawatts in tranche 3?

A. (Maura Farver) I would like to check that.

Q. Was it 118 maybe?

A. I'm sorry, do you mean the number of projects that signed a PPA in tranche 3.

Q. In tranche 3, just how many were awarded bids and how many megawatts were --

A. I believe it's 155 megawatts.

Q. That's right. Thank you. And one last question, Ms. Farver.

Are you aware that Friesian has submitted an application for CPCN before the Commission as a state jurisdictional project?

A. I knew that they submitted a CPCN. I don't know the details.

Q. Okay.

MR. FREEMAN: Chair Mitchell, I'd just

like the Commission to take judicial notice of Friesian's SP-8467, Sub 0 docket, and the filings within that docket.

CHAIR MITCHELL: All right. We will -- the Commission will take notice of the docket.

MR. FREEMAN: That's all the questions I have.

CHAIR MITCHELL: All right. Duke?

MR. JIRAK: Chair Mitchell, we had a number of questions, but looking at the clock and reading the tea leaves in the room, we think we can handle most of those, if needed, on rebuttal. So at this time, we'll pass on the opportunity.

CHAIR MITCHELL: All right. With that, I don't believe we've had any exhibits -- well, did we have any entered exhibits -- let me do this --

MS. KELLS: Chair Mitchell, I think we did.

CHAIR MITCHELL: -- motion. I'll take them.

MS. KELLS: But I'll do it again. I -- just out of an abundance of caution, Companies move that the five exhibits, with Exhibit 5 being marked confidential, be admitted into the record as well as this panel's direct testimony summary.

CHAIR MITCHELL: All right. The testimony -- the testimony summary will be copied into the record at the appropriate time, and the exhibits to the testimony will be accepted into evidence and number 5 marked as confidential.

Any intervenors have documents they'd like to move in?

MR. SNOWDEN: Chair Mitchell, I believe that we already moved them in, but I could definitely have forgotten. So out of an abundance of caution, CPSA would ask that CPSA Modeling Panel Direct Cross Examination Exhibit 1 be moved into evidence if it has not -- I'm sorry. Transmission -- I'm sorry. CPSA Transmission Panel Direct Cross Examination Exhibit 1 be moved into evidence if it has not been already.

CHAIR MITCHELL: All right. Your motion is allowed.

MS. CRESS: Chair Mitchell, CIGFUR II and III would move that its Transmission Panel Direct Cross Examination Exhibits 1, 2, and 3 be entered into the record and moved into evidence if they have not already been.

CHAIR MITCHELL: Motion is allowed.

MR. JOSEY: And the Public Staff would move to have Public Staff Transmission Panel Direct Cross Exhibits 1 through 3 moved into the record.

CHAIR MITCHELL: Your motion is allowed, Mr. Josey. And Mr. Smith?

MR. SMITH: Chair, if it's not already been moved into the record, Avangrid Renewables requests moving into the record Avangrid Renewables LLC Transmission Panel Direct Cross Examination Exhibit 1.

CHAIR MITCHELL: All right. Motion is allowed.

(All Transmission Panel exhibits were previously entered into the record in Volume 17.)

CHAIR MITCHELL: All right. With that, you-all may step down. Ms. Farver. It seemed like they want to stay up here longer. Mr. Roberts, yeah, you need to stay.

THE WITNESS: (Sammy Roberts) I'll have to grab another notebook.

CHAIR MITCHELL: Okay. And, Duke, call your next witnesses.

MR. JIRAK: Just one minute here to get reorganized. Thank you.

(Pause.)

CHAIR MITCHELL: Okay. All right, gentlemen. Mr. Roberts, you are already under oath. Mr. Holeman, let's get you under oath.

Whereupon,

JOHN SAMUEL HOLEMAN, III AND SAMMY ROBERTS,

having first been duly sworn and/or previously sworn,

were examined and testified as follows:

MS. DEMARCO: Thank you, Chair Mitchell. This is Tracy DeMarco on behalf of Duke Energy.

DIRECT EXAMINATION BY MS. DEMARCO:

Q. Mr. Holeman, would you please state your full name and business address for the record?

A. (John Samuel Holeman, III) Yes, I will. My name is John Samuel Holeman, III. I go by Sam. My business address 526 South Church Street, Charlotte, North Carolina.

Q. And by whom are you employed and in what capacity?

A. I'm employed by Duke Energy Corporation. I'm vice president of transmission system planning and operations.

Q. And can you please briefly describe your role and responsibilities at Duke Energy?

A. Sure. The teams I lead manage the real-time operations in our energy control centers. They also manage and direct the support functions, system operations, engineering system operations training. They also lead the operational technology support functions, they lead the transmission planning functions, and they lead the compliance functions associated with operations and planning NERC standards. They also support the open access transmission tariff functions within Duke Energy.

Q. Thank you, Mr. Holeman. And do you have any other additional industry experience that's relevant to your testimony today?

A. I have had the opportunity to serve as a member and subsequently chair and vice chair of the SERC operating committee. I've had the opportunity to serve as a number and subsequently chair and vice chair -- vice chair and chair of the NERC operating committee. I've had the opportunity to serve in the NERC event analysis subcommittee as a member and subsequently as chair. And I currently serve as the chair of the industry advisory group for EPRI's operation and planning group.

Q. Thank you, Mr. Holeman. Turning briefly to Mr. Roberts.

And just for the record, can we please confirm, Mr. Roberts, that you are the same Mr. Roberts who was just testifying as part of the Transmission Panel?

A. (Sammy Roberts) Yes, I am.

Q. Thank you. Mr. Holeman, did you cause to be prefiled in this docket direct testimony consisting of 90 pages and one exhibit?

A. (John Samuel Holeman, III) Yes, I did.

Q. And do you have any changes to your direct testimony or exhibits at this time?

A. We do have one change. Page 4 of the Reliability Panel testimony, line 2, the change is from 2007, 2-0-0-7, to 2017, 2-0-1-7.

Q. Do you have any other changes to your testimony?

A. No, I do not.

Q. If I were to ask you the same questions today that appear in your prefiled direct testimony, would your answers be the same?

A. That is correct.

Q. Any your testimony and exhibits did not include any confidential information, correct?

A. No, they didn't.

MS. DEMARCO: Chair Mitchell, I would ask that the Reliability Panel's direct testimony be entered into the record as if orally given from the stand.

CHAIR MITCHELL: All right. Motion is allowed.

(Whereupon, the prefiled direct testimony of John Samuel Holeman, III and Sammy Roberts was copied into the record as if given orally from the stand.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:	)	
Duke Energy Progress, LLC, and	)	**DIRECT TESTIMONY OF**
Duke Energy Carolinas, LLC, 2022	)	**DEWEY S. ROBERTS II AND**
Biennial Integrated Resource Plan	)	**JOHN SAMUEL HOLEMAN III**
And Carbon Plan	)	**FOR DUKE ENERGY**
	)	**CAROLINAS, LLC AND DUKE**
	)	**ENERGY PROGRESS, LLC**

TABLE OF CONTENTS

Q. MR. HOLEMAN PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH DUKE ENERGY CORPORATION.

A. My name is John Samuel Holeman III (Sam), and my business address is 526 S. Church Street, Charlotte, North Carolina, 28202. I am the Vice President of Transmission System Planning and Operations for Duke Energy Corporation.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from Clemson University in 1983 with a B.S. Degree in Electrical Engineering and in 1985 with a M.S. Degree in Electrical Engineering. I also obtained a Master of Business Administration Degree from Queens University in 2014. I am a registered Professional Engineer in North Carolina and South Carolina. I am also a member of the Institute of Electrical and Electronics Engineers. I am currently recognized as a Certified System Operator by NERC.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A. I joined Duke Energy in 1985 and have held various engineering and management positions in System Planning and Operations of increasing responsibility throughout my career. These positions include: Energy Management System Application Engineer; System Operating Center Engineer; System Operator; Manager, System Operating Center; Director, System Operating Center; and Director, Engineering and Training.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. In my current position, as Vice President – System Planning and Operations, I am responsible for compliance with the North American Electric Reliability Corporation ("NERC") and Federal Energy Regulatory Commission ("FERC") Bulk Electric System safety and reliability regulations applicable to Balancing Authority, Transmission Operator, and Transmission Service Provider functions, as well as planning and operations for Duke Energy's regulated electric jurisdictions serving in the states of North Carolina, South Carolina, Florida, Indiana, Ohio, and Kentucky.

I have also been extensively involved with and now manage the ongoing NERC, SERC Reliability Corporation ("SERC"), and ReliabilityFirst ("RF") Bulk Electric System reliability compliance obligations for Duke Energy's regulated electric utilities. I served as Chair of the SERC Operating Committee from 2007 through 2009 and was also Chair of the NERC Operating Committee from 2009 through 2011. I also served as the NERC Event Analysis Subcommittee Chair from 2012 to 2014 and served on the NERC Essential Reliability Services Task Force from 2014 to 2015.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes. I testified before the North Carolina Utilities Commission ("Commission") in the 2016-2017 review of North Carolina's implementation of the Public Utilities Regulatory Policy Act ("PURPA") for Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, the

"Duke Energy" or the "Companies") in Docket No. E-100, Sub 148 as well as in the Companies' 2019 avoided cost proceedings before the Public Service Commission of South Carolina ("PSCSC"), Docket Nos. 2019-185-E an 2019-186-E.

Q. **MR. ROBERTS, PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH DUKE ENERGY CORPORATION.**

A. My name is Dewey S. Roberts II (Sammy), and my business address is 3401 Hillsborough Street, Raleigh, North Carolina, 27607. I am the General Manager, Transmission Planning and Operations Strategy for Duke Energy Corporation.

Q. **ARE YOU THE SAME SAMMY ROBERTS WHO PROVIDED TESTIMONY AS PART OF THE TRANSMISSION PANEL?**

A. Yes.

Q. **DID YOU DESCRIBE YOUR EDUCATIONAL BACKGROUND, PROFESSIONAL QUALIFICATIONS, BUSINESS BACKGROUND AND EXPERIENCE, AND CURRENT RESPONSIBILITIES IN YOUR TESTIMONY FOR THE TRANSMISSION PANEL?**

A. Yes.

Q. **WOULD YOU LIKE TO SHARE ANY ADDITIONAL INFORMATION REGARDING YOUR BACKGROUND THAT IS PARTICULARLY RELEVANT TO YOUR TESTIMONY ON THIS RELIABILITY PANEL?**

A. The majority of my 32-year career with the Companies has been in the area of System Operations with 15 years as Manager or Director of an Energy Control

Center. I was also recognized as a Certified System Operator by NERC from 2006 through 2007 and 2019 through 2021.

Q. IS THE PANEL SPONSORING ANY EXHIBITS IN YOUR DIRECT TESTIMONY?

A. Yes. We are sponsoring **Reliability Panel Exhibit 1** which provides graphics and figures presented in our testimony in a larger, more readable format.

Q. MR. HOLEMAN, WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. As we advance energy transition and exit coal generation, executing the Carolinas Carbon Plan ("Carbon Plan") will be transformative to the Companies' generation fleets and underlying grid, connecting unprecedented amounts of new supply-side resources and leveraging demand-side tools necessary to retire significant amounts of coal-fired generation and achieve the carbon emission reduction targets important to the Companies, their customers in the Carolinas, and established by North Carolina Session Law 2021-165 ("HB 951"). DEC and DEP system operations functions must maintain a secure and reliable electric grid every minute of every day through this transformative period of energy transition, while meeting our core obligations as an electric service provider and the provisions of HB 951 to maintain or improve upon the adequacy and reliability of the existing grid.

The purpose of my testimony is to provide an overview of the role and obligations of real-time operations in maintaining a secure, adequate, and reliable grid and meeting mandated NERC Reliability Standards. My testimony will also provide a broad industry perspective on the challenges system operations functions face maintaining adequacy and reliability through this grid transformation and planned greater reliance on low carbon resources during the transition. I will describe what the Companies' system operations functions are learning from industry peers, industry operating experience and events, and how those learnings are informing the Companies' real-world thinking and approach in managing reliability as their systems transitions to lower CO_2 emissions through Carbon Plan execution from the view of System Operators.

Q. MR. ROBERTS, WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In order to effectuate an orderly energy transition and meet the requirements of HB 951's mandate that the Carbon Plan must "*maintain or improve upon* the reliability of the existing grid."[1] To meet that requirement, appropriate planning through Carbon Plan modeling and analysis is essential, including validating the fundamental reliability of proposed portfolios. More importantly, the results of portfolio planning, modeling, analysis and validation must have a connection to the real world of System Operators who manage anticipated, unanticipated and emergent events.

The purpose of my testimony is to provide a System Operator's perspective of the reliability analysis completed by the Companies in development of the Carbon Plan and illustrate the real-world examples of risks associated with that analysis as the Companies retire over 8,400 MW of coal-fired generation, representing approximately 20% of winter capacity for the

[1] N.C. Gen. Stat. § 62-110.9(3) (emphasis added).

Companies' combined systems[2] and replace with higher levels of intermittent renewables and energy-limited storage as well as new gas generation through Carbon Plan execution. I will also describe the real-world and practical challenges of executing the alternate plans and recommendations proposed by certain intervenors and address how those alternate plans fall short in ensuring reliability for customers.

Q. PLEASE SUMMARIZE THE KEY TAKEAWAYS OF YOUR JOINT TESTIMONY FOR THE COMMISSION.

A. The following are key takeaways from this panel:

1. The Companies are in the unique role of owning the obligation to serve customers securely and reliably, every minute of the day in all operating and weather conditions and meeting NERC reliability obligations to ensure the stability of the Bulk Electric System and broader Eastern Interconnection electric grid—no intervenors have this responsibility. The Companies are accountable to the Commission and their customers for ensuring the adequacy and reliability of the existing grid is maintained or improved, and the Carbon Plan approved by the Commission must be executable and appropriately manage operating and reliability risks.
2. NERC, as the entity responsible for reducing risks to the security and reliability of the North American grid, has clearly identified and is providing guidance on specific risks related to grid transformation and a changing

[2] Carbon Plan Executive Summary at 17.

resource mix, including the continued need for flexible gas resources to maintain reliability during this transformation.

3. Across the country, utilities are all doing the same thing—retiring coal units (and in some cases nuclear units) and adding renewables, batteries, and distributed and demand-side resources. Policy is driving system decarbonization and peer NERC system operations functions across the country are all planning for and already feeling the impact of systems relying less on centralized coal, nuclear, and natural gas units and more on variable energy resources, energy-limited storage, and demand-side resources.

   There is significant consensus on the reliability risks related to grid transformation. Further, impactful events have occurred and are occurring across the industry confirming how those risks are becoming reality by not purposefully planning for the resources needed to maintain reliability. This commonality creates opportunity to advance operational learning and solutions; however, it also may result in less ability to import non-firm energy on neighboring systems' resources to support adequacy and reliability of the grid in broad and prolonged events or in constrained operational conditions.

4. DEC and DEP system operations see two key elements as the Companies consider the industry perspective of grid transformation and plan to execute the Carbon Plan to reduce CO_2 emissions. First is having a robust and diverse resource mix to ensure System Operators have multiple tools in their

generation adequacy and reliability toolbox to deal with expected and unexpected operational conditions. There should not be an overreliance on any single technology, as *all* technologies—renewables, demand-side resources, batteries, nuclear, flexible gas resources—will be necessary to both reduce CO_2 emissions and maintain or improve upon reliability of the grid. Second, as the Companies retire over 8,400 MW of coal-fired generation by the end of 2035—representing approximately 20% of existing winter capacity for the combined systems[3]—and rely more on the sun to shine, the wind to blow, and batteries to be charged, the system operations functions must be acutely aware of having enough flexible replacement capacity with similar operational capabilities as coal units to meet NERC Reliability Standards, particularly in seasonal and extreme events.

5. The Companies ensured that reliability was appropriately analyzed in the development and modeling of proposed Carbon Plan portfolios, and the additional portfolio verification and reliability validation steps were critical to considering varying load and weather conditions.
6. As the Companies continue to retire coal units and increase solar, wind, and batteries on the system, there are real-world implications to system operations that must be factored into ensuring the adequacy and reliability of the grid and meeting NERC Reliability Standards, such as managing ramping, net-load peak, forecast uncertainty, and having adequate flexible and dispatchable operational reserves.

[3] Carbon Plan Executive Summary at 17.

7. From a System Operator's point of view, certain intervenors did not sufficiently consider the Companies' obligation to maintain or improve the adequacy and reliability of the grid and to meet NERC Reliability Standards in their alternate plans and recommendations nor did they evaluate risk or analyze their portfolios against real-world implications of a changing resource mix.

I. DUKE ENERGY'S RESPONSIBILITY TO ENSURE ADEQUATE POWER SUPPLY AND RELIABILITY OF THE GRID

Q. MR. HOLEMAN, IN YOUR VIEW, ARE ADEQUATE POWER SUPPLY AND GRID RELIABILITY IMPORTANT CONSIDERATIONS IN DEVELOPING A RESOURCE PLAN LIKE THE CARBON PLAN?

A. Yes. The Companies fulfill a federally-mandated and essential role to provide for reliable Bulk Electric System operations on behalf of communities, businesses, and customers in the North Carolina and South Carolina (collectively referred to as "the Carolinas") 24 hours a day, 365 days of the year. Moreover, the Carolinas electric system, as part of SERC electric reliability region, is interconnected to other reliability regions in North America, and the Companies are obligated to meet NERC requirements to collectively ensure the reliability and security of the Eastern Interconnect grid—from eastern Canada to the Gulf of Mexico, from the Atlantic Ocean to the Rocky Mountains and Texas border. As the Companies consider the long-term resource plans for DEC and DEP for the economic stability and viability of the region, this reliability obligation is a core objective in concert with the other planning objectives of CO_2 emissions reductions, cost, and executability.

As discussed by Witness Kendal C. Bowman, reliability is a core planning objective of the Companies' Carbon Plan and of the North Carolina General Assembly which tasked the Commission with "ensur[ing] any generation and resource changes ***maintain or improve upon*** the adequacy and reliability of the existing grid."[4]

The Companies' Carbon Plan takes unprecedented steps to analyze and plan for integrating solar and other clean energy technologies to achieve the interim 70% CO_2 emissions reductions target as well as the long-term carbon neutrality target set by HB 951. From my position as a System Operator, intentionally planning for reliability to ensure compliance with mandatory NERC Reliability Standards is critical to maintaining power supply adequacy and reliability as the Companies move forward in this important energy transition.

Q. DID ANY INTERVENOR PRESENTING ALTERNATIVE MODELING ADEQUATELY ADDRESS NERC RELIABILITY STANDARDS OR SUFFICIENTLY FOCUS ON ENSURING RELIABLE SYSTEM OPERATIONS?

A. No. Mr. Roberts will address this point later in this testimony, but it is important to note that none of the proposed alternative plans or corresponding comments filed by intervenors present any focused analysis of the Companies' obligations to comply with mandatory NERC Reliability Standards today as well as under future resource planning scenarios. The alternate plans presented by Synapse

[4] N.C. Gen. Stat. § 62-110.9(3) (emphasis added).

Energy Economics, Inc. ("Synapse") on behalf of the North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, the Sierra Club, and the National Resource Defense Council's ("NCSEA, et al.") (the "Synapse Report") and Gabel Associates, Inc. on behalf of Apple, Inc., Google, LLC, and Meta Platforms, Inc. ("Tech Customers") (the "Gabel Report") essentially just rely upon the Companies' planning reserve margin to assure reliability, which, for reasons described herein and in the Modeling and Near-Term Actions Panel (comprised of witnesses Glen Snider, Robert McMurry, Michael Quinto and Matthew Kalemba) testimony, is not sufficient to ensure reliability is maintained or improved during this period of accelerated energy transition.

Q. PLEASE EXPLAIN WHY THESE CONSIDERATIONS ARE CRITICALLY IMPORTANT FOR RESOURCE PLANNING.

A. To accomplish an orderly energy transition, the Carbon Plan takes unprecedented steps to plan for integrating solar and other clean energy technologies as part of developing the least-cost path to reaching the interim CO_2 emissions reductions target and in planning to achieve carbon neutrality by 2050. Ensuring ongoing system reliability and compliance with mandatory NERC Reliability Standards in the face of this challenging transition is non-negotiable for the Companies and for customers. To accomplish the legislature's express directive that resource changes on the path to achieving carbon neutrality must maintain or improve upon the adequacy and reliability of the existing grid, the Commission must also consider reliability as non-negotiable under HB 951 when assessing any Carbon Plan for approval. One of my roles in this testimony is to explain the reliability considerations that must be included in this assessment.

Q. PLEASE BRIEFLY DESCRIBE DEC'S AND DEP'S RESPONSIBILITIES RELATED TO THE NERC RELIABILITY STANDARDS.

A. The Energy Policy Act of 2005, as implemented by FERC under Section 215(c) of the Federal Power Act, established NERC as the Electric Reliability Organization to develop and enforce reliability standards. Any violations of NERC Reliability Standard requirements are subject to a civil penalty of up to $1,291,894 per violation for each day that it continues.[5]

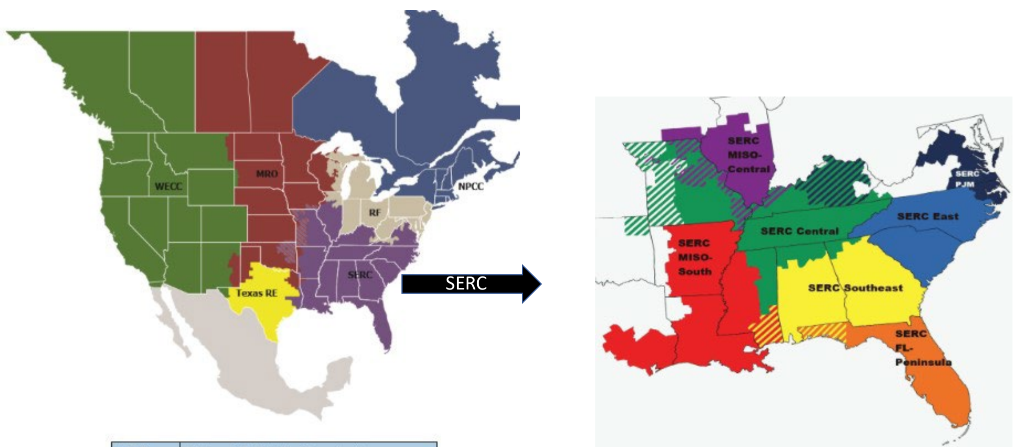
DEC and DEP are responsible for performing a variety of NERC reliability functions, and each function must maintain compliance with the NERC Operating Standards assigned to their functional entity. As Generator Owners and Generator Operators, DEC and DEP own, maintain, and operate generating units to supply reliable and affordable electricity to now approximately 4.5 million residential, commercial and industrial customers in the Carolinas. As Transmission Owners and Transmission Operators, DEC and DEP own, maintain, and operate transmission facilities in North Carolina and South Carolina, and are responsible for operating their transmission systems in

[5] 18 CFR § 385.1602(d); *see also* North Am. Elec. Reliability Corp, Rules of Procedure at 4 (effective May 19, 2022), *available at* https://www.nerc.com/AboutNERC/RulesOfProcedure/NERC-ROP-with-Appendices.pdf.

a reliable manner in compliance with applicable NERC Reliability Standards. As Transmission Service Providers, DEC and DEP administer the transmission tariff and provide Transmission Service to Transmission Customers under applicable Transmission Service agreements. As independent Balancing Authorities ("BAs"), the Companies must plan for and balance generating resources and power deliveries with customer demand for electricity in real time to avoid causing adverse power flow and/or frequency issues that could lead to instability or separation of the power system.

DEC and DEP operate as part of the SERC East subregion of the SERC reliability region of NERC as shown in Figure 1.

<u>Figure 1: NERC Regional Entities, SERC Subregions[6]</u>



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Sources: www.NERC.com, www.SERC1.org

In my role with the Companies, I have been responsible for reliable system operations and compliance with NERC Reliability Standards related to the

[6] Figure 1 is also replicated in Reliability Panel Exhibit 1.

Companies' BAs, Transmission Operator, and Transmission Service Provider functions and providing Reliability Coordinator services as a member of and agent for VACAR South within SERC. DEC and DEP NERC-Certified System Operators who have been job-task verified to perform NERC functions have the responsibility and clear decision-making authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System as required in applicable NERC Reliability Standards.[7] As DEC and DEP are vertically integrated utilities serving in the Carolinas, the Companies perform these functions under the oversight of this Commission and the Public Service Commission of South Carolina.

Q. PLEASE EXPLAIN THE COMPANIES' ROLES AS NERC BALANCING AUTHORITIES FOR THEIR BALANCING AUTHORITY AREAS.

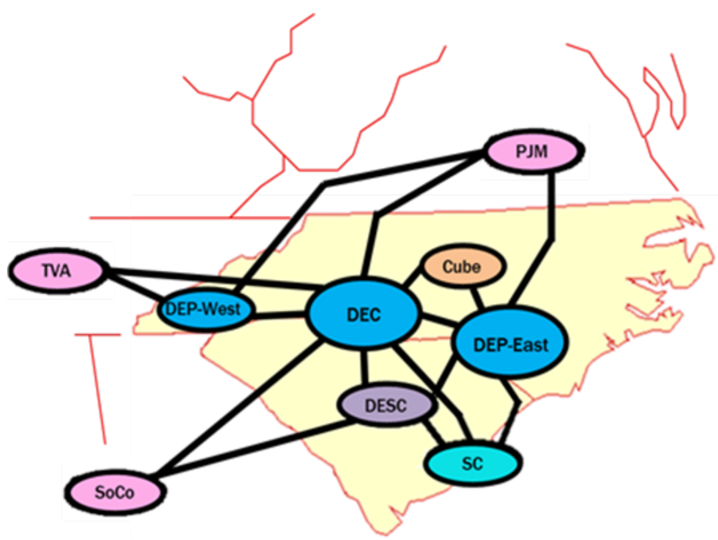
A. DEC and DEP are each independent registered NERC Balancing Authorities responsible for maintaining reliable operations on their systems, as well as managing power flows between their systems and other utility systems. DEC operates a fleet of approximately 22,369 MW (winter rating) of capacity resources to serve customers' energy needs on a 21,620 MW peak load system, while DEP operates approximately 16,390 MW (winter rating) of MW

[7] Responsibility and Authority Letter for Duke Energy System Operations identifies Bulk Electric System operational authority by Duke Energy's NERC functional registrants in support of specific NERC Reliability Standards relating to those applicable NERC functions, such as Balancing Authority, Transmission Operator, and Reliability Coordinator.

resources to serve its customers' energy needs on a 15,569 MW peak load system.

The DEC and DEP BAs independently control their respective generating fleets of "network resources" to meet system loads, as well as to maintain compliance with NERC Reliability Standards applicable to each BA. This includes maintaining interchange schedules between the DEC BA and the DEP BA, as well as other neighboring BAs, such as the Southern Company, Dominion Energy South Carolina and South Carolina Public Service Authority BAs to the south, the Tennessee Valley Authority BA to the west, and the PJM Interconnection BA to the north. My Figure 2 depicts the interconnected nature of the Companies' BAs with other neighboring BAs in the SERC region.

<u>Figure 2: DEC, DEP and Neighboring Balancing Authorities</u>



DEC, DEP and Neighboring Balancing Authorities (BAs)

DEC and DEP are each subject to mandatory NERC regulations, requiring the Companies to independently balance their respective systems and to provide reliable "firm native load service" to meet customers' electricity needs. The fundamental role of the BA is to manage load, generation, interchange, and operating reserves to ensure balance within the BA footprint and to minimize impacts from energy imbalance. The BA balances and factors in what has happened in the recent past, what is happening now, and what is forecasted to happen over the course of the next couple of days. Additionally, the BA looks out over upcoming weeks, months, and seasons to ensure generation adequacy with regards to forecasted load, generation availability, and operating reserves.

Q. PLEASE EXPLAIN THE IMPORTANCE OF NERC'S BAL STANDARDS AS THEY APPLY TO MAINTAINING SYSTEM RELIABILITY.

A. Each BA is responsible for independently complying with its mandatory NERC obligations, including providing its share of frequency support for the Eastern Interconnection, and by definition, maintaining demand and resource balance within its Balancing Authority Area. A BA must purposefully plan and dispatch its generating fleet to ensure compliance with NERC BAL Standards and cannot rely on unscheduled power flow from neighboring BAs to meet its obligation to maintain demand and resource balance and, thus, the NERC BAL Standards are designed to discourage and in effect, prohibit this behavior. Together, the BAL-001, BAL-002, and BAL-003 Reliability Standards[8] are designed to

[8] NERC Balancing ("BAL") Reliability Standards, https://www.nerc.com/pa/Stand/Pages/ AllReliabilityStandards.aspx (last visited Aug. 18, 2022).

enhance the reliability of each Interconnection by mandating every BA to balance generation, interchange, and load and maintain interconnection frequency within strict predefined real-time technical and time limits under all conditions.[9]

The BAL Standards are important Reliability Standards because they regulate a BA's real-time performance with respect to maintaining proper reserves to balance resources and demand and to provide for proper frequency regulation within its operating boundary, to control a BA's impact on the reliability of neighboring BAs across the interchange tie lines and the regional Interconnection generally. Importantly, a BA's failure to comply in real time with these mandatory NERC Reliability Standards could result in system emergencies and reliability failures, such as unscheduled power flows, automatic firm load shedding, or in a worst-case scenario, cascading outages across the Interconnection.

In summary, DEP and DEC, as NERC BAs, are each subject to mandatory NERC Reliability Standards, requiring the Companies to independently balance their respective systems and to provide reliable "firm native load service" to meet customers' electricity needs. NERC's regulations make the Companies responsible for maintaining reliable system operations for customers, and this reality is an underpinning of previous Integrated Resource Plans and the development of the Carbon Plan.

[9] *Id*. For example, Standard BAL-001-2 – Real Power Balancing Control Performance requires that a Balancing Authority reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes.

Q. PLEASE EXPLAIN WHY "RESOURCE ASSURANCE" IS A CRITICAL CONCEPT FOR ENSURING NERC COMPLIANCE AND POWER SUPPLY RELIABILITY IN INTEGRATED RESOURCE PLANNING.

A. "Resource assurance" means proactively taking steps to ensure reliability of electric power resources or other alternatives that would minimize electric power interruptions to maintain reliable Bulk Electric System performance during both normal operations and credible extreme events. Critical to maintaining reliable system operations and compliance with NERC's Reliability Standards is planning for resource adequacy and resource assurance with dependable and dispatchable capacity resources. Based upon my operational experience, a resource plan like the Carbon Plan that is not objectively developed and is unduly biased towards resources for which resource assurance is subject to the sun shining or the wind blowing and does not plan for dependable and dispatchable generation to meet all reasonably-foreseeable contingencies is counter to resource assurance. As I describe in more detail later in my testimony, even coupled with storage, if the sun is not shining for consecutive days due to dense cloud cover or precipitation, this real-world operating condition in the Carolinas could result in little energy production from these resources to store.

Through the Carbon Plan, the Companies will be retiring over 8,000 MW of coal-fired generation representing approximately 20% of existing resource capacity of the combined Companies. Given that the Companies are required to meet NERC Reliability Standards, the Commission should weigh the operational impacts, pace, and sequencing of replacing that significant amount of capacity with a mix of resources that will maintain or improve upon the adequacy and reliability of the grid. This requires an orderly, planned transition that ensures retiring coal units can be replaced with a mix of resources that have similar operational capabilities of the retiring coal units. As CO_2 emissions from the Companies' electric generating resources are reduced through Carbon Plan execution, the collective goal should be to not increase reliability risks for customers and communities.

II. INDUSTRY PERSPECTIVES ON MAINTAINING RELIABILITY WHILE TRANSFORMING THE GRID

Q. MR. HOLEMAN, IN YOUR VIEW, WHAT IS THE IMPORTANCE OF HB 951'S REQUIREMENT TO MAINTAIN OR IMPROVE UPON THE ADEQUACY AND RELIABILITY OF THE EXISTING GRID WHILE ACHIEVING CO_2 EMISSIONS REDUCTIONS TARGETS?

A. As a system operator for DEC and DEP and a Reliability Coordinator within the SERC electric reliability region, I appreciate this provision of HB 951 as it demonstrates that State policy makers understand and appropriately represented the criticality of electric reliability for customers, businesses, and communities when setting policy goals to achieve important and nation-leading CO_2 emissions reduction targets. Duke Energy is committed to prudently plan and purposefully execute CO_2 emissions reductions, as has been the stated corporate-wide goal,[10] while maintaining reliability and affordability.

[10] Duke Energy 2020 Climate Report, *available at* https://www.duke-energy.com/our-company/sustain ability.

HB 951 was enacted in October 2021, just over a year after the 2020 CAISO summer firm load shed event, and only eight months after the February 2021 blackouts in Texas which had dire consequences for customers and communities in ERCOT,[11] and five months after Public Staff petitioned the Commission to open a docket on grid reliability in North Carolina.[12] Reliable electric service is essential to the well-being and vitality of families, businesses, and communities across the Carolinas that DEC and DEP have the obligation to serve. This provision of HB 951 represents a legislative imperative to collectively plan and execute a transition of our electric system resource mix that is prudent and truly balanced across CO_2 emissions reductions targets, costs, and reliability. The following section of my testimony provides the Commission industry perspectives both from NERC and other regions as well as highlights how Duke Energy plans to reliably execute the Carbon Plan to accomplish the energy transition.

(A) <u>NERC is Focused on the Operational and Reliability Risks of Grid Transformation</u>

Q. MR. HOLEMAN, PLEASE EXPLAIN NERC'S CURRENT POSITION ON THE RISKS OF RELIABLY EXECUTING THE TRANSITION TO LOWER CARBON RESOURCES AND THE ASSOCIATED GRID TRANSFORMATION.

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[11] The Texas Department of State Health Services confirmed 246 deaths across 77 Texas counties related to the February 2021 winter storm. Texas Health and Human Servs., Feb. 2021 Winter Storm-Related Deaths–Texas (Dec. 31, 2021), *available at* https://www.dshs.texas.gov/news/updates/SMOC _FebWinterStorm_MortalitySurvReport_12-30-21.pdf.

[12] Docket No. E-100, Sub 173.

A. Due to the necessity of reliable electric service for the public health and safety of customers and for the economy as punctuated by the August 2003 Northeast Blackout, NERC's mandate from FERC is to assure reduction of risks to the reliability and security of the North American Bulk Electric System. In that capacity, NERC has been active in assessing the risks of a transforming electric system spurred by energy policy objectives of the federal government, state governments, utilities, and customers to reduce CO_2 emissions. For example, NERC's 2021 ERO Reliability Risk Priorities Report identifies Bulk Electric System risks that merit the highest attention and mitigation efforts from regulators and grid operators, and specifically highlights transitioning the power system to lower-carbon sources of energy as one of the highest magnitude reliability risks.[13]

The unprecedented shift away from multiple decades of centralized generation to dispersed renewables, batteries, demand response, and other distributed and emerging technologies that rely on a robust communications infrastructure not only poses new challenges for operators and the protocols on which they rely, but has implications for other risk areas identified by NERC that include extreme events, security, and critical infrastructure dependencies. As stated in that report and reiterated in NERC's 2022 State of Reliability Report, recent extreme events such as the 2020 western extreme heat event and

[13] North Am. Elec. Reliability Corp., 2021 ERO Reliability Risk Priorities Report (July 2021), *available at* https://www.nerc.com/comm/RISC/Documents/RISC%20ERO%20Priorities%20Report_Final_ RISC_ Approved_July_8_2021_Board_Submitted_Copy.pdf.

the sustained severe cold weather in February 2021, which caused the largest manual load shed event in North American history of over 23,000 MW, demonstrate how a changing resource mix driven by decarbonizing operating fleets has implications on other risk areas and amplifies those risks.[14] In a system as integrated as the synchronously interconnected Eastern Interconnection electric grid, few if any risks stand in isolation.

Q. WHAT DOES A CHANGING RESOURCE MIX MEAN FOR SYSTEM OPERATORS ON A PRACTICAL LEVEL?

A. The grid transformation risk identified by NERC has a variety of risk components that demonstrate how important it will be to consider real-time system operations that maintain reliability as the Companies transition our resource mix to achieve CO_2 emissions reductions targets through the Carbon Plan. While all the grid transformation risk components identified by NERC are relevant, as I consider the Carbon Plan and its relationship to DEC and DEP real-time grid operations, all technologies have specific design and performance characteristics that contribute to the interconnected Bulk Electric System reliability, just as there are tools in a toolbox. System operations functions have learned by doing over decades using a fairly stable and established set of tools to generate power and to deliver reliable electric service; obviously, the planned energy transition presented in the Carbon Plan is rapidly changing the tools in the System Operator's toolbox that are available to ensure system reliability by

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[14] North Am. Elec. Reliability Corp., 2022 State of Reliability Report (July 2022), *available at* https:// www.nerc.com/pa/RAPA/PA/Performance Analysis DL/NERC_SOR_2022.pdf.

retiring coal units and adding unprecedented variable energy resources to the system over a very short period of time. NERC's 2021 ERO Reliability Risk Priorities Report identified multiple new operational challenges emerging as higher levels of variable generation and inverter-based resources, storage, and distributed energy resources are integrated into the grid, each having different implications for operational forecasting, real-time performance, and operational responsiveness.[15]

Q. DOES NERC RECOGNIZE THAT THE RAPIDLY CHANGING GRID, GENERATION, AND DEMAND-SIDE RESOURCE TOOLS AVAILABLE WILL ALSO REQUIRE CHANGES TO RESOURCE PLANNING TO ENSURE RESOURCE ADEQUACY AND RELIABILITY IS MAINTAINED?

A. Yes. NERC has acknowledged that traditional resource planning methods may not consider the real-world grid impacts and interactions of an evolving resource mix with less baseload generation and more variable generation, inverter-based resources, storage, and distributed energy resources, leading to potential generation or transmission insufficiencies.[16] For example, resource adequacy has traditionally been assumed through verifying capacity with appropriate planning reserves to serve peak demand in long-term resource planning. However, recent industry events have highlighted that the changing resource mix performing in real-world situations can result in energy

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[15] *See* 2021 ERO Reliability Risk Priorities Report.
[16] *Id.*

inadequacy. NERC also identified that fuel disruptions from weather events or extreme natural events may not be fully accounted for in resource adequacy assessments, particularly as more resources with weather-dependent fuel, such as the sun and wind, are integrated in high amounts into the system as grid connected or distributed resources.[17] Another risk component that NERC identified was the sequencing of resource transitions so they do not negatively impact resource adequacy, such as timing coal unit retirements with the full assurance of timely replacement with a mix of resources that have an operational profile complementary to those retiring units.[18] Finally, NERC highlighted the risk component of not having adequate flexible resources that are dispatchable to meet demand when less flexible resources, such as solar and wind, are unavailable.[19]

Q. HAS NERC IDENTIFIED REAL-WORLD EXAMPLES OF THESE CHALLENGES?

A. Yes. NERC's assessment of Bulk Electric System reliability in 2021[20] highlighted unprecedented and practical, real-world examples of grid transformation risks, many of which were also addressed in NERC's 2021 Long-Term Reliability Assessment.[21] In 2021, widespread reductions in solar

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[17] *Id.*
[18] *Id.*
[19] *Id.*
[20] 2022 State of Reliability Report.
[21] North Am. Elec. Reliability Corp., 2021 Long-Term Reliability Assessment (Dec. 2021), *available at* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_ 2021.pdf.

generation occurring in events in both Texas and CAISO due to system disturbances illustrated that continued work is needed to electrically integrate inverter-based resources into the grid. Extreme weather scenarios in 2021, both in summer and winter, set up for extreme operating conditions that stressed what have been historically adequate planning reserve margins, thus exposing a potential incomplete picture for real-time operations when looking at capacity reserve margins in isolation. More coal, nuclear, and natural gas capacity has been replaced by wind and solar in the past ten years, and this trend continues across all regions; just since NERC issued its 2020 Long-Term Reliability Assessment, confirmed coal-fired, nuclear, and natural-gas-fired generation retirements through 2026 have increased by over 126%.[22] When replacing coal-fired and nuclear generation, NERC specifically cautions to plan carefully for adequate system capabilities to maintain NERC Reliability Standards, such as interim, ramping capability, frequency response, and fuel assurance.[23]

Q. DESCRIBE WHAT NERC HAS RECOMMENDED TO REDUCE RELIABILITY RISKS DUE TO A RAPIDLY CHANGING GRID.

A. To reduce these risks, NERC has made specific recommendations to manage and mitigate grid transformation risks and has taken steps to enhance NERC Reliability Standards to address such risks. NERC recommends a variety of approaches, including (1) updating modeling and assessments to consider grid transformation, establishing approaches to evaluate impacts of battery storage,

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[22] *Id*. at 35.
[23] *Id*.

hybrid storage, and DERs on reliability; (2) improving electrical integration of inverter-based technologies into the grid; (3) ensuring sufficient operating flexibility throughout the grid transformation to manage increased variability; and (4) developing protocols that ensure sufficient energy is available for customers even during widespread and long-duration events.[24]

In addition, NERC has begun the process of updating reliability standards in response to recent extreme events and to prepare for grid transformation, such as more robust cold weather event preparation and proactively addressing fuel assurance and energy adequacy issues created as the grid transitions from coal-fired and nuclear generation to relying on wind, solar, hybrid resources and bulk energy storage systems that must be charged, distributed energy resources, and dual-fueled capable gas.[25]

Q. HOW DOES NERC SUGGEST UTILITIES SHOULD MANAGE VARIABILITY IN RESOURCES AND DEMAND DURING THE ENERGY TRANSITION?

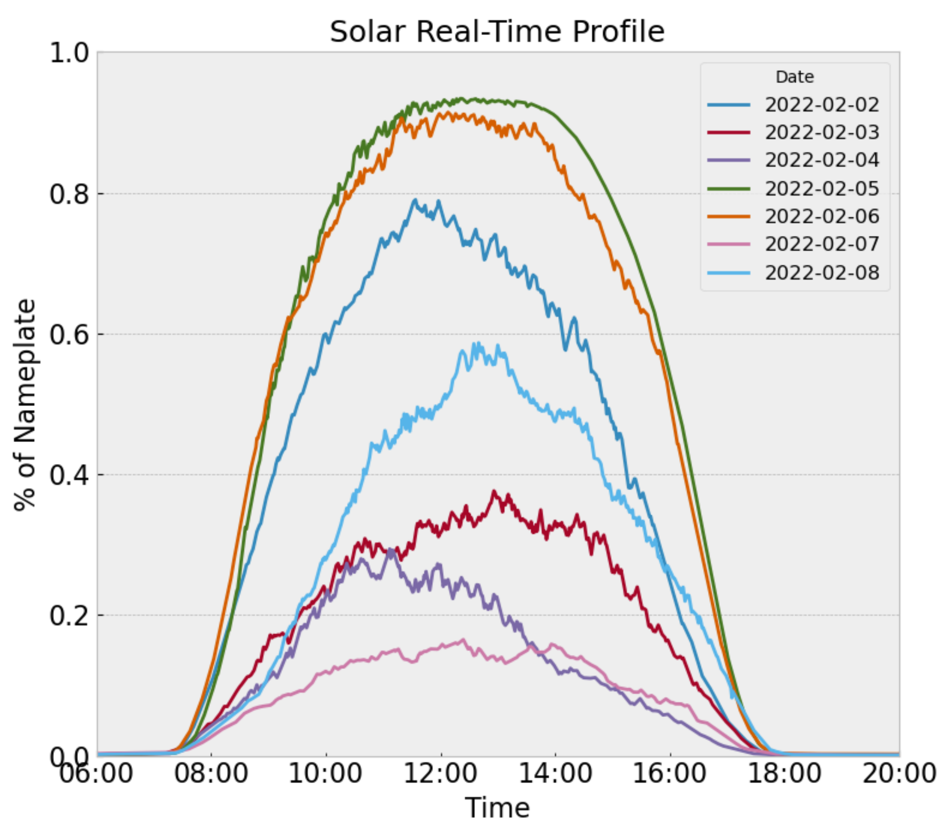
A. Wind and solar do not provide the same operational contributions to the system to deliver capacity at peak demand hours as traditional dispatchable resources like coal, gas, and nuclear. In addition, high penetration of wind and solar have exposed energy shortfalls for both brief and prolonged periods of time due to significant weather-related output fluctuations. This shift in generation resource

[24] 2021 ERO Reliability Risk Priorities Report.

[25] NERC Reliability Standards Under Development, 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination & 2022-03 Energy Assurance with Energy-Constrained Resources, *available at* https://www.nerc.com/pa/Stand/Pages/Standards-Under-Development.aspx.

mix, in combination with growth in demand-side resources and increased electrification, requires that utilities change the way they assess their energy needs, including by considering variability in resources and demand across all hours to maintain resource adequacy, not just long-term capacity needs. Observing Figure 3 below, solar output can vary greatly from day to day. If the operator is counting on energy from these resources to store for peaking capacity, a gap in the resource adequacy of a resource plan may be revealed through energy adequacy issues.

<u>Figure 3: 7-day Solar Profile for February 2-8, 2022</u>



NERC asserts the ongoing need for dispatchable resources to mitigate potential capacity and energy shortfalls due to changing resource mixes by stating that "[u]ntil storage technology is fully developed and deployed at scale, natural-gas-fired generation will remain a necessary balancing resource to provide increasing flexibility needs" [26] and that "[r]esource planning and policy decisions must ensure that sufficient balancing resources are developed and maintained for reliability."[27] To manage the risk of variability, adequate risk margins in the form of flexible operating reserves will be required to meet demand over both shorter operational periods and for prolonged extreme events—ensuring both capacity and energy adequacy.

Q. THE ROLE OF AND NEED FOR NEW NATURAL GAS GENERATION TO REPLACE RETIRING COAL GENERATION AND TO MEET NEW LOAD IS AN IMPORTANT AND CONTROVERSIAL TOPIC RAISED BY MANY STAKEHOLDERS AND INTERVENORS IN THIS DOCKET. DOES NERC HAVE A PERSPECTIVE ON THE ROLE OF NATURAL GAS?

A. NERC strongly acknowledges that flexible gas is the tool that provides operational flexibility and energy sufficiency as the Companies transform the grid. As NERC President and CEO James Robb explained to the United States Senate Committee on Energy and Natural Resources in March 2021:

> Natural Gas is essential to a reliable transition. . . . [O]n a daily basis in areas with significant solar generation, the mismatch between the solar generation peak and the electric load peak necessitates a very flexible generation resource to fill the gap. Natural gas is best positioned to play that role. The criticality of natural gas as the 'fuel that keeps the lights on' will remain unless or until very large-scale battery

[26] 2022 State of Reliability Report at 26.
[27] *Id*. at. 27.

deployments are feasible or an alternative flexible fuel such as hydrogen can be developed.[28]

Q. PLEASE DISCUSS HOW NERC'S RECENT FOCUS ON RELIABILITY AND RESOURCE ADEQUACY ASSOCIATED WITH INTEGRATING VARIABLE ENERGY RESOURCES INFORMS THE COMPANIES' DEVELOPMENT OF THE CARBON PLAN AND THE IMPORTANT ROLE OF THE COMISSION IN APPROVING AN EXECUTABLE AND RELIABLE PLAN.

A. Recognizing HB 951's provision to maintain or improve upon the adequacy and reliability of the grid, the importance of NERC guidance to carefully plan for system reliability requirements when retiring resources, maintaining ongoing operational flexibility to operate the grid, and ensuring sufficient energy for customers in all conditions and over all time periods cannot be understated. Duke Energy's Carbon Plan—both through the reliability validation step of the modeling process as well as through further assessments and analysis discussed in Appendix Q (Reliability and Operational Resilience Considerations)—is laser-focused on reliability.

Through recent events and operational experience, the Companies have seen grid transformation risks span all regions of the country, agnostic of industry structure. Seasonal reliability evaluations from NERC in recent years

[28] James R. Robb, North Am. Elec. Reliability Corp., Testimony Before United States Senate Committee on Energy and Natural Resources, Full Committee Hearing On The Reliability, Resiliency, And Affordability of Electric Service, at 9, 10 (Mar. 11, 2021), *available at* https://www.energy.senate.gov/services/files/EB1D7E02-4DFF-A6A9-002341DA34CF.

have not identified significant reliability risks for the Southeast region,[29] and the Companies must strive to reduce risks, not heighten risks, for their customers and communities as their resource mix transitions through the Carbon Plan to achieve vital CO_2 emissions reductions targets. The HB 951 provision to maintain or improve reliability while reducing CO_2 emissions provides a solid foundation to ensure the Companies can evaluate the energy transition risks, and from those risks establish appropriate planning and operating margins, learn and contribute to industry experience as the resource mix evolves, and apply those learnings to the benefit of DEC and DEP customers.

Q. PLEASE EXPLAIN SERC'S CURRENT POSITION ON THE RISKS OF RELIABLY EXECUTING THE TRANSITION TO LOWER CARBON RESOURCES AND THE ASSOCIATED GRID TRANSFORMATION.

A. SERC's 2021 Regional Risk Report, which considers past regional risk reports and NERC risk areas, identified several themes that are directly relevant to the region's current low carbon energy transition and that will be accelerated through the Carbon Plan execution.[30] New system planning and operations risks

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[29] NERC seasonal reliability assessments evaluate the generation resource and transmission system adequacy necessary to meet projected summer or winter peak demands and operating reserves, respectively and identifies potential reliability issues. NERC Winter and Summer Reliability Assessment reports have shown the Southeast region as not having heightened reliability concerns over the past several years. North Am. Elec. Reliability Corp. Reliability Assessments https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx (last visited Aug. 18, 2022).

[30] SERC, 2021 SERC Regional Risk Report (December 2021), *available at* https://www.serc1.org/docs/ default-source/committee/ec-reliability-risk-working-group/2021_serc_regional_risk_report.pdf?sfvrsn =b6de2959_10.

are introduced as traditional centralized generation retires, the system relies more on gas, and simultaneously renewable generation increases. This is a theme for NERC and across other regions of the country, and SERC is no different. The Carbon Plan portfolios illustrate retiring over 6,000 MW of coal-fired generation and introducing anywhere from 11,000 to 18,000 MW of combined solar, wind, and batteries in addition to more demand-side and distributed energy resources by 2035.[31]

SERC identifies that traditional long-term planning, short-term planning and real-time operations must respond to the challenges presented by such significant shifts in resource mix and recommends identifying and taking proactive actions to make necessary changes and disseminating of best practices within SERC and across regions. New models and tools will be needed to integrate increasing and substantial levels of variable energy resources, such as inverter-based resources, batteries, and distributed energy resources, into the grid. Variable energy resources change operational forecasting, voltage regulation, dynamic and transient performance response, are weather-dependent, and create sudden change in dispatch patterns. In addition, the report states, "[s]ince VERs are weather dependent, planning for backup resources in the absence of generation becomes essential to maintain the reliability of the system[,]"[32] highlighting the resource and energy adequacy considerations critical to assessing a carbon-reducing portfolio. SERC members are focusing

[31] Carbon Plan Executive Summary at 14, Figure 7.
[32] *Id.*; SERC Regional Risk Report at 14.

efforts on interconnection requirements for inverter-based resources and efficiently sharing and leveraging operational experience within SERC and across regions. The transformation of the grid creates evolving operational complexity and challenges, including how to incorporate new emerging technologies into a secure and reliable Bulk Electric System.

Q. BRIEFLY DESCRIBE HOW GRID TRANSFORMATION COMPOUNDS OPERATIONAL RISK.

A. As an integrated electrical system, no issue or risk stands in isolation, particularly as overall system complexity increases. The purpose of NERC Reliability Standards in addressing risks, if followed, is to provide a fundamental level of assurance of the continued reliability of the interconnected Bulk Electric System. The Carbon Plan introduces an unprecedented shift in resource mix over the next decade that may serve to amplify other Bulk Electric System risks that are not as directly related to a changing mix, as NERC emphasized. For example, consider the increased number of digital assets distributed across the system in the future and how that may impact cybersecurity or extreme weather events if communication systems are impacted. Also, the Companies must prepare for unanticipated operational interactions amongst new and changing amounts of resources in the context of an interconnected electric system and natural forces over which they have no control. The loss of solar and wind output events due to system disturbances—

in Texas with over 1,000 MW in solar reduction,[33] the multiple events in CAISO each with hundreds of MWs in solar reductions,[34] and loss of wind events in Texas[35]—are real-world examples that grid transformation at scale will include evolving challenges and operational experience. Finally, the fact that all other regions are effectively experiencing a similar shift in resource mix creates in some cases common modes of risk or compounding risk with related generation and transmission dependencies across regional interties. SERC is a component of the Eastern Interconnection, so the Companies are vigilant of the system planning and operations reliability responsibilities shared with neighboring systems.

(B) <u>Approaches to Maintaining Grid Reliability in Other Regions</u>

Q. MR. HOLEMAN, DO DEC AND DEP CONSIDER THE APPROACHES OF OTHER REGIONS WHEN PLANNING THEIR SYSTEMS?

A. Yes. Duke Energy has a culture of learning from events, inside and beyond its operating region, and proactively making improvements to mitigate current and future risks. The department I lead within Duke Energy is in a unique position

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[33] North Am. Elec. Reliability Corp, Odessa Disturbance Report (September 2021), *available at* https://www.nerc.com/pa/rrm/ea/Documents/Odessa_Disturbance_Report.pdf.

[34] Four separate solar PV and DER loss events occurred from June to August 2021. *See* North Am. Elec. Reliability Corp, Multiple Solar PV Disturbances in CAISO (April 2022), *available at* https://www.nerc.com/pa/rrm/ea/Documents/NERC_2021_California_Solar_PV_Disturbances_Report.pdf.

[35] North Am. Elec. Reliability Corp, Panhandle Wind Disturbance Report (August 2022), *available at* https://www.nerc.com/pa/rrm/ea/Documents/Panhandle_Wind_Disturbance_Report.pdf.

of having a broad view of industry learnings and operational experience by operating in six states, two RTOs, three vertically integrated utilities, and two NERC reliability regions. Duke Energy's System Planning and Operations personnel and related support organizations are direct participants in numerous working groups and committees directly addressing system planning and reliability activities with NERC, Regional Reliability Organization of SERC and Reliability First, MISO and PJM—advancing critical risks analysis, solution development, and mitigation. In addition to learning through its operations network, Duke Energy participates in industry forums such as the North American Transmission Forum and EPRI, has a robust set of internal Operational Excellence processes focusing on continuous improvement, and engages in focused efforts through North Carolina and South Carolina regulatory proceedings such as those after the 2014 polar vortex[36] and more recently after events related to 2021 Winter Storm Uri.[37] Strong DEC and DEP operational performance in 2015 and 2018 cold weather events demonstrated the payoff of activities undertaken by the Companies to apply lessons learned from the 2014 polar vortex. The Companies will apply this same rigor as they undertake the Carbon Plan grid transformation, through their analysis of events and operational experience to continuously build risk mitigations for their customers and communities.

[36] Docket Nos. M-100, Sub 163 & E-100, Sub 173.
[37] Docket No. E-100, Sub 173, P.S.C.S.C. Docket No. 2021-66-A.

Q. PLEASE DESCRIBE WHAT DEC AND DEP SYSTEM OPERATIONS ARE LEARNING FROM STUDIES IN OTHER REGIONS REGARDING GENERATION FLEET TRANSITION TO LOW CARBON RESOURCES.

A. While there are many detailed technical, engineering, and operator-based learnings, from where I sit leading the System Planning and Operations function across six states, broader learnings from the changing resource mix and grid transformation to lower carbon resource falls into three categories: (1) the consistency across the United States of grid transformation challenges facing system planning and operating functions, (2) the increasing complexity and practical challenges the grid transformation is imposing on real-time operations in managing essential reliability services, energy adequacy, ramping, and variability, and (3) the impacts of pace and sequence of grid transformation on Bulk Electric System reliability.

As NERC pointed out, much of the country is either retiring or planning to retire baseload coal-fired, natural-gas-fired, and nuclear generation, due to state policy, utility goals, consumer preferences, and in the case of nuclear largely due to wholesale market drivers, with confirmed coal retirements across regions reaching 60,000 MW by 2031.[38] As summarized in Figure 4, other regional NERC system operations functions are studying the impacts to the grid with less centralized coal-fired, nuclear, and natural-gas-fired resources and higher penetrations of variable energy resources such as solar, wind, and

[38] 2021 Long-Term Reliability Assessment at 35.

batteries, as public policy is shaping resource selections and demand-side options to deliver CO_2 emissions reductions.[39] While certain findings are specific to regional grid operations, the Companies noted the strong consistency of reliability themes identified by peer NERC system operations functions in recognizing the potential of reduced reliability margins, capacity and energy shortfalls, the need for balancing resources that have similar operational profiles to flexible gas and do not rely on charging, changing grid dynamics as traditional generation retires and is replaced by variable generation, and increasing complexity caused by renewable and battery storage penetration as electric systems eliminate CO_2 emissions. These themes are all relevant when considering maintaining or improving upon reliability as the Companies' resource mix changes through the Carbon Plan.

Figure 4: Regional Fleet Decarbonization Studies Operational Challenges

Summary of Operational Challenges Identified in Scenario-Based Regional Studies on Fleet Decarbonization

Study	Scenario Scope	Common Challenges in System Decarbonization
MISO Renewable Integration Impact Assessment (2021)[40]	Multiple scenarios with increasing levels of renewable penetration	✓ **More complexity in planning and operations**
Energy Transition in **PJM** (2022 & ongoing) [41]	Multiple scenarios with increasing annual energy served by renewables	

[39] The following North American electric operating entities published studies or reports on the implications of high renewable penetration and/or a decarbonized grid, noting that this does not represent an exhaustive list of all such studies: MISO, New England Independent System Operation (NE-ISO), New York Independent System Operator (NYISO), PJM, and Western Electricity Coordinating Council (WECC).
[40] MISO, MISO's Renewable Integration Impact Assessment (RIIA) (February 2021), *available at* https://cdn.misoenergy.org/RIIA Summary Report520051.pdf.
[41] PJM, Energy Transition in PJM: Frameworks for Analysis (December 2021) *available at* https://pjm.com/-/media/committees-groups/committees/mrc/2021/20211215/20211215-item-09-energ y-transition-in-pjm-whitepaper.ashx.

NYISO Reliability and Market Considerations For A Grid In Transition (2019) [42]	Transition to 70% renewables by 2030	✓ **Energy adequacy challenges occur** ✓ **Adequate capacity challenged in seasonal and extreme events** ✓ **Additional operational flexibility needed for balancing** ✓ **Dispatchable gas generation or resources with the same operational properties needed** ✓ **Careful planning required using batteries for reserves – particularly in prolonged events** ✓ **More system forecasting uncertainty with renewables, demand-side resources, distributed energy resources, and batteries**
WECC 2040 Clean Energy Sensitivities Study (2022) [43]	Multiple scenarios with high levels of clean energy	
ISO-NE Future Grid Reliability Study Phase 1 (2022) [44]	Multiple specific scenarios of increasingly higher levels of system decarbonization	

Q. ARE THERE IMPLICATIONS IF GENERATION FLEETS ACROSS ALL REGIONS ARE SIMULTANEOUSLY DECARBONIZING?

A. Yes. Every region will be seeking to optimize variable energy resources, storage, and flexible gas resources to the benefit of that region's CO_2 emissions

[42] New York Independent System Operator (NYISO), Reliability and Market Considerations For A Grid In Transition (December 2019), *available at* https://www.nyiso.com/documents/20142/2224547/ Reliability-and-Market-Considerations-for-a-Grid-in-Transition-20191220%20Final.pdf.

[43] Western Electricity Coordinating Council (WECC), 2040 Clean Energy Sensitivities Study (January 2022), *available at* https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Administrative /2040%20Clean%20Energy%20Sensitivities%20Report.pdf&action=default&Default ItemOpen=1.

[44] ISO New England (ISO-NE), 2021 Economic Study: Future Grid Reliability Study Phase 1 (July 2022), *available at* https://www.iso-ne.com/static-assets/documents/2022/07/2021_economic_study_ future_grid_reliability_study_phase_1_report.pdf.

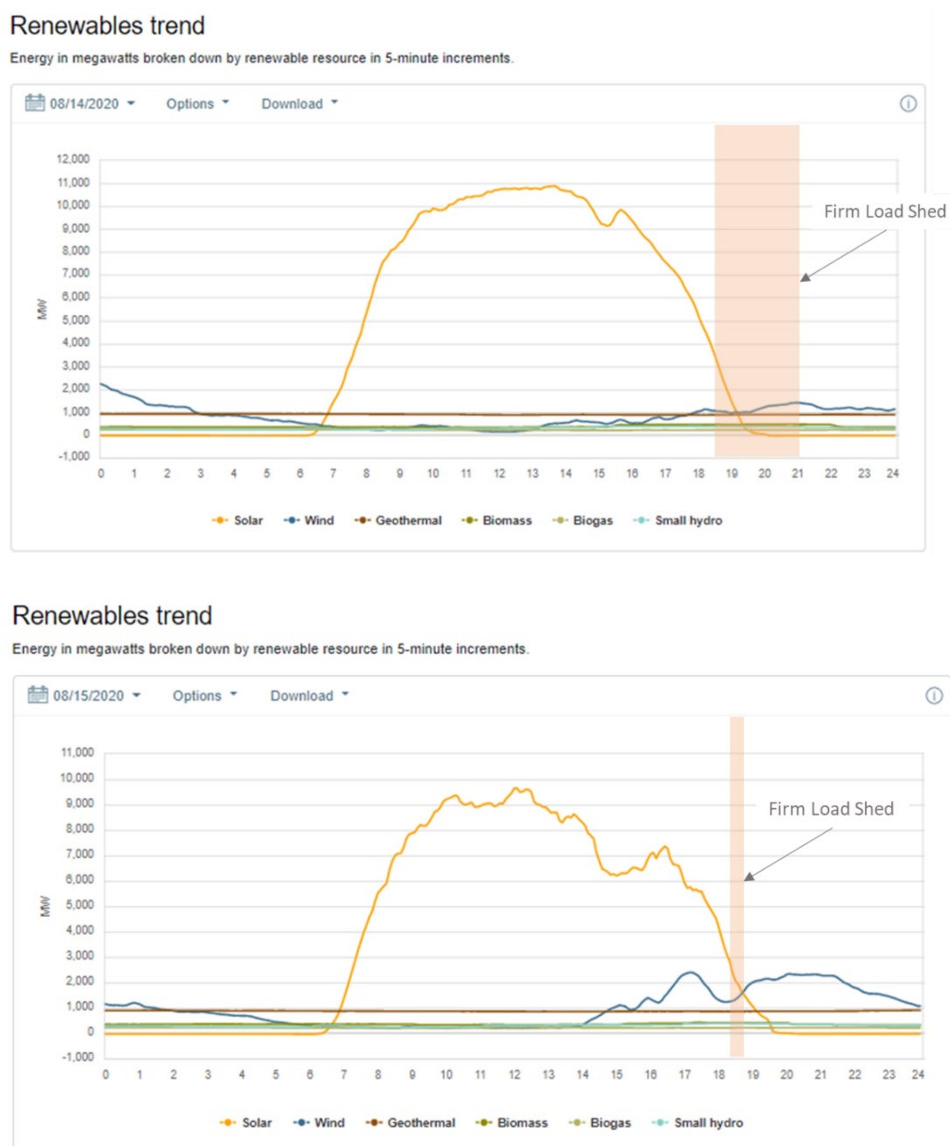
reductions targets and to maintain reliability while retiring mainly coal and nuclear units. This creates a common mode effect across regions with the potential of fewer flexible resources available on a firm or non-firm basis to leverage across regions, particularly when broad regional events, such as polar vortices that typically span north to south across the midwest and/or eastern portion of the United States, stress adjacent systems. Equally important, this shared experience creates opportunities for continued industry collaboration, exchanging operational experience, and developing solutions to reduce commonly identified grid transformation risks for customers and communities.

Q. PLEASE DESCRIBE WHAT DEC AND DEP SYSTEM OPERATIONS ARE LEARNING FROM RECENT OPERATIONAL EVENTS AS GENERATION FLEETS TRANSITION TO GREATER RELIANCE UPON LOW CARBON RESOURCES.

A. Recent events in Texas and California illustrate in real-world terms the increasing complexity a changing resource mix imposes on system planning and operations functions, and the evolutionary nature of operating experience as the United States moves deeper into electric system decarbonization. The 2020 California firm load shed event during the western heat wave was deemed to have no single root cause, but rather demonstrated the layering effect of multiple factors including weather-induced demand spikes exceeding resource adequacy and planning targets, insufficient resources to balance demand and supply due to a clean energy policy transition, and market functions that compounded the existing supply challenges.[45] The CAISO System Operators were working with a higher renewable resource mix driven by aggressive state decarbonization policies. As the system approached "net demand peak," which is the peak of demand net of solar and wind generation, significant levels of solar generation declined in the late afternoon at a faster rate than demand for air conditioning and other load sustained during the heat wave—and load shed ensued. Further, the heat wave was widespread across the region, and market functions masked the fact that physical supply in the market was scarce, allowing more low-priority imports to clear than could actually be delivered. As pointed out by NERC, risks amplify other risks, and in this case resource adequacy issues converged with system operations reliability and market protocols. System Operators were managing an increasingly complex system with more dependent variables in extreme system conditions, and with a set of system resources that look different than recent prior years.

[45] California Independent System Operator (CAISO), Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave (January, 2021), *available at* http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf#search=root%20cause%20report.

Figure 5: August 14-15, 2020 CAISO Firm Load Shed Events[46]



Winter Storm Uri in 2021 spanned much of SPP, MISO, and ERCOT regions, impacting 26 states with snow and frigid temperatures for multiple days. Like the California heatwave but on broader scale, this event highlighted the increasing complexities and dependencies of electric systems in transition

[46] Sourced from CAISO real-time displays on August 14, 2020 and August 15, 2020. Figure 5 is also replicated in Reliability Panel Exhibit 1.

and the need to plan for extended seasonal events. The joint report issued by FERC and NERC identified the many factors contributing to this event;[47] however, from the perspective of system operations and a transforming grid, what this event fundamentally illustrates is the interaction of policy, existing known risks, and how risks can amplify in extreme and prolonged events. At the time of the event, weatherization of fuel supply was not required by policy and weatherization of assets was not incented through market mechanisms nor addressed by policy, perpetuating known existing equipment risks of all generation types, both traditional and renewable. As an aside, the Companies have had equipment inspection and weatherization practices in place for key assets, and those practices were further improved after the 2014 polar vortex. Further, Winter Storm Uri impacted much of the United States and was prolonged over several days, requiring adequate resources to contribute to increased system needs for an extended period of time.

As the Companies consider system resource mix changes through decarbonization, electric systems become more complex, layered, and interdependent when meeting a variety of operational conditions. In context of a storm like Uri, a resource mix that relies on significant levels of solar capacity may have little generation for days due to precipitation and cloud cover. A system that relies on energy efficiency and demand response to reduce demand may lose margin as customers need more energy in severe winter conditions. A

[47] FERC, February 2021 Freeze Underscores Winterization Recommendations (November 2021), *available at* https://www.ferc.gov/news-events/news/final-report-february-2021-freeze-underscores-winterization-recommendations.

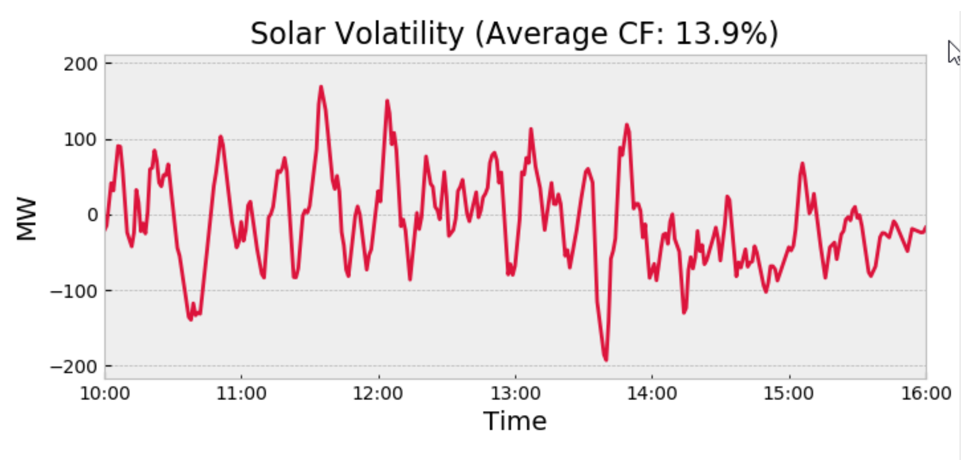
system that relies heavily on batteries would need to carefully plan and coordinate energy balance and replenishment of energy-limited batteries to span a multi-day event, particularly if those batteries are charged from solar. These events highlight how the Companies must evaluate future resource mixes in the context of extreme seasonal events, including understanding both man-made and natural fuel dependencies, operating parameters of all resources, availability of demand response and distributed resources, reliance on storage, and how all the various resources in a new resource mix may be impacted during similar prolonged extreme operating conditions and time periods.

A changing resource mix moving to high penetrations of variable energy resources is evolving operating experience. As discussed earlier, the loss of significant amounts of solar generation, such as in Texas over 1,000 MW of solar reduction and in CAISO multiple events with hundreds of megawatts in solar reductions in each event, illustrates how significant real-time fluctuations in inverter-based resources can occur.

Q. HOW DO THESE RECENT OPERATIONAL EVENTS IN OTHER REGIONS INFORM THE COMPANIES' PLANNING TO EXECUTE THE CARBON PLAN?

A. The Carbon Plan portfolios show roughly 7,000 to 12,000 MW of new solar by 2035 – observing Figure 6 below, consider that volatility increasing to a 1,000 MW or more peak-to-trough change in solar output as a percentage of operating reserves, and how planning for and responding to that in real-time systems complicates the system. This summer, Texas has experienced depressed contribution levels of wind resources over several days during the July heat dome weather pattern just as energy consumption reached unpreceded levels in ERCOT.[48] Through much of the second half of 2021, Europe experienced a broad weather pattern shift reducing wind generation outputs and average capacity factors for much of the second half of 2021.[49] The key point here is that weather patterns can cause temporal or seasonal anomalies of sun and wind forecasts. As operating experience grows with significant amounts of inverter-based resources, wind and sun fueling significant megawatts of capacity and energy, and batteries operating at significant scale, system planning and operations functions will need to prepare for more complex interactions and potential disruptive events.

<u>Figure 6: Solar Volatility – December 4, 2021</u>



[48] See ERCOT published news from July 10, 2022 and July 13, 2022 appealing to Texans and businesses to conserve energy and describing lower than normal wind contribution, available at: https://www.ercot.com/.

[49] See evaluation of low winds and impacts on power generation output in 2021 by European Commission Copernicus Climate Change Service, available at https://climate.copernicus.eu/esotc/2021/low-winds (last visited August 3, 2022).

(C) Applying Lessons Learned to Maintain DEC and DEP Reliability During Grid Transformation

Q. MR. HOLEMAN, DESCRIBE HOW THE PACE OF GRID TRANFORMATION CAN IMPACT RELIABILITY.

A. Pace and sequencing of capacity resource retirements are critical elements of grid transformation that can have reliability consequences if replacement capacity resource mixes are not replaced in a timely fashion nor have similar operational capabilities as those replaced. NYISO noted in their 2022 Power Trends report the reality of eroding reliability margins as fossil-fueled resources retirements are outpacing clean-energy resources coming online, and the potential need to increase planning margins to accommodate growing renewable penetration on their system.[50] NERC noted MISO's increasing risk of energy deficiencies and unserved energy as 35,000 MW of coal-fired generation retires by 2040 and is replaced largely with solar and wind in their queue.[51,52] Recently, based on capacity auction outcomes and shortfalls in the Loss of Load Expectation ("LOLE") and reserve margin targets, resource adequacy due to energy transition has been a focus of MISO leadership discussions.[53] MISO said its preliminary 2022 regional resource assessment

[50] New York Independent System Operator, Power Trends 2022: The Path to a Reliable, Greener Grid for New York (2022), *available at* https://www.nyiso.com/documents/20142/2223020/2022-Power-Trends-Report.pdf.

[51] MISO Regional Resource Assessment at 14 (November 2021), *available at* https://cdn.misoenergy.org/2021%20Regional%20Resource%20Assessment%20Report606397.pdf.

[52] 2021 Long-Term Reliability Assessment at 21.

[53] RTO Insider, *MISO Describes Bleak RA Future, Stakeholders Push Back* (June 20, 2022), *available at* https://www.rtoinsider.com/articles/30325-miso-bleak-ra-future-

showed retirement of controllable resources and mostly renewable additions is further eroding capacity—and more generation is retiring than coming online over the next five years, creating further risk.[54] Recently coal retirements have been delayed in specific MISO states in order to buttress reserves as MISO grapples with this challenge.[55]

California is implementing some of the most aggressively-paced decarbonization polices in the country. Approximately one year prior to the mid-August 2020 firm load shed event, CAISO filed comments with the California Public Utilities Commission ("CPUC") forewarning of near-term reliability needs and the potential summer capacity deficiencies in 2021 when loads remain high but solar production decreases, urging the CPUC develop a plan to prioritize more procurement resources additions to come online, along with extending water regulations for gas-fired resources necessary to maintain reliability.[56] California also recently passed legislative measures that delay the closure of natural gas plants and expedite energy generation projects in an effort

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stakeholders-push-back#:~:text=
INDIANAPOLIS%2C%20Ind.,pushed%20back%20on%20the%20narrative.

[54] *Id*

[55] Utility Dive, *Alliant, We Energies walk back Wisconsin coal retirement plans in light of MISO's expected capacity shortfalls* (June 24, 2022), *available at* https://www.utilitydive.com/news/wisconsin-utilities-coal-retirement-miso-delay/626005/; E&E News, *Why the Midwest worries about future blackouts* (August 8, 2022), *available at* https://www.eenews.net/articles/why-the-midwest-worries-about-future-blackouts/#:~:text=Worries%20about%20outages%20go%20beyond,outages%20in%20 the%20months%20ahead.

[56] Comments of the California Independent System Operator Corporation, Rulemaking 16-02-007 (P.U.C. Cal. Jul. 22, 2019), *available at* https://www.caiso.com/Documents/Jul22-2019-Comments-PotentialReliabilityIssues-R16-02-007.pdf.

to avoid potential capacity shortfalls over the next five summers.[57] California's political leaders were publicly discussing delaying the retirement of Diablo Canyon nuclear site by 2025 to support interim system adequacy and reliability needs.[58]

Q. WHAT IS THE KEY TAKEAWAY FROM YOUR DISCUSSION OF THE RELIABILITY CHALLENGES BEING EXPERIENCED IN OTHER REGIONS AND HOW SHOULD THEY INFORM THE COMMISSION'S CONSIDERATION OF THE CARBON PLAN?

A. HB 951 mandates a significant resource transition of the Companies' generating fleets and system operations functions over the next ten years but also explicitly provides this Commission discretion on CO_2 emission target timing based on the need to maintain existing grid reliability, which is a critically important planning consideration for the Commission, the Companies, and their customers and communities.

While the foregoing national perspective may seem like an overload of information regarding other regions, understanding the analyses and experiences of others in the industry is exactly how system operations functions will navigate a transforming grid. There will always be specific regional differences in geography, weather, generation sources, grid structure, consumer drivers, and regulations; however, it is instructive to understand that there is

[57] California Assembly Bill 205 approved by Governor Gavin Newsome on June 30, 2021.

[58] E&E News, *Calif.'s last nuclear plant faces closure. Can it survive?* (July 19, 2022), *available at* https://www.eenews.net/articles/calif-s-last-nuclear-plant-faces-closure-can-it-survive/.

broad industry consensus at NERC and across the country on the key system operations themes and challenges that will be essential to a reliable transition to carbon neutrality in the coming decades. The Companies' System Operators, like those in other regions, must adjust to decisions made by policy makers and provide timely feedback on how those policies unfold through long-term planning and ultimately into real-time system operations. Therefore, maintaining robust, ongoing reliability analysis and discussions on behalf of customers and communities will be a critical success factor as the Carbon Plan execution is launched and subsequently updated every two years.

Q. IN YOUR VIEW, BASED ON NERC RISK FOCUS AREAS AND OPERATIONAL LEARNINGS FROM INDUSTRY, WHAT PRIORITIES WILL DEC AND DEP SYSTEM OPERATIONS CONSIDER TO ENSURE SYSTEM RELIABILITY FOR THE CARBON PLAN GENERATION FLEET TRANSITION?

A. As I discussed previously, the industry is on this journey together, and the Companies must learn along the way and be prepared to stop, evaluate, and adjust as events and operational learnings unfold to reduce risks and assure customers that their system is adequate to meet their energy needs at all times of night and day, in all weather conditions. DEC and DEP system operations' priorities track with NERC's identified risk components and related mitigations, across all system planning and operating functions, including but not limited to engineering and technical analyses, business processes, tools and systems, operational forecasting and planning, control room protocols and procedures, and operator training and qualifications. However, when I step back and think broadly about this critical initial step of the Carbon Plan and what to prioritize, first is maintaining robust resource diversity to have as many tools available in DEC and DEP System Operators' toolbox to manage and respond to system dynamics and a variety of operating conditions, and second is proactively and continuously managing risk margins as the Companies' resource mix evolves in order to forecast and respond to both capacity and energy needs for our customers and communities across all operating time horizons, weather and operating weather conditions.

Resource diversity is necessary, and DEC and DEP System Operators must have all types of tools in their Bulk Electric System resource toolbox that maintain or improve reliability of the grid as the Carbon Plan CO_2 emissions reductions move forward. Most important is understanding and planning for the specific operational contribution each resource has towards capacity and energy adequacy and reliability, just as they contribute to CO_2 emissions reductions. As noted in the Modeling and Near-Term Actions Panel, the Carbon Plan portfolios offered by the Companies for the Commission's consideration include a diverse and robust set of resources that are phased-in as coal units retire, prudently advancing energy transition and carbon reductions.

Further, NERC reliability requirements mandate that certain amount of reserves are online and ready to respond immediately to balancing needs, while others are ready to start and respond within minutes. With the significant and unprecedented amounts of variable generation proposed for energy transition and included in the Carbon Plan, it cannot be underestimated how critical it will be to respond at scale across both short and prolonged time horizons with flexible, dispatchable resources to maintain reliability. The Companies will need *all* types of resources to manage what is already known, such as outages, fuel dependencies, polar vortices, heat waves, and hurricanes; however, more significantly, resource diversity creates defense-in-depth and flexibility to respond to unanticipated events at any time or season, man-made or due to natural forces.

Q. PLEASE DESCRIBE HOW DEC AND DEP SYSTEM OPERATIONS CONSIDER APPROPRIATE OPERATIONAL MARGIN IN MANAGING RELIABILITY AS GENERATION FLEETS TRANSITION TO GREATER RELIANCE UPON LOW CARBON RESOURCES.

A. The function of system operations is a second-by-second balancing act, operating the system to balance demand and supply, frequency and voltage limits, resources available and resources in outage, forecasted load versus actual load, allowance of maintenance windows, weather, neighboring system status, unanticipated events, among others. System operations functions over recent decades have experienced relatively known and stable parameters with a mix of traditional centralized generation. The changing resource mix to achieve CO_2 emissions reductions and the related grid transformation is a significantly more complex balancing act with exponentially more variables for system planning and operations functions to forecast and manage. Moreover, the pace, timing, and sequencing of how resources will retire and come into service through the execution of the Carbon Plan is unprecedented and adds yet another layer of complexity.

System operations functions manage risk through ensuring margin in operations in order to meet NERC Reliability Standards and most critically making sure the Companies provide reliable electric service to their customers and communities. The Companies' priority will be to proactively evaluate risks introduced through the Carbon Plan resource transitions and ensure appropriate operational reserve margins and operational flexibility in their systems to meet NERC Reliability Standards and mange risks to providing reliable electric service. Ensuring margin in operations can take on many forms, such as modifying planning, operating and contingency reserve requirements, creating operating flexibility across varying circumstances of fuel availability and operating conditions, updating forecasting and operating protocols.

As discussed previously, the industry has recognized this need for additional margin with flexible, dispatchable resources in regional system fleet decarbonization studies and through operational events and is already in the process of updating NERC Reliability Standards to address this needed margin. Like NERC leadership, I view having firm, flexible, dispatchable gas resources essential for the Carolinas to anchor much of this needed margin at scale throughout this grid transformation, both for energy adequacy in short-term time horizons and to provide Bulk Electric System resiliency and adequacy in extended seasonal and extreme events. NERC specifically points out the need to ensure adequate flexible resources for extreme weather, stating that "[a] comprehensive resource planning construct must focus attention on energy available with the understanding that capacity alone does not provide for reliability unless the fuel behind it is assured in extreme weather."[59]

Q. BRIEFLY DESCRIBE IN SUMMARY HOW DEC AND DEP SYSTEM OPERATIONS APPROACH THE ANTICAPATED IMPACTS OF A CHANGING RESOURCE MIX THROUGH CARBON PLAN EXECUTION.

A. For the DEC and DEP systems, System Planning and Operations will be evaluating the anticipated consequences of a changing resource mix through an approved Carbon Plan and striving to optimize different resource contributions, or tools in the toolbox, as part of a reliable integrated system. In addition, the Companies must remain equally aware and prepare for the potential unintended consequences of electric system interactions of that new mix. The Companies' system planning and operations functions will also be evaluating such details as how combining balancing authorities impacts system flows in real time, how the deployments of customer programs and more distributed energy resources impact system planning and operational forecasting calculations, how the pace and timing of coal unit retirements and a spectrum of new resources coming online impact system stability, how to optimize various types of storage on the system in real time and for managing reserves, and how using resources differently such as significant cycling of gas units and batteries to meet

[59] 2022 State of Reliability Report at 27.

renewable fluctuations changes equipment lifecycle, maintenance, and outage patterns. The Companies will continue learning from their Duke Energy colleagues operating in other regions and from NERC industry peers to be ready to respond to both planned and unintended consequences that will emerge from an integrated electric system with a new resource mix that achieve CO_2 emissions reductions targets, yet has significantly more variables to plan and operate.

III. DUKE ENERGY'S APPROACH TO ENSURING RELIABILITY IN THE CARBON PLAN

Q. MR. ROBERTS, DESCRIBE FROM THE SYSTEM OPERATIONS PERSPECTIVE HOW THE COMPANIES APPROACH RELIABILITY IN THE CARBON PLAN.

A. As witness Holeman discussed earlier, a core objective of the Carbon Plan is to meet HB 951's requirement that "any generation and resource changes ***maintain or improve upon*** the adequacy and reliability of the existing grid."[60] This mandate recognizes the Companies' public service obligation to plan and operate their generating fleets and transmission and distribution systems to provide reliable electric service to customers at all hours of the day, every day of the year, in all weather and grid conditions.

Each of the Carbon Plan portfolios will require major changes in generation resources and, for reasons explained above, create new challenges to ensuring the adequacy and reliability of the systems. To ensure the continued

[60] N.C. Gen. Stat. § 62-110.9(3) (emphasis added).

reliability of the DEC and DEP systems under each of the Carbon Plan portfolios, the Companies evaluated reliability risks and mitigating solutions in the following areas: (1) resource and energy adequacy from renewables and storage; (2) additional firm gas generation and transportation; (3) coal generator reliability during the transition; (4) the need for zero-emitting load following resources ("ZELFRs") to reach net-zero; (5) flexible generation needs for integrating renewables; and (6) future system resilience to withstand extreme weather events. Appendix Q (Reliability and Operational Resilience Considerations) to the Carbon Plan discusses each of these areas in detail.

Q. DESCRIBE THE SIX RELIABILITY RISKS AND THE MITIGATING SOLUTIONS ADDRESSED IN APPENDIX Q.

A. 1) With increased levels of renewable generation in the Carbon Plan portfolios, capacity adequacy remains relevant; however, a new risk of energy adequacy is introduced. NERC has a Task Force reviewing this risk and is proposing a Reliability Standard as mitigation.[61] In the Carolinas, weather patterns leading up to peak events may not allow renewables to generate (and storage to allocate) energy to meet demand in all hours. During an extreme cold weather period, low solar capacity factors—even with the significant nameplate solar additions identified in the Carbon Plan—could lead to insufficient energy for serving load if not supplemented with alternative dispatchable, high capacity factor, fuel secure resources.

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[61] North Am. Elec. Reliability Corp., Energy Reliability Assessment Task Force, https://www.nerc. com/comm/RSTC/Pages/ERATF.aspx (last visited Aug. 18, 2022).

2) As recognized by NERC,[62] gas generation resources (combustion turbines ("CT"), combined cycle units ("CC") and dual fuel conversions) are a necessary reliability "bridge" to achieving carbon neutrality to fill part of the resource adequacy needs created by the retirement of coal units.

3) Coal units remaining in service must be reliable during the transition. Given their importance to system reliability, these units must be adequately maintained so that they are available when called upon. It is possible as the system transitions that these units are used less frequently—sometimes only seasonally for reliability purposes—and these new operating patterns may increase reliability risks if not adequately considered. In addition, fuel certainty at the remaining coal units will continue to be essential up through the coal unit retirement dates. As such, coal supply and inventory management strategies will continue to be essential challenges for the duration that coal unit remains in service.

4) Achieving the 2050 carbon neutrality target will require new technologies to meet the reliability challenges posed when achieving carbon neutrality. Assessing technology viability and progress multiple decades into the future is uncertain, but the attributes desirable in new grid sources are knowable based on system needs. What is needed are resources that do not emit carbon and have the dispatchability and flexibility characteristics that are

[62] James R. Robb, North Am. Elec. Reliability Corp., Testimony Before United States Senate Committee on Energy and Natural Resources, Full Committee Hearing On The Reliability, Resiliency, And Affordability of Electric Service, at 9, 10 (Mar. 11, 2021), *available at* https://www.energy.senate. gov/services/files/EB1D7E02-4DFF-A6A9-002341DA34CF.

fundamental to power system reliability (e.g., load-following capabilities). This new technology need is referenced throughout the Carbon Plan as a general need for zero emissions load following resources ("ZELFRs").

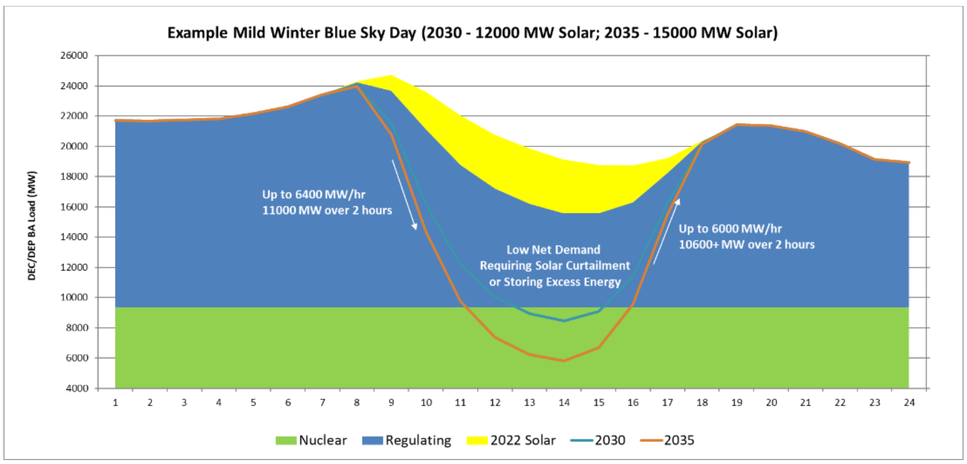
5) As intermittent renewable energy becomes an increasingly large share of generation capacity in DEC and DEP, the remaining electricity demand that must be met by dispatchable resources—that is, the electric load net of renewable energy contributions, commonly referred to as "net load"—will change in timing, shape and magnitude in ways that will place new stresses on the power system.

6) The Companies must ensure that the Carbon Plan portfolio is designed to withstand or, if necessary, recover from extreme events such as the extreme cold weather the Carolinas experienced in January 2018. This resilience is obtained through resource portfolio diversity and planning for the limitations of each type of resource considering the extreme events.

Q. PLEASE ELABORATE ON THE RELIABILITY IMPLICATIONS OF CHANGES IN TIMING, SHAPE AND MANGNITUDE OF "NET LOAD".

A. Again, "net load" is the electric load net of renewable energy contributions. Given the day-night (diurnal) pattern of output, high levels of solar can become increasingly difficult to manage, with two key challenges that must be met in future portfolios: accommodating very low net loads at midday, and managing the associated increasingly rapid decreases and increases in net load as the sun rises and sets. Figure 7 demonstrates the operational excess energy issues that can result from having too many resources and not enough demand, and demonstrates the high net demand ramp rates that the system can experience as high volumes of solar ramp in during the morning and ramp out during the evening.

<u>Figure 7: Low Net Demand and High Net Demand Ramp Rate[63]</u>



The combined DEC/DEP power systems are situated in the Eastern Interconnection, and any frequency deviation is seen by every piece of equipment within the interconnection within milliseconds. And as Witness Holeman explained, most utilities and markets in the Interconnection are also planning to decarbonize their systems to varying degrees, and their resource changes, along with Duke Energy's, will all combine to require tighter controls and mechanisms to maintain system frequency within normal operating bounds.

As the Eastern Interconnection retires synchronous generators and adds new asynchronous renewables, the system will become more susceptible to deviations in the power balance, and thus frequency deviations will increase in

[63] Figure 7 is also replicated in Reliability Panel Exhibit 1.

magnitude. Also, the potential for unscheduled power flows, low and high wind resource output, and low and high solar resource output, will increase as weather systems move across the Interconnection. This change points to the need for adding flexible, dispatchable resources to the portfolio to ensure reliability can be maintained. Additional storage can help with managing the net demand ramp or the excess energy during the net demand valley; however, it can't perform both functions unless you have separate storage assets for both functions. Specifically, referring to Figure 7, if the operator continually charges battery storage to absorb the increasing solar output that is creating the steep net demand ramp in the morning, that storage will not have capacity to again charge during the net demand valley to absorb excess energy. That excess energy could be used in the future for other purposes such as creating hydrogen that can be stored for longer durations and used when needed.

Q. DID THE COMPANIES ENSURE EACH OF THESE IDENTIFIED RISKS WERE APPROPRIATELY ADDRESSED IN THE CARBON PLAN?

A. Yes. The Modeling and Near-Term Actions Panel discusses the Companies' efforts to ensure reliability through the modeling process in significant detail. At a high level, each of the proposed portfolios passed an initial hourly screening to ensure that the resulting portfolio performs at levels of reliability equivalent to or better than the current system configuration. This is a key component to complying with HB 951, which requires that the Commission in developing a Carbon Plan ensure the adequacy and reliability of the grid is maintained or improved.[64] Each of the proposed portfolios satisfied the LOLE metric—a long-established industry standard that measures the probability of shedding firm load to maintain supply and demand balance. However, the Carbon Plan also recognizes the growing need to evaluate reliability using more sophisticated reliability metrics and more granular analyses that can help better identify reliability issues in the future as the grid evolves. Increasing levels of renewable energy and other aspects of grid transformation are changing the nature of resource adequacy and new metrics that move from characterizing the likelihood of experiencing a reliability event, to more carefully analyzing the depth, duration, and source of reliability concerns will become more relevant.

(A) Ressource Adequacy and Future System Resilience Must be Considered in Developing the Carbon Plan

Q. HOW DO THE COMPANIES ADDRESS FUTURE SYSTEM RESILIENCE IN THE CARBON PLAN?

A. NERC defines Bulk Electric System resilience as the ability of the grid to withstand or, if necessary, recover from extreme events. Considerations of resilience look beyond the standard measures of resource adequacy to identify low-probability, high-impact events—including potential weather extremes like extreme cold, ice storms, major hurricanes, flooding, etc.—that can directly affect grid assets or disable critical enabling infrastructure such as transportation networks and fuel supplies. As described in the Modeling and Near-Term Actions Panel, the Companies used standard long-term planning

[64] N.C. Gen. Stat. § 62-110.9(3).

resource adequacy metrics leveraging effective load carrying capability ("ELCC") factors and LOLE, and then conducted additional critical reliability evaluations to account for variations in load and weather to ensure there is adequate supply to serve load.

As also noted in my response to the previous question, as generation mix changes, new planning methodologies and metrics will be needed to assess how extreme events can impact various generation sources and fuel dependencies, thus impacting overall resource and energy adequacy, such as more scenario-based planning, creating measures of potential events and economic impacts of unserved energy, more stochastic modeling tools for resource planning, and the expansion of current resource adequacy metrics.[65] New planning and response measures may also be necessary to ensure that distributed wind and solar resources can be repaired and quickly returned to service after potential widespread damage from an extreme event, man-made or from natural forces. In addition, Duke Energy will need to continue to further integrate resource planning and transmission planning to optimize and proactively plan the system to execute our generation transition.

Q. MR. ROBERTS, WITH YOUR MULTIPLE YEARS OF EXPERIENCE AS A SYSTEM OPERATOR, WHAT ROLE WILL PLANNING

[65] EPRI explored future resource adequacy planning needs in the face of a changing generation portfolio relying more on variable energy resources and natural gas. EPRI, Exploring the Impacts of Extreme Events, Natural Gas Fuel and Other Contingencies on Resource Adequacy (January 2021), *available at* file:///C:/Users/tsdemar/Downloads/3002019300_Exploring%20the%20Impacts%20of%20Extreme%20Events_%20Natural%20Gas%20Fuel%20and%20Other%20Contingencies%20on%20Resource%20Adequacy.pdf.

RESERVE MARGINS AND OPERATIONANAL RESERVES PLAY IN ENSURING RELIABILTY AS THE CARBON PLAN IS EXECUTED?

A. The Modeling and Near-Term Actions Panel addresses the development of the Companies' planning reserve margin and ELCC values, and the additional analytic reliability validation steps in forced outage and weather scenarios with higher levels of renewables to ensure load was served. Mr. Holeman's testimony noted that other regions' decarbonization studies highlighted the potential for planning reserve margins going up in the future to account for retirement of coal, gas, and in some regions nuclear, and the introduction of higher levels of variable energy resources, such as wind, solar, and battery storage—the Companies agree this is a likely outcome. Also highlighted by Mr. Holeman's testimony and the Modeling and Near-Term Actions Panel, new metrics will be required to assess resource and energy adequacy as the generation transition continues.[66]

As the Companies consider the amounts of renewables and energy-limited storage in all Carbon Plan portfolios along with the observations that System Operators are already experiencing today, volatility and ramping, resource and energy adequacy analyses will be critical as DEC and DEP move further into decarbonizing their fleets.

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66 NRRI Insights, The Intersection of Decarbonization Policy Goals and Resource Adequacy Needs: A California Case Study at 12-14 (Mar. 2021), *available at* https://pubs.naruc.org/pub/55D05995-155D-0A36-315C-A161357DA070.

Q. HOW WOULD THE CARBON PLAN PORTFOLIOS PROVIDE FOR RELIABLE ELECTRIC SERVICE BASED ON EVENTS YOU HAVE WITNESSED IN YOUR 32-YEAR CAREER WITH DUKE ENERGY?

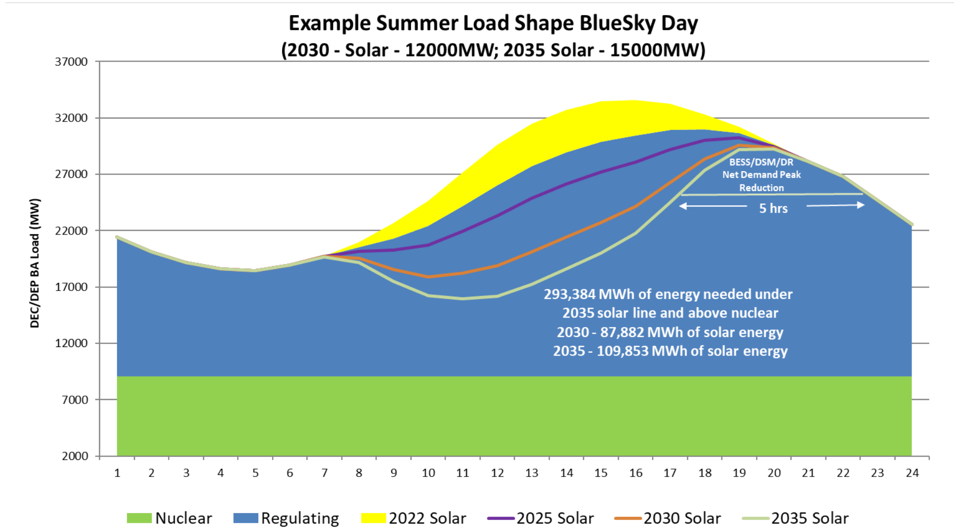
A. Reflecting on my fifteen years as Manager and Director of a power system operations control center, managing the generation, transmission, and reliability functions associated with ensuring customers received reliable electric service, I prepared for and managed the operations of a power system—the same one that will undergo a momentous transformation to meet the carbon reduction requirements of HB 951—through many extreme events including hurricanes, extreme cold weather, extreme hot weather, tornadoes, and flooding events. Similar to the Modeling and Near-Term Actions Panel—which explains the need to conduct additional resource adequacy analysis on the portfolios generated by the capacity expansion plan modeling—my approach to ensuring reliability is maintained or improved through this momentous change cannot be based solely on the output of a model. Instead, it is critical that the Companies consider how a Carbon Plan portfolio would have performed in one or more of these extreme, real-world events and what modifications to the portfolio would be needed to ensure reliable electric service. It should be noted that no two events are the same, with each event bringing its own challenges to ensuring reliable operations and reliable electric service.

Q. CONSIDERING YOUR EXPERIENCE MANAGING SYSTEM OPERATIONS DURING PAST EXTREME EVENTS, WHAT ARE

YOUR OPERATIONAL CONCERNS AS YOU CONSIDER CARBON PLAN DEVELOPMENT AND EXECUTION?

A. I have operational concerns in both extreme heat and extreme cold scenarios, among others. With respect to extreme heat, for example, the Carolinas experienced with multiple days at or above 100ºF in August 2007. Considering how a high renewable Carbon Plan portfolio would respond in that scenario, the operational concern would be on the impact the extreme heat would have on derating the output capability of resources and realizing sufficient energy production for storage if Duke Energy becomes over-reliant on battery storage. As shown in Figure 8 below, the Companies efforts to ensure reliability show that solar production should be adequate during extreme heat periods in the Carolinas provided efficiency losses are not material. The average capacity factors for summer months are in the range of 28%-31% for single axis tracking solar connected to the Duke Energy transmission system. Resources such as 4-hour battery storage along with DSM/DR programs can be used effectively to manage net demand peaks, mitigating the risk of a CAISO-type firm load shed event. There is still a material amount of high capacity factor and flexible resources such as gas CC and CT generation needed to reliably serve high customer demand during extreme heat periods as experienced during August 2007.

Figure 8 – Hot Summer Load Shape with 2030, 2035 Solar[67]



Similarly, and as already described by Mr. Holeman, the Companies have refined their approach to ensuring resource adequacy during severe cold weather events, learning from past experiences with extreme cold, including those that occurred on January 7, 2014, February 20, 2015, and January 2-8, 2018. As mentioned above, none of these cold weather events were the same with each bringing its own operational challenges. For example, with the January 7, 2014 polar vortex event, there was no additional off-system energy available for the Companies to purchase that morning during the peak demand hours, and one of DEC/DEP's neighboring systems had to shed firm load to balance resources and demand. Lessons learned from each of these events have informed the Companies focus on validating reliability in the development of the Carbon Plan portfolios.

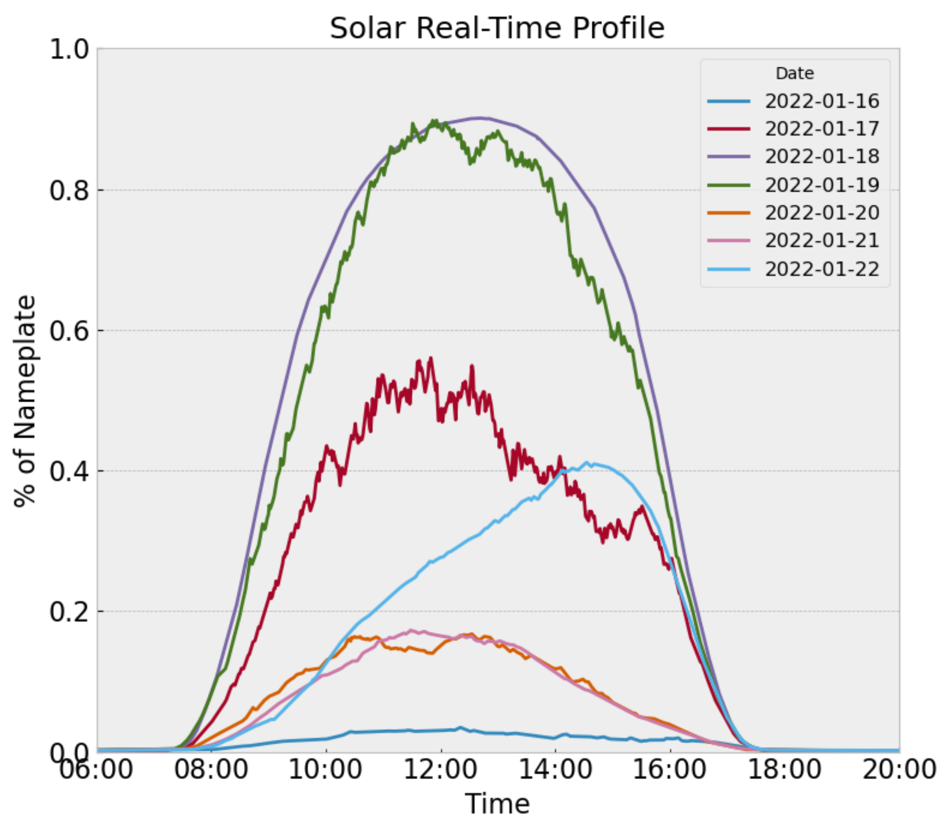
[67] Figure 8 is also replicated in Reliability Panel Exhibit 1.

Q. WHAT SYSTEM OPERATIONS RISKS HAVE THE COMPANIES IDENTIFIED WITH RESPECT TO RESOURCE AND ENERGY ADEQUACY FROM SIGNIFICANT LEVELS OF RENEWABLES AND ENERGY-LIMITED STORAGE?

A. Traditionally, utilities have assessed their resource adequacy by evaluating whether they have sufficient *capacity* resources available to reliably serve electric demand, with consideration given to unplanned outages of generating equipment, uncertainties in load and renewable forecast, fuel availability, high loads and weather-dependent renewable output caused by extreme weather events. With increased levels of renewable generation, utilities must also consider energy adequacy as weather patterns leading up to peak events may not allow renewables to generate (and storage to allocate) energy to meet demand in all hours. Energy adequacy is a particular concern in the winter months during which the Companies' systems experience the highest potential loads due to electric heating during cold weather events. As weather during the winter has high variability, shorter daylight hours, and the potential for consecutive days of low irradiance (low solar output), periods of extended low output from solar are possible. A recent example of this is shown in Figure 9 below for a week from January 2022, which featured multiple winter storm systems that brought rain, snow and ice to the Carolinas. The combination of wintry precipitation and cloud cover suppressed solar output for much of the week, with only two days experiencing relatively high solar capacity factors. During an extreme cold weather period, similarly low solar capacity factors—

even with the significant nameplate solar additions identified in the Carbon Plan—could lead to insufficient energy for serving load if not supplemented with alternative dispatchable, high capacity factor, fuel secure resources.

<u>Figure 9: Real-Time Solar Profile January 16-22, 2022</u>



This variability and potential for extended periods of low solar output drive a need for resource diversity and complementary, dispatchable resources to ensure energy adequacy, including gas generation in the near term and the development of new ZELFRs for the future. The Companies are also cautious to avoid over-reliance on neighboring systems, which are also transitioning their own fleets to resource portfolios that are more heavily reliant on variable energy resources and, therefore, may potentially experience concurrent periods of limited energy and capacity availability.

(B) <u>Operational Experience Will be Critical as Battery Storage is Integrated into the Companies' Systems at Significant Scale While Natural Gas Generation Continues to be a Necessary Bridge Resource to Retire Coal.</u>

Q. PLEASE EXPLAIN WHETHER SYSTEM OPERATIONS CONSIDERS SCALED STORAGE TO MAINTAIN RELIABILITY.

A. All Carbon Plan portfolios include 1,700 MW of expanded pumped storage hydro by 2035. The DEC system has greatly benefited from approximately 2,300 MW (total current capacity) of pumped storage hydro providing operating reserves and flexibility. Through extensive experience with planning, scheduling, and operating hundreds of megawatts of pumped storage hydro, the only current fully operational long-duration storage system available on the DEC system, the Companies understand both the value and the limitations of storage in an integrated electric system.

The Carbon Plan portfolios also plan to rapidly add battery energy storage—approximately 2,000 MW to over 4,000 MW of battery storage by 2035, some paired with renewables. This amount of battery storage is very significant from the perspective of the System Operator. As of December 2021, a total of just 4,600 MW of utility-scale battery capacity had been installed across the entire United States,[68] and accordingly, the industry is just beginning

[68] U.S. Energy Information Administration (EIA), *Battery systems on the U.S. power grid are increasingly used to respond to price* (July 27, 2022), *available at* https://www.eia.gov/todayinenergy /detail.php?id=53199.

to gain operational experience managing these levels of integrated battery storage.

As battery storage technology stands now, scale and time limitations do not make battery storage an operational equivalent for dispatchable gas. Peer decarbonization studies referenced in Mr. Holeman's testimony have noted there will be an ongoing need for resources with the same operational characteristics as dispatchable gas and the retiring coal units that do not require charging. The Companies agree with stakeholders that storage is an essential tool to assist in reliably transitioning to a low carbon future, and Duke Energy is investing in evaluation of multiple storage technologies; however, battery storage is not yet scaled, does not have the necessary duration, and should not be viewed as a panacea.

From a System Operator's perspective, storage is a net energy taker and must be carefully planned when calculating contribution to necessary operational reserves, particularly for seasonal and extreme events. Lithium-ion battery energy storage systems have a round-trip efficiency of 85%. Said another way, 118 MWh of energy used to charge a Li-ion battery will only deliver 100 MWh back to the system. This efficiency is a critical consideration when determining the energy adequacy being provided by a portfolio that has significant variable renewable energy resources and storage. Even when paired with double the amount of nameplate solar, the Carolinas will have days, especially during the winter months, where solar output is insufficient to charge battery storage for upcoming peak demand periods.

Q. PLEASE ELABORATE ON YOUR STATEMENT THAT THERE WILL BE AN ONGOING NEED FOR RESOURCES WITH THE SAME OPERATIONAL CHARACTERISTICS AS DISPATCHABLE NATURAL GAS AND RETIRING COAL UNITS.

A. The best response I can provide is a real-life experience. During the extreme cold weather week in the Carolinas in January 2018, the Companies' coal units operated at very high capacity factors necessary to meet system needs and reliably serve high customer demand. Table 1 below shows the coal units capacity factors experienced during that cold weather week.

Table 1: Coal Generation Capacity Factors for January 2-8, 2018

Coal	Facility	Area	Capacity (Summer MW)	1/2/2018 - 1/8/2018 Capacity Factor
Allen	1	DEC	162	82%
Allen	2	DEC	162	60%
Allen	3	DEC	258	67%
Allen	4	DEC	257	87%
Allen	5	DEC	259	72%
Belews Creek	1	DEC	1,110	99%
Belews Creek	2	DEC	1,110	100%
Cliffside	5	DEC	544	95%
Cliffside	6	DEC	844	93%
Marshall	1	DEC	370	96%
Marshall	2	DEC	370	95%
Marshall	3	DEC	658	68%
Marshall	4	DEC	660	100%
Mayo		DEP	727	95%
Roxboro	1	DEP	379	100%
Roxboro	2	DEP	665	93%
Roxboro	3	DEP	691	94%
Roxboro	4	DEP	698	99%

Using Roxboro Plant (2433 MW) as an example, that coal-fired generation produced 392,786 MWh of electricity at 96% capacity factor during the 7-day period. To produce the same amount of electricity during that 7-day period from solar and storage would require approximately 14 GW of solar at an average winter capacity factor of 20% (very optimistic) and approximately 12 GW of 4-hour battery storage. However, if the system experienced just one-two cloudy days earlier in that week, there would not be enough energy to charge the batteries to make it through the remainder of the week to supply the equivalent amount of energy as was produced from the Roxboro Plant.

Furthermore, January and February data from 2018–2021 show the achievement of 15%-16% average capacity factors from transmission-connected single axis tracking solar facilities connected to Duke Energy's system. This example illustrates the need for a diverse Carbon Plan portfolio to support an orderly energy transition that is not overly reliant on solar and batteries like the recommended portfolios prepared by Synapse for NCSEA et al. and Gabel/Stratagen for Tech Customers. This example also underscores the need for additional high potential capacity factor resources such as gas generation that is a critical part of the resource plan when replacing coal-fired generation.

(C) Maintaining or Improving Reliability of the Grid Requires Recognition of the Real-World Operational Capabilities of Supply and Demand-Side Resources During Extreme Cold Weather

Q. PLEASE DESCRIBE HOW SYSTEM OPERATIONS MUST CONSIDER SOLAR AND WIND FACILITY PERFORMANCE TO MAINTAIN RELIABILTIY IN EXTENDED COLD WEATHER PERIODS.

A. As emphasized above, there will be extended cold weather periods where there are consecutive days of cloudy, potentially snowy weather, followed by a clear, extremely cold morning. If the Companies are dependent on renewable energy resources to serve customer demand and to charge battery storage, energy adequacy becomes a big operational concern. Referring to Duke Energy's response to the Commission in the extreme weather dockets, M-100, Sub 163 and E-100, Sub 173 (the "Extreme Weather Reliability Dockets"), solar capacity factors and resulting energy output are limited during cold weather winter months and can have significant variability from day to day. On average, winter single-axis tracking solar capacity factors range from 15%-16% in the Carolinas with some cloudy, rainy, or snowy days yielding solar capacity factors in the 2%-4% range. For 10 GW of single-axis tracking solar, this means the average daily energy from that amount of solar would be 38,400 MWh, yet a single day's energy from that amount of solar could be as low as 4,800-9,600 MWh. On the low capacity factor days, Duke Energy would not receive enough energy from solar to refill the pumped storage basins, let alone charge four-hour batteries.

In addition, during cold weather, energy from wind facilities can be reduced, as seen during the February 2021 Texas Event. For the Carolinas, wind forecasts show that offshore wind profiles may be more consistent than onshore facilities during these types of events. The winter capacity factors for offshore wind resources are expected to be in the 45%-55% range. However, on January 8, 2018, wind speeds offshore were fairly calm, predicting no appreciable offshore wind generation. Accordingly, offshore wind can also experience limitations during extended periods of extreme cold weather.

Q. ARE THERE ADDITIONAL SYSTEM OPERATIONS CONSIDERATIONS TO MAINTAIN RELIABILTIY IN EXTENDED COLD WEATHER PERIODS?

A. Yes. Energy adequacy evaluations will not only need to consider the potential variability in renewable output and charging/pumping energy needs for storage to ensure reliability in extended cold weather periods, but the potential high load factors for extreme cold winter days will need careful consideration as well. As noted in Duke Energy's response to the Commission in the Extreme Weather Reliability Dockets, the load factor for January 7, 2018 was 86%. This level of load factor indicates very little deviation from hour-to-hour with the energy demanded by the DEC/DEP BA customers in the peak hour at 36.1 GW to the lowest demand hour at 26.1 GW. This high load factor compounds the aforementioned concerns with having energy adequacy for realizing the planned-for ELCC value of a significant amount of storage as proposed in the Synapse and Gabel alternate portfolios.

Q. MR. ROBERTS, PLEASE DESCRIBE HOW SYSTEM OPERATIONS MUST CONSIDER THE IMPACT OF DISTRIBUTED ENERGY RESOURCES AND DEMAND-SIDE RESOURCES IN THEIR OPERATIONAL FORECASTS TO ENSURE RELIABILITY IS MAINTAINED.

A. Distributed energy resources ("DER") and demand-side resources will continue to play a growing role in the Companies' path to decarbonization. In order to effectively manage these increasing resource types, Duke Energy is investing in new tools and associated programs such as the DER Dispatch Project that will allow the Companies to forecast the projected outputs and impacts from DERs for consideration in near-term operational plans. Duke Energy will be able to control DERs when needed to ensure system reliability is maintained. The same cannot be said for demand-side resources for which the impact to customer demand will vary with seasonality and customer usage patterns.

Q. HOW DOES THE PLANNED RETIREMENT OF COAL UNITS IMPACT THE COMPANIES' SYSTEM OPERATIONS RELIABILITY RISKS AS THE RESOURCE MIX TRANSITIONS TO LOWER CARBON RESOURCES?

A. Modeling for the Carbon Plan has shown that most of the Carolinas coal units must be retired by 2030 to meet HB 951 CO_2 emissions reductions targets, and the Carbon Plan retires the final coal units (or ceases coal operations in the case of Cliffside 6) by the end of 2035. However, while continued reliance on coal generation contains risks over and above carbon reduction, there is also reliability risk that needs to be addressed as the Companies exit coal generation. Due to their significant size and on-site fuel storage capability, the Companies' coal units—even as they are planned to be retired—contribute in a substantial way to resource adequacy such that the timing of their replacement must be carefully planned. It is also critical for the Companies to ensure that coal units remain reliable during the transition so that they are available when called upon.

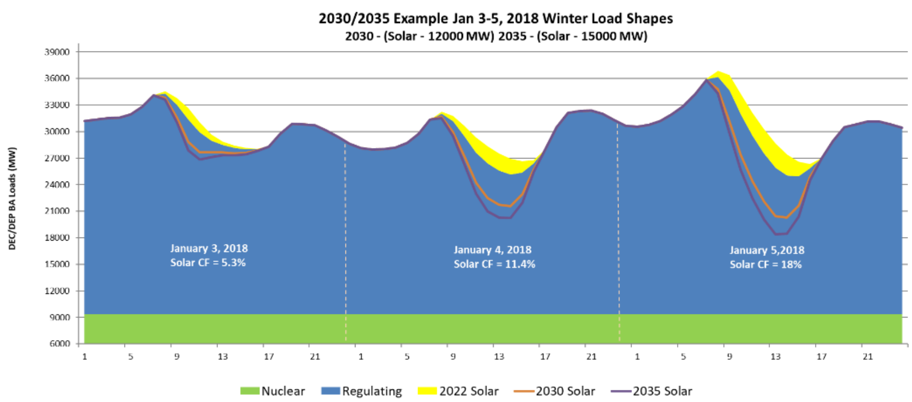
Referring back to Table 1 and observing the capacity factor performance from the Companies' coal generation fleet during the extended period of extreme cold weather in January 2018, replacement resources must be able to perform in a similar manner from an energy adequacy perspective hour to hour, day to day, not hoping to achieve some seasonal average output from variable renewable energy resources sufficient to charge a significant amount of battery storage, to ensure system reliability. Being a native of North Carolina and having observed the weather over many years in the state, there are operational concerns with ensuring the replacement resources are energy adequate replacements considering the weather variability experienced in the Carolinas.

Q. PLEASE EXPLAIN THE IMPORTANCE OF ADDITIONAL GAS GENERATION IN THE CARBON PLAN TO MAINTAIN RELIABILITY AS THE RESOURCE MIX TRANSITIONS TO LOWER CARBON RESOURCES.

A. As Mr. Holeman has already explained, gas resources (CT and CC units and dual fuel conversions) are a necessary reliability "bridge" to achieving carbon neutrality to fill part of the resource adequacy needs created by the retirement of coal units.

In all Plan portfolios, based on the aforementioned coal retirement and generation replacement concerns, additional gas generation capacity is a necessary complement to renewables and storage to provide dispatchable capacity and ensure energy adequacy during winter months when solar output is not well correlated to the Companies' early morning peak load shapes and overall energy demands can remain high for extended periods of time as shown in Figure 10. Not only is solar not well correlated to the Companies' winter load shape, as mentioned previously, winter is the time where solar capacity factors can vary drastically as shown in Figure 10. This day-to-day change would make it difficult, if not impossible, to reliably depend on significant solar energy to store for peaking capacity needed to ensure reliability during an extended cold weather period. Gas technology options have the key reliability advantage of controllable output and sustained output when needed, over long durations, and are additionally more efficient than coal units.

Figure 10: January 3-5, 2018 Solar Production vs Customer Demand[69]



[69] Figure 10 is also replicated in Reliability Panel Exhibit 1.

(D) <u>Duke Energy's Planned Consolidated System Operations Provides Operational and Reliability Benefits</u>

Q. PLEASE EXPLAIN THE BENEFITS OF CONSOLIDATED SYSTEM OPERATIONS PROPOSED IN THE CARBON PLAN TO MAINTAIN RELIABILITY AS THE RESOURCE MIX TRANSITIONS TO LOWER CARBON RESOURCES.

A. As detailed in Appendix R (Consolidated System Operations), Duke Energy is proposing in the near term to consolidate the DEC and DEP system operations functions of Balancing Authority, Transmission Operations, and Transmission Service Provider, in addition to the DEC and DEP transmission service zones in the Joint OATT. This consolidation is an essential step for the Companies to enable efficient and cost-effective operations that facilitate reliability benefits in conjunction with CO_2 emissions reductions targets. As outlined in Figure 11, system operations consolidation has numerous benefits including portfolio flexibility, production cost savings, simplifications with NERC compliance, and transmission service provisions. From the perspective of a System Operator, having a consolidated DEC and DEP operating area provides more tools to both plan for and respond to operating conditions, particularly emergent, stressed or extreme situations—with the added benefits of simplification and more optimized costs and use of renewable energy resources for customers.

Figure 11: Consolidated System Operations Benefits[70]

Flexibility	Production	Simplification
• Optimization of existing resources for operating reserves and regulation • Less solar curtailment • Reduction in CO_2	• Reduced generation costs from optimized use of operating reserves and regulation • Reduced dump energy • Improved market purchases • Improved storage utilization	• NERC standard compliance • One OATT • Single wholesale view
Reserves	**Response**	**Reliability**
• Reduction in day ahead planning reserves • Reduction in planning reserve margin	• Larger balancing area better able to aggregate greater amounts of variable generation and load	• Reserve sharing • Consolidated system operations

(E) Reliability and Operational Considerations Should be Taken into Account in Assessing the Role of Imports in Executing the Carbon Plan

Q. MR. ROBERTS, IN YOUR EXPERIENCE AS A SYSTEM OPERATOR, WHAT ROLE DO IMPORTS PLAY IN ENSURING RELIABILTY AND WHAT ROLE WILL THEY PLAY AS THE CAROLINAS CARBON PLAN IS EXECUTED AND THE ENERGY TRANSITION ADVANCED?

A. The Companies use both firm and non-firm market purchases today as additional tools in their power supply and grid optimization toolbox in very specific and measured ways. The Modeling and Near-Term Actions Panel describe how the Companies mirrored that measured approach by appropriately accounting for non-firm energy imports in reserve margin levels and holding constant reliability benefits from neighboring systems during the modeling reliability validation step.

[70] Carbon Plan Appendix R (Consolidated System Operations) at 2 (Table R-1).

As extensively outlined in in Appendix P (Transmission System Planning and Grid Transformation) and discussed by the Transmission Panel (comprised of witnesses Sammy Roberts and Maura Farver), reliance on off-system imports for reliability and adequacy essentially compounds risk for operations; the importer takes on any inherent risks of the other system that are out of its control, and in constrained conditions the needs of the source's system may be prioritized over those of the importer's system. The Modeling and Near-Term Actions Panel describe how, as neighboring generation fleets decarbonize, more commonality in winter LOLE risks could lower the amount of capacity reserves available across all systems. Simply having transmission import capability is not sufficient. Imports must be backed by power purchase agreements or firm energy deliveries at a minimum. Weather events such as heat waves or polar vortices can span a large geographical area beyond the Companies' service areas and limit the ability to rely on imports to meet energy needs.

There are both reliability and cost risks regarding exposure to transmission capacity contract rollover rights as contracts expire, meaning that as market conditions change, so can contract terms and prices. Non-firm import arrangements use non-firm transmission reservations that are reserved on an as-available basis and subject to curtailment or interruption,[71] creating a risk exposure of not guaranteeing the supply of energy when needed most if those

[71] North Am. Elec. Reliability Corp, Transmission Service Reservation Priorities, https://www.nerc. com/pa/rrm/TLR/Pages/Transmission-Service-Reservation-Priorities-.aspx. (last visited August 3, 2022).

imports are used for resource adequacy. A FERC ruling supporting CAISO transmission wheeling prioritization[72] supports prioritizing transmission capacity serving native load or priority firm service over non-firm imports, and even with firm service there is the potential of pro rata curtailments that can apply to priority firm service under constrained conditions; this essentially can put any import at risk of some level of curtailment. After FERC approved CAISO's transmission prioritization changes, the Arizona Commission Chair expressed concern of potential future curtailments of Arizona's public utilities' firm imports being wheeled through CAISO.[73]

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW RELYING ON IMPORTS CAN IMPACT RELIABILTY?

A. Yes. To further illustrate the risk of over-reliance on imports, California's in-state utility-scale electricity is about four-fifths of the state's electricity retail sales, with the remaining supply coming from out of state resources through firm imports.[74] This has presented problems when increasing temperatures across the broader region divert non-dedicated resources. California experienced a blackout in August 2020 when high temperatures across the

[72] *Order Accepting Tariff Revisions, Subject to Further Compliance*, 175 FERC ¶61,245 Docket No. ER21-1790-000 (June 25, 2021).

[73] Arizona Corporation Commission, News Release: Chairwoman Marquez Peterson Alarmed by Federal Ruling Allowing California to Block Energy to Arizona, *available at* https://www.azcc.gov/news/2021/06/30/chairwoman -m%C3%A1rquez-peterson-alarmed-by-federal-ruling-allowing-california-to-block-energy-to-arizona#:~:text= Despite%20overwhelming%20opposition%20from%20other,mean%20power%20shortages%20for%20Arizonans. (last visited August 3, 2022).

[74] U.S. Energy Information Administration, California State Energy Profile (last updated Mar. 17, 2022), *available at* https://www.eia.gov/state/print.php?sid=CA. (last visited August 3, 2022).

Southwest resulted in no available generation to import, even though firm transmission import capability was available. After the August 2020 firm load shed events, CAISO confirmed the lack of available generation across the Southwest.[75]

The key takeaway from these events is that any additional use of market resources by the Companies for adequacy and reliability should be purposeful in arranging for firm import capability backed by firm resources to serve load, and great caution should be taken in relying on firm and especially non-firm imports to "make up differences"[76] as suggested by intervenors. Also, as Mr. Holeman reminded us, the Root Cause Analysis Report for the CAISO firm load shed events, over-reliance on imports was a causal factor for the events. From pages 6 and 22 of the Report:

> Imports – In total, import bids received in the day-ahead market were between 40 to 50% higher than imports under RA obligations, which indicates that the CAISO was relying on imports that did not have a contract based obligation to offer into the market. In addition to the rule changes the CPUC made to the RA program with regard to imports for RA year 2021, the CPUC may consider additional changes to current import requirements.[77]

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[75] S&P Global Commodity Insights, *California power shortages stem from lack of firm generation capacity: experts say* (August 20, 2011), *available at* https://www.spglobal.com/commodityinsights/ en/market-insights/latest-news/electric-power/082020-california-power-shortages-stem-from-lack-of-firm-generation-capacity-experts.

[76] *See, e.g.*, Gabel Associates Inc., Review of the Duke Carbon Plan and Presentation of a Preferred Portfolio (the "Gabel Report") at 57; Synapse Energy Economics, Inc, Carbon-Free by 2050: Pathways to Achieving North Carolina's Power-Sector Carbon Requirements at Least Cost to Ratepayers (the "Synapse Report") at 33-34.

[77] California Independent System Operator, Final Root Cause Analysis at 6 (Jan. 13, 2021), *available at* http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave .pdf.

> The CAISO Balancing Authority Area (BAA) traditionally relies on electricity imports on peak demand days, meaning that while electricity trading occurs with the rest of the West, on net, the CAISO imports more than it exports. During the extreme heat wave, given the similarly extreme conditions in some parts of the West, the usual flow of net imports into the CAISO was drastically reduced. The CAISO was also limited in its ability to access energy from the Northwest due to a derate at an intertie in the northern part of the system.[78]

Q. PLEASE EXPLAIN THE ROLE OF NEW TECHNOLOGIES TO MAINTAIN LONG-TERM SYSTEM RELIABILITY.

A. The Companies anticipate that both new-to-the-Carolinas technologies such as onshore wind, offshore wind, scaled battery energy storage, and nuclear small modular reactors ("SMRs") as well as "breakthrough" technologies[79] will be required to achieve the 2050 carbon neutrality goal and maintain system reliability. While the specifics of ZELFRs are not fully known at this time, the Companies will need to rely on new resources that have the dispatchability and flexibility characteristics that are fundamental to system reliability at present.

Moving toward carbon neutrality in 2050, the Companies do see significant benefits being realized through deploying new nuclear through SMRs. SMRs have energy density where a couple of thousand megawatts of SMR resources can be located on a relatively small footprint. Second, SMRs are being designed to be dispatchable, a great operational feature that can help with integration of variable renewable energy resources and a feature that we do not enjoy with the PWRs and BWRs on our system today.

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[78] *Id.* at 22.

[79] N.C. Gen. Stat. § 62-110.9(1) (directing that the Carbon Plan should include, among other things, "the latest breakthrough technologies").

Q. HOW DO YOU RESPOND TO INTERVENORS WHO SUGGEST THAT THE RAMP RATE ISSUES THE COMPANIES IDENTIFIED WITH RESPECT TO THE INTEGRATION OF RENEWABLES ARE EASILY ADDRESSED?

A. I disagree. Clean Power Suppliers Association ("CPSA") and its consultant, the Brattle Group ("Brattle") suggest that ramp rate issues have been effectively addressed in other jurisdictions with higher levels of renewables on the system. According to CPSA and Brattle, California and MISO use ramping products, secured at limited costs, to address expected and unexpected needs.[80] In addition, CPSA and Brattle contend that energy storage is "highly effective" at dealing with ramping issues.[81]

First, with respect to CAISO using ramping products effectively, the CAISO does lean heavily on the 5-minute Energy Imbalance Market ("EIM") to help manage its net demand ramping issues. However, looking at Figure 12, as CAISO realized on August 14 as solar resources quickly ramped out toward a net demand of 41,636 MW at 18:35 (45,716 MW gross demand), the import sources including the EIM were insufficient to keep CAISO from instituting firm load shed, even with their gas generation maximizing output at close to 26,000 MW.

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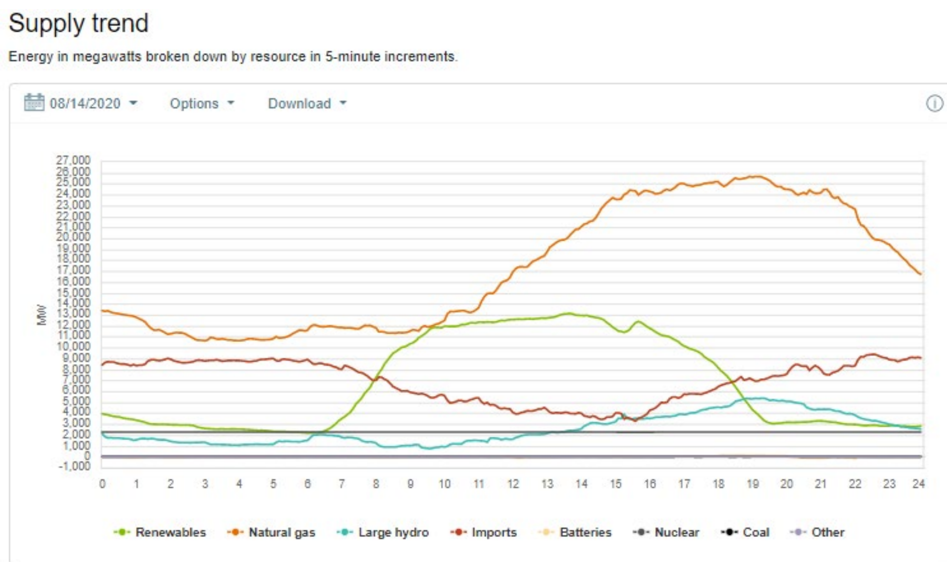
[80] CPSA Comments at 48.
[81] *Id.*

Figure 12: CAISO Power Supply Resources on August 14, 2020[82]



Second, while energy storage resources have many operational characteristics that make them effective for providing fast response reserves—including the ability to commit and ramp quickly as well as wide operating ranges—CPSA and Brattle fail to acknowledge the limitations of storage resources. As stated previously, referring to Figure 7, System Operations would have a difficult time charging battery storage to manage the net demand ramp through absorbing energy from solar rapidly increasing output in the morning, and then trying to use the same battery storage to absorb excess energy during the net demand valley. Furthermore, energy storage resources are energy limited, and their capability to provide operating reserves is dependent on the amount of energy available to charge them, as well as the limited foresight the operator has about future conditions to plan for charging and discharging at

[82] Sourced from CAISO real-time displays on August 14, 2020. Figure 12 is also replicated in Reliability Panel Exhibit 1.

optimal times. A storage resource can only provide as much "up" reserve as it has available stored energy, and only as much "down" reserve as it has headroom to maximum storage volume. Due to efficiency losses when both charging and discharging energy, storage becomes a net consumer of energy from the grid when deploying its reserve capabilities.

Storage is highly capable, but deploying those capabilities to meet reserve requirements must be carefully considered in any reliability analysis. As Mr. Holeman's previous testimony pointed out, while the Companies have significant experience with hundreds of megawatts of pumped storage hydro, the industry as a whole has little operational experience with truly scaled battery storage, and most regional operators have identified this as a clear operational risk for grid transformation.

Q. HOW DO YOU RESPOND TO CIGFUR'S ASSERTION THAT POWER QUALITY ISSUES WERE NOT APPROPRIATELY ADDRESSED IN THE CARBON PLAN?[83]

A. Power quality is impacted by many factors and already regulated under Commission Rules. The Companies considered ancillary services in modeling beyond what has been evaluated in previous integrated resource plan long-term resource models. Power quality is evaluated as a localized parameter based on the load, resources and topology in a specific area. Detailed location-specific factors impacting power quality cannot be included in long-term resource modeling and therefore were not explicitly addressed in the Carbon Plan. The

[83] CIGFUR Comments at 10-11.

Companies evaluate power quality impact during interconnection of individual resources, and it is therefore assumed that the resources to be acquired will meet their Facilities Connections Requirements for power quality. Through interconnection study processes and transmission planning, the Companies will continue to identify and solve power quality issues to ensure reliable service. Finally, the Companies are always engaged in industry forums to understand and apply standards related to power quality such as IEEE standards and NERC standards and guidelines directly and indirectly applying to power quality.

IV. RELIABILITY AND ADEQUACY CHALLENGES TO INTERVENOR PROPOSALS

Q. MR. ROBERTS, DID INTERVENORS HIGHLIGHT THE IMPORTANCE OF MAINTAINING SYSTEM RELIABILITY DURING CARBON PLAN EXECUTION?

A. Yes. A number of intervenors highlighted the critical importance of planning for continued reliability and resource adequacy as the Companies execute the Carbon Plan and integrate higher levels of renewable and intermittent resources. CUCA,[84] CIGFUR,[85] and Person County[86] reinforced the need to ensure adequate dispatchable resources as increasing levels of renewable and intermittent resources are added to the grid. NCEMC agreed with Duke Energy that "generation resource diversity provides flexibility and mitigates the risk of implementation failure that could otherwise result from overreliance on any one

[84] CUCA Comments at 13-14.
[85] CIGFUR Comments at 3-4.
[86] Person County Comments at 16-25.

technology to meet reliability and resilience requirements as the energy transition evolves"[87] and that DEC and DEP forming a single balancing authority area will improve reliability.[88]

The Public Staff also highlights the importance of system reliability in developing the Carbon Plan and finds that the metrics the Companies used to validate portfolio reliability, the 95th percentile expected net load ramp in MW/hour and average combined cycle starts per unit per year, are reasonable.[89] The Public Staff also noted the planning reserve margin remained at 17%, "indicating sufficient capacity resources to meet demand even when the intermittent nature of solar, wind, and energy storage is taken into account."[90] Finally, the Public Staff noted that while intermittent renewables and batteries will present challenges for the Companies' System Operators, they believe sufficient capacity and energy is available in each portfolio, largely attributed to the added resources from the Battery-CT optimization step which likely increases system reliability.[91]

Q. DESCRIBE FROM THE SYSTEM OPERATIONS PERSPECTIVE HOW THE ALTERNATE PLANS PROPOSED BY INTERVENORS APPROACHED RELIABILITY.

A. The alternate plans proposed by the Gabel Report on behalf of Tech Customers and by Synapse on behalf of NCSEA, et al., did not adequately take into account

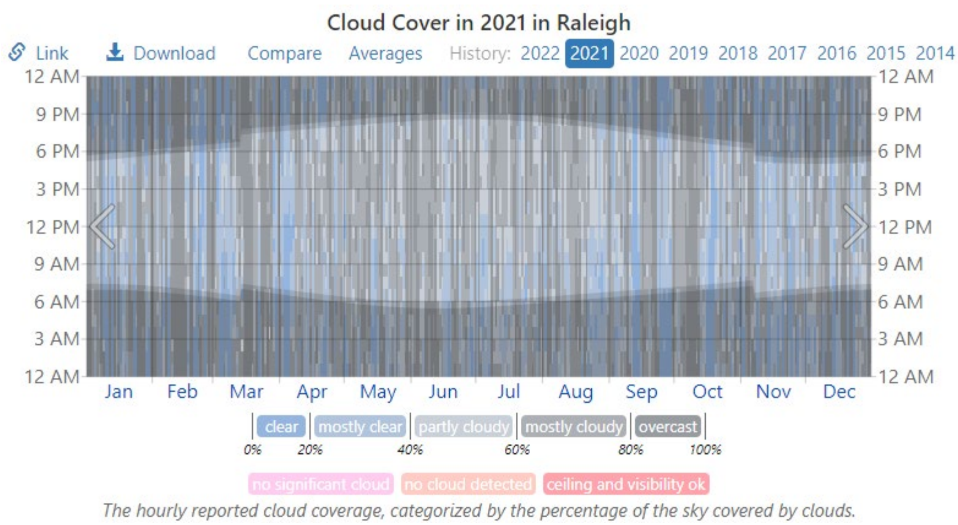
[87] NCEMC Comments at 16.
[88] *Id.* at 9.
[89] Public Staff Comments at 33
[90] Public Staff Comments at 101.
[91] *Id.*

the critically important requirement under HB 951 that the Carbon Plan must maintain or improve the adequacy and reliability of the grid during this accelerated period of system transformation. From a System Operators' point of view, there was not a practical, realistic acknowledgement nor any analysis of the inherent real-time risks and operational challenges of a changing resource mix and associated grid transformation that NERC, SERC, and other regions of the country are recognizing, and that the Companies' Carbon Plan purposefully analyzed and addressed in developing the portfolios. Gabel's and Synapse's alternate plans provided no additional analysis, quantitative or qualitative, assessing adequate power supply and Bulk Electric System reliability considerations that the Companies identified in the Carbon Plan through Appendix Q (Reliability and Operational Resilience Considerations) and through enhanced reliability validation modeling efforts used in the portfolio development process.

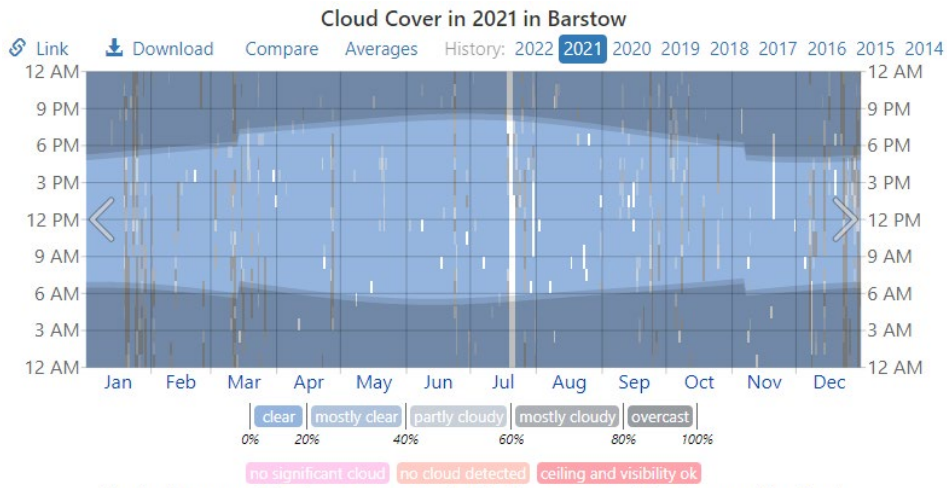
Brattle's alternate portfolio did not take the extra step the Companies' modeling did to ensure reliability of the Portfolios are maintained by modeling extended cold weather periods with high demand and lower solar capacity factors such as the average 15%-16% capacity factors in January and February with some daily capacity factors as low as 2%-4% in the winter being achieved with current single axis tracking solar facilities. Newer solar designs are expected to achieve higher solar capacity factors on average, however the 2-4% capacity factor days can still occur in the future during winter periods. Extended cold weather periods such as experienced in January 2018 is when it would be imperative to have adequate energy to achieve a full state of charge for battery storage for providing peaking capacity.

Gabel's preferred portfolio is highly dependent on front-of-meter solar, behind-the meter solar, solar paired with storage, and stand-alone storage. The Gabel Report's over reliance on solar creates energy adequacy concerns during extended cold weather periods. From an operational perspective, the Carolinas region is drastically different than Southern California where blue sky days are prevalent, making these resources more economical and somewhat more reliable. For example, Figure 12 below shows a chart of 2021 annual cloud cover in Raleigh, NC versus the 2021 annual cloud cover in Los Angeles, CA.

<u>Figure 13: 2021 Cloud Cover for Raleigh, NC and Barstow, CA</u>[92]



[92] Cloud cover information in 2021 for Raleigh, NC and Barstow, CA sourced from https://weatherspark.com/. Figure 12 is also replicated in Reliability Panel Exhibit 1.



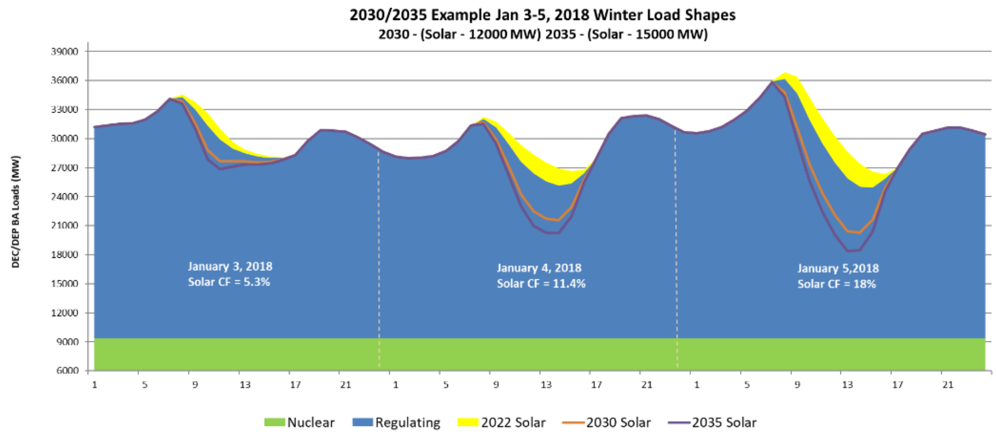
The hourly reported cloud coverage, categorized by the percentage of the sky covered by clouds.

Likewise, the Synapse portfolio is highly dependent on solar, storage, and imported Midwest onshore wind. As stated previously, over-relying on weather-dependent resources during extended cold weather periods carries risks of not getting that hoped-for average weather day, especially when there is a significant amount of storage that needs to be charged with the energy produced from those weather dependent resources. Whereas Midwest wind would add diversity to the overall portfolio, the ability to secure firm transmission service to reliably import the wind energy carries operational risks as well. Duke Energy is planning to continue to assess Midwest wind as a resource, and the first decision point will be the results of the requested 1000 MW firm transmission service request study on the PJM system. Duke Energy conducted its own analysis of PJM providing such firm transmission service with results discussed in Appendix P (Transmission System Planning and Grid Transformation).

Q. MR. ROBERTS, HOW DOES INTERVENORS' APPROACH TO RELIABILITY RELATE TO REAL-WORLD SYSTEM OPERATIONS AT DEC AND DEP?

A. Figure 13 shows actual customer demand and irradiance experience during January 2018 applied to additional solar in the Carolinas. Knowing that the system has to serve all the customer demand at all hours in the blue shaded region under the solar curves and above the nuclear, it would be impossible for me to agree with Synapse or Gabel that the portfolios they could provide energy adequacy for reliably serving the 3-day winter high customer demand shown in the Figure 13, as they are over-reliant on the weather-dependent resources of solar and wind, and the associated storage of energy from these weather-dependent resources. Furthermore, these proposed portfolios retire coal early without effectively providing replacement generation or resources that can achieve high capacity factors for extended periods when needed as demonstrated by Duke Energy's coal generation in January 2018. In conclusion, I do not see these considerations included in any thorough analysis of the reliability that can be provided by their portfolios under these real-life conditions.

Figure 14: January 3-5, 2018 Solar Production vs Customer Demand[93]



V. CONCLUSION

Q. MR. ROBERTS AND MR. HOLEMAN, DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

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[93] Figure 14 is also replicated in Reliability Panel Exhibit 1.

MS. DEMARCO: And I would ask that the Reliability Panel's one exhibit be marked for identification as the next hearing exhibit.

CHAIR MITCHELL: All right. Your motion will be allowed.

(Reliability Panel Exhibit 1 was identified as it was marked when prefiled.)

MS. DEMARCO: All right. The panel is now available for questions from the parties.

CHAIR MITCHELL: Ms. DeMarco, did this panel prepare a summary of its testimony?

MS. DEMARCO: Yes, I'm sorry. If that could be marked as well.

CHAIR MITCHELL: All right. Well, what we will do is we will copy the testimony summary into the record as if given orally from the stand at this moment.

(Whereupon, the prefiled summary testimony of John Samuel Holeman, III and Sammy Roberts was copied into the record as if given orally from the stand.)

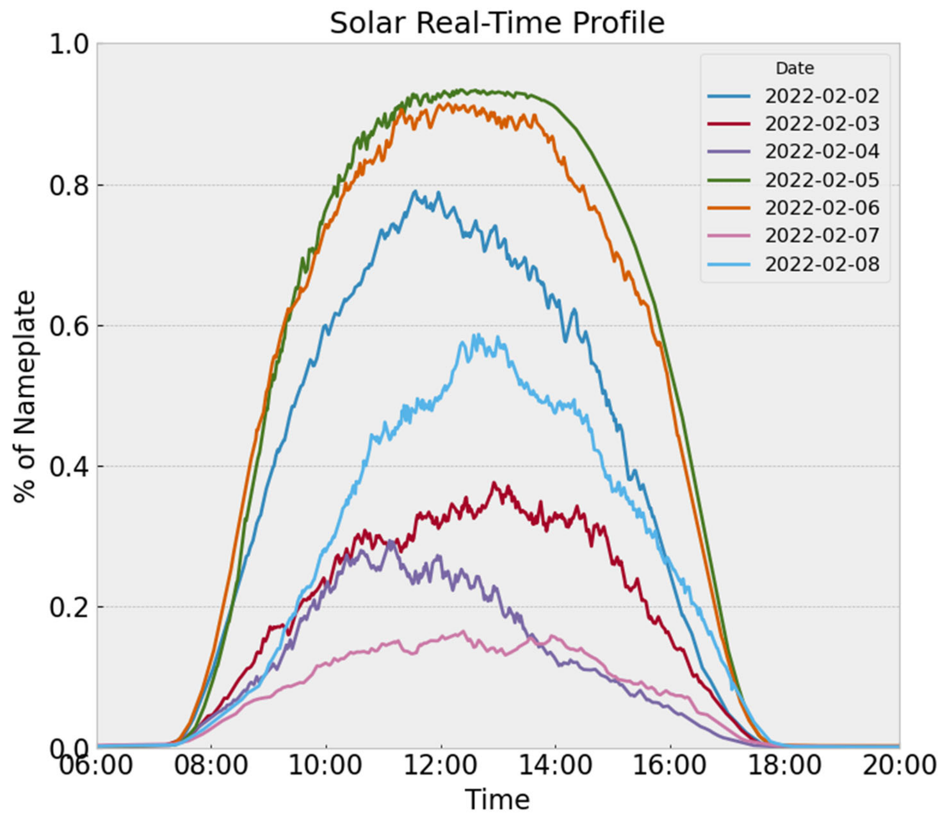
Duke Energy Carolinas, LLC and Duke Energy Progress, LLC
Summary of Direct Testimony – Reliability
John Samuel Holeman III & Dewey S. Roberts II
Carolinas Carbon Plan
Docket No. E-100, Sub 179

As we undergo the energy transition, HB 951 mandates that the Companies must "maintain or improve upon the adequacy and reliability of the existing grid." In other words, maintaining excellence in reliability is non-negotiable as the Companies plan to continue the transition of the electric grid. That this critical directive was written into the law demonstrates that our State legislators understood and placed appropriate safeguards around the electric utility's duty to maintain a secure and reliable electric grid every minute of every day. This provision of HB 951 is a legislative imperative that the energy transition should not and cannot impact the electric utility's core obligation to provide reliable electric service to its customers.

My direct testimony provides an overview of the unique role and real-time obligations of System Operators to maintain a secure, adequate, and reliable grid that complies with NERC Reliability Standards. As the Commission is aware, DEC and DEP are required to comply with federally-mandated NERC requirements to ensure they are able to provide reliable electric service to communities, business, and customers in North Carolina and South Carolina 24 hours a day, 365 days a year and to ensure the collective reliability and security of the Eastern Interconnect grid. NERC has been active in assessing risks related to a transforming electric grid, and its 2021 ERO Reliability Risk Priorities Report specifically highlights the transition of power systems to lower-carbon resources as one of the highest magnitude reliability risks.

For example, wind and solar do not have the same ability to deliver capacity to the DEC and DEP systems at peak demand hours as traditional dispatchable resources like coal, gas and nuclear. Figure 3 from my testimony and reproduced here for my summary illustrates the potential for dramatic variability in solar output from day to day.

Figure 3: 7-Day Solar Profile for February 2-8, 2022



As I explain in my testimony, this figure illustrates a 7-day solar profile that the Companies experienced last winter from February 2-8, 2022. As you can see, solar output reached a high on February 5th of that week (green line), but dropped precipitously just two days later (purple lines). The range of solar outputs over the course of this single week underscores the ongoing need for dependable dispatchable resources to mitigate potential capacity and energy shortfalls.

My testimony also shares a broad industry perspective on the challenges peer system operations functions face in maintaining resource adequacy and reliability through the grid transformation. Duke Energy has a culture of learning from events, inside and beyond its operating region, and proactively making improvements to mitigate current and future risks. Much of the country is either retiring or planning to retire baseload coal-fired, natural gas, and nuclear generation, and the Companies have noted a number of consistent reliability challenges across a number of electric utilities nationwide, including, among other things (1) increased complexity in planning and operations; (2) capacity challenges in seasonal and extreme weather events; (3) increased need for operational flexibility to balance system.

Finally, I discuss the recent outage and load shed events in Texas and California that illustrate in real-world terms the increasing complexity a changing resource mix and higher penetrations of variable energy resources imposes on system planning and operations functions. This commonality in grid transition creates opportunity to advance operational learning and solutions; however, it also may result in less ability to import non-firm energy on neighboring systems' resources to support adequacy and reliability of the grid in broad and prolonged events or in constrained operational conditions.

My colleague witness Roberts' testimony builds upon the background I provide and describes Duke Energy's approach to ensuring reliability in the Carbon Plan. In particular, the Companies evaluated reliability risks and mitigating solutions in the following areas: (1) resource and energy adequacy from renewables and storage; (2) additional firm gas generation; (3) replacement of coal generation capabilities during the transition; (4) the need for zero-emitting load following resources ("ZELFRs") to reach net-zero; (5) flexible generation needs for integrating renewables; and (6) future system resilience to withstand extreme weather events.

Witness Roberts explains how the Companies' Carbon Plan portfolios are designed to perform well in extreme weather events and notes that operational experience will be critical as battery storage is integrated into the Companies' systems at significant scale. The Carbon Plan portfolios plan for the rapid addition of battery energy storage—approximately 2,000 MW to over 4,000 MW of battery storage by 2035. This amount of battery storage is very significant from the perspective of the System Operator; as of December 2021, a total of just 4,600 MW of utility-scale battery capacity had been installed across the entire United States, and accordingly, the industry is just beginning to gain operational experience managing this level of integrated battery storage.

While storage is an essential tool to assist in reliably transition the grid, there will be an ongoing need for resources with the same operational characteristics as dispatchable gas and the retiring coal units. By way of example, witness Roberts points to an extreme cold weather week that took place across the Carolinas in January 2018. His Table 1 shows that the Companies' coal units operated at very high capacity factors to meet system needs and reliably serve high customer demand during that extreme cold weather week.

Table 1: Coal Generation Capacity Factors for January 2-8, 2018

Coal	Facility	Area	Capacity (Summer MW)	1/2/2018 - 1/8/2018 Capacity Factor
Allen	1	DEC	162	82%
Allen	2	DEC	162	60%
Allen	3	DEC	258	67%
Allen	4	DEC	257	87%
Allen	5	DEC	259	72%
Belews Creek	1	DEC	1,110	99%
Belews Creek	2	DEC	1,110	100%
Cliffside	5	DEC	544	95%
Cliffside	6	DEC	844	93%
Marshall	1	DEC	370	96%
Marshall	2	DEC	370	95%
Marshall	3	DEC	658	68%
Marshall	4	DEC	660	100%
Mayo		DEP	727	95%
Roxboro	1	DEP	379	100%
Roxboro	2	DEP	665	93%
Roxboro	3	DEP	691	94%
Roxboro	4	DEP	698	99%

Using the Roxboro Plant as an example, that coal-fired generation produced 392,786 MWh of electricity at 96% capacity factor during the 7-day period. To produce the same amount of electricity during that 7-day period from solar and storage would require approximately 14 GW of solar at an average winter capacity factor of 20% (very optimistic) and approximately 12 GW of 4-hour battery storage. However, if the system experienced just one-two cloudy days earlier in that week, there would not be enough energy to charge the batteries to make it through the remainder of the week.

Last, witness Roberts addresses reliability issues the Companies identified in the alternative plans proposed by certain intervenors. At a high level, these alternative plans do not meet HB 951's mandate to "maintain or improve upon" the reliability of the grid. Both the Gabel Report and the Synapse alternate portfolio over-rely on weather-dependent resources like solar, storage, and imported Midwest onshore wind.

In short, based upon our decades of experience planning the DEC and DEP systems and serving in roles of primary responsibility for ensuring compliance with NERC Reliability Standards, witness Roberts and I have confidence that the Companies' proposed Carbon Plan portfolios meet the HB 951 mandate to "maintain or improve upon" the reliability of the grid, while the alternative plans would create unnecessary reliability risks for our customers during this critical energy transition.

This concludes the summary of the Reliability Panel testimony.

CHAIR MITCHELL: All right. With that, are the witnesses available for cross examination?

MS. DEMARCO: They are, thank you.

CHAIR MITCHELL: Okay. All right. Who's up first?

MR. SMITH: Avangrid requested five minutes of time, but we don't have any questions for this panel at this time.

CHAIR MITCHELL: All right. Thank you, Mr. Smith.

MR. BURNS: CCEBA also requested time, but we're gonna reserve our questions for rebuttal, because they're more properly directed at the topics in rebuttal.

CHAIR MITCHELL: All right. Thank you, Mr. Burns.

MS. CRESS: I get the coveted spot right before lunch once again.

CROSS EXAMINATION BY MS. CRESS:

Q. Good afternoon, gentlemen, Christina Cress for CIGFUR. I am gonna save most of my questions for rebuttal, but I do have a few to ask you today.

You testified on page 23, and I'll give you a second to get there.

A. (John Samuel Holeman, III) We're there.

Q. You testified on page 23 of your direct testimony that an evolving resource mix with less base-load generation and more variable resources -- I'm sorry, more variable generation inverter base resources, storage and distributed energy resources leads to potential generation or transmission insufficiencies; is that right?

A. That is correct.

Q. Okay. And the subcritical coal plants that are scheduled to retire are located in North Carolina, correct?

A. Subject to check, I believe that is correct.

Q. And those retirements will significantly reduce the generation located in North Carolina that's available to dispatch near load; is that right?

A. They will be retired; that is correct.

Q. Is it fair to say, then, based on the location of the retiring coal fleet, that power quality issues as the Carbon Plan is implemented is a greater risk for Duke's North Carolina ratepayers as opposed to its South Carolina ratepayers?

A. No, I would not agree with that. I think the completeness of the Carbon Plan -- if you look at the

Carbon Plan, if you look at House Bill 951, it talks about we have to make sure that we maintain or improve the reliability of the existing grid. That's not a nice to have, that's not an if you can, we've got to. And I think the -- as we've evaluated, and as system operators we've looked at the Carbon Plan, we've looked at the reliability validation steps, we believe that the needs to replace capacity -- excuse me, replace capability -- and that's -- for a system operator, that's what's important. The fuels and the technology are facts, but what really matters is the capabilities that are either being retired or being replaced.

And I think the Carbon Plan that we're proposing takes the step to replace capability before you retire capability. If we get that out of order, that's not gonna be a good day. But the Carbon Plan talks about keeping it in order. Replace before you retire. So I believe I'm confident after 38 years in this industry in the operations area that if we keep that order right, we'll be able to deliver what's mandated in House Bill 951.

Q. I'd like to follow up on something you just testified to.

You said it's very important that we get the

order right, replace then retire; is that correct?
A. That is correct.
Q. Help us understand what could happen if that order is not followed sequentially.
A. Well, for a system operator, we have what are called operating reserves. And you've heard a lot of discussion around planning reserve margin, and that's a necessity or it's necessary in planning space, but when you get into operating space, it's not sufficient.
We have to have capabilities that have been defined by NERC, and they're listed throughout the testimony, even in the Carbon Plan, that NERC has defined as essential reliability services or interconnected operation services. They're capabilities like ramping, going on automatic generation control, being able to be dispatched, being able to run for long durations of time without worrying about variability or intermittency.
And as I look at the Carbon Plan, it is an all-of-the-above plan. And as an operator, that's what I'm looking for. At the end of the day as an operator, all I really care about is what are these plans, what are these portfolios delivering for my operators so that they can deal with the variations that occur every

day in a control center. And they are the people, after all, that are making decisions that affect over 4 million of our customers in North Carolina. Their job is, to keep it really simple, to keep the lights on. And that's been our history in North Carolina and Duke Energy in the Carolinas.

And so those are the capabilities we've got to replace before we retire them. And I think, as operators, we're obligated under the NERC reliability standards, NERC's -- the North American Electrical Reliability Corporation -- the Electric -- the ERO -- the Electric Reliability Organization -- established by FERC to ensure reliability across the broader North American grid.

Q. Thank you for that. And if these capabilities are not replaced before they are retired, help us understand what the risks are.

Are there risks of blackouts, brownouts? Can you speak to that a little bit?

A. And I would ask my colleague, Mr. Roberts, to join in as well, he's got -- between the two of us, we've got going on 70 years of experience in this space. I'm kind of a little bit embarrassed to say that. I guess I'm getting old. But what happens is, operators -- and we reference this in the testimony. Operators use what's called an operational toolbox. That's kind of a figure of speech, but it's an operational toolbox.

And what you want to do is give your operators as many tools in that toolbox as you can. Regulating reserve, contingency reserve, AGC capable resources. AGC is automatic generation control. You can put it under the control of a computer that drives the dispatch of it. Regulating reserves is being able to respond to the changing load demands of our customers which change -- we monitor it every four seconds, but it's really changing all the time. Operating reserves, which are reserves -- that's kind of the general term. It covers everything from load forecast air to forced outage rate to changes in whether patterns.

So you want to equip your operators with as many operating reserves as you can, because at the very bottom of that toolbox are operating -- are tools that directly impact our customers. They're tools like public appeal, they're tools like controlled load shed. There's tools like under-frequency load shed. There's tools like under-frequency generation protection. When you get down to those, you want to provide your operators with enough tools to stay away from those.

Now, if we have to use them, we will. We're trained to use them. We go through drills where we train our operators in simulation to be able to use it. But in my 38 years with the Company in operations, we've been able to not have to use those customer-impacting tools. Mr. Roberts?

A. (Sammy Roberts) Yeah. I would just refer back to your power quality question. We are going -- as we make this generation transition, we are going to have to change some of our processes. One of them that's already -- you know, we're updating, enhancing is associated with inverter base resource commissioning. And so with that, we are gonna ensure -- you've seen -- you've heard of the Odessa event in Texas, and there's been some events in California where you've had multiple inverter base resources trip due to a state -- or a power system fluctuation fault.

One of the things we're enhancing with that process is not just upfront checking to make sure the inverter base settings are correct and that they're designed and implemented correctly, but also ongoing performance and monitoring. What happened during those fault scenario.

So there is a lot of due diligence going forward that we're going to need to proactively put in place, similar to the RZEP projects, but proactively put in place to ensure that power quality is maintained. We have facility connection requirements, such that every facility that connects to our system, new resource that connects to our system has to meet certain requirements in order to ensure that power quality.

A. (John Samuel Holeman, III) And I would add, I mean, as you look at the Carbon Plan -- and several witnesses, witness Bowman, witness Snider spoke to the four pillars, and it's reliability, it's affordability, it's executability, and ultimately it's carbon reduction. And so these tools, these assets that we're talking about that come together, the inverter base resources, the gas resources, the nuclear resources, the pump storage and the hydro facilities that we currently have, they work together.

It's kind of a training mission or message we always send to our operators. Don't put all your eggs in one basket. You're sitting there on the console, you don't want all of your plans for the day to depend on one particular type of resource or one particular tool. You want a diverse portfolio so that you can have diverse and deep set of tools to deal with the challenges you face every day.

We need solar. We need storage. We've got over several years, 400 -- 4,000 megawatts of solar currently on the system that we're learning and growing and getting better at managing every day. We've got a small amount of battery storage, but we've got over 2,400 megawatts of pump storage storage that we have industry leading experience there. It's longer duration, tremendously flexible.

That's the type of -- that's the type of tools that we have in your toolbox currently, and in order for us to comply with the mandate on adequacy and reliability in House Bill 951, we're gonna have to make sure that toolbox for our operators stays deep and diverse.

Q. Thank you for that.

Mr. Roberts actually brought something up that prompted me to introduce an exhibit I wasn't planning to exhibit -- or to introduce, but thank you.

MS. CRESS: I, at this time, will

mark -- request, actually, that the Chair allow to be marked for identification as CIGFUR II and III Reliability Panel Direct Cross Examination Exhibit Number 1, which is the 2022 NERC summer reliability assessment.

(Pause.)

CHAIR MITCHELL: I was thinking it was already in the record, but we have a different document in the record. All right. Document will be marked for identification CIGFUR II and III Reliability Panel Direct Cross Examination Exhibit 1.

MS. CRESS: Thank you, Chair Mitchell.

(CIGFUR II and III Reliability Panel Direct Cross Examination Exhibit Number 1 was marked for identification.)

Q. Gentlemen, do you have the docket in front -- or the document, excuse me, in front of you now?

A. Yes.

Q. Could you please turn to page 6.

A. (Witness complies.)

Q. And, Mr. Roberts, I'll ask you to look at the last bullet point listed under "Other Reliability Issues for Summer."

A. (Sammy Roberts) Yes.

Q. Can you speak to whether -- first I'll have you read this into the record, please.

A. "Unexpected tripping of solar photovoltaic resources during grid disturbances continues to be reliability concern."

Is that the correct bullet?

Q. That's correct.

A. "In May and June 2021, the Texas interconnection experienced widespread solar PV loss events like those previously observed in California area. Similarly, four additional solar PV loss events occurred between June and August 2021 in California."

Q. Is this the same tripping of inverter base resources, or is this related to the tripping that you were just testifying to in California and Texas?

A. Yes. It's referring to the Odessa event and like the Blue Cut tripping in California, so.

Q. Is that a risk that you-all are worried about for North Carolina?

A. No. Once again, with respect to, you know, proper commissioning and proper ongoing monitoring and enforcement through our facility connection requirements and our interconnection agreements, you can ensure that those inverters will have proper ride-through with these events. And that's been identified in most all of these reports.

Q. Thank you for that. I'm gonna go back to the power quality issue that we were talking about a little bit earlier, if we could. Has -- let me back up.

Is some of the retiring capacity currently used for bulk transmission system support purposes, in addition to following load?

A. Yes. So there are -- and I'm assuming you're referring to our coal-fired generation?

Q. That's correct. Thank you.

A. So some of that coal-fired generation does have what we call reliability must-run conditions. And so at certain load levels, you need to must-run that coal generation in order to provide that reliability function.

Q. Can you give a percentage of how much of the retiring capacity is used for that bulk transmission support versus as a load following resource?

A. Yeah. It's -- I really wouldn't call it bulk transmission support, but local -- localized regional transmission support. For example, with Roxboro, it does currently provide voltage support for Harris local voltage. And, for example, Belews Creek does provide northern region voltage support.

As we discussed yesterday with Commissioner Clodfelter, the McGuire Marshall 230 kV lines, Marshall has a must-run condition with respect to power flow control for mitigation of contingencies. And as I discussed yesterday, at certain load levels, these coal-fired generators are usually economically dispatched anyway.

Q. Has Duke studied how much new replacement capacity will be needed in North Carolina to account for the retiring capacity that's currently used for bulk transmission system support?

A. So there's -- there's -- it's not always a megawatt solution, right? For example, with the voltage support, you can have replacement generation in the general area. It would be most beneficial to try to replace it on site in Roxboro to take advantage of the cost savings with respect to transmission infrastructure. However, you could replace it in the general area and also provide, like, a static VAR compensator, or Commissioner Clodfelter was recommending we look at a synchronous condenser.

So those two items provide voltage support, synchronous condenser or static VAR compensator.

Q. Can power quality be impacted without sufficient bulk transmission support?

A. Yeah. I mean, power quality can be impacted by numerous things, but transmission -- ensuring that you have adequate transmission support or adequate transmission, period, can impact power quality, in general.

Q. And speaking of power quality, I just want to be sure that we're working under the same definition of what power quality means.

What is your definition of power quality?

A. Right. So they're -- within our General Statutes, we're required to maintain voltage within certain levels for the customer. And so maintaining voltage within those parameters is an example of power quality.

Q. Well -- I'm sorry. Go ahead.

A. I mean, avoiding some of the events that Mr. Holeman was talking about with brownouts, for example, that would be an example of maintaining power quality.

Q. What are some other examples of maintaining power quality?

A. I mean, it's all about meeting the NERC standards, which are the minimum requirements for maintaining bulk electric system reliability and avoiding those voltage disturbances and avoiding brownouts, that sort of thing.

Q. So are you -- I'm sorry.

A. (John Samuel Holeman, III) I'll just offer a little bit here. So you hear a lot of times people, like Mr. Roberts and myself, talk about reliability, security, and things like that, and sometimes you may wonder what does that mean. So just from an operator's perspective, reliability is operating a system within its limits. And the system is made up of thousands of components. So if you're operating reliably, you're keeping all those devices within their limits. And that's a challenge. And there are NERC standards that drive us to do that.

Security is prepositioning the system so that, when an unforeseen and predictable event happens, sometimes called a contingency, the system lands reliably. So that's, kind of, a broad general definition of quality. If you're operating within your limits and you're prepositioning the system through generation changes or transmission changes so that when something happens you land reliably, you're ensuring continuity of service. You're ensuring quality of service over time.

Now, that's something our operators manage 24 by 7 by 365 in our ECCs in Charlotte and here in Raleigh. But that's the world of a system operator. That's what they're doing on the generation side. Trying to make sure we're operating within limits and prepositioning the system to be able to withstand an unforeseen contingency and land reliably.

Q. Thank you for that.

Mr. Roberts, I just want to follow up with you on your answer to that question, which I think I heard you use power quality and reliability interchangeably; is that a fair characterization?

A. Yeah. Usually when people talk about power quality, you're talking about more local customer impacts. And so to the extent of, you know, what it takes to provide that local customer quality of service power quality, that's usually what I get back to. When I hear about reliability, I'm thinking about bulk electricity system reliability, such as Mr. Holeman was referring to. But -- so that local customer impact is more the power quality I was referring to.

Q. And did the Companies analyze power quality issues when it was developing the Carbon Plan?

A. So once again, with power quality being kind of a local customer impact, that will be managed through when we connect these resources, these incremental resources, ensuring that these resources are meeting our facility coordination requirements, or connection requirements, excuse me.

Q. But what happens when a power quality incident occurs after a resource is interconnected?

A. I'm not following your question.

Q. What happens -- let's say, hypothetically, a customer experiences a power quality incident at their facility. How does Duke handle that?

A. So we have people within our Company that can go out and address harmonics, they can monitor and make recommendations to the customer with respect to resolving that power quality issue. There can be a root cause done to isolate the cause of the power quality issue and resolve in that manner.

Q. So it sounds like you're talking about somewhat of a diagnostic assessment to try to pinpoint the cause of the power quality issue and then fix it?

A. Right. But usually, you know, what we try to do is prevent the power quality issue to begin with. Now, it can be associated with the customer's equipment, right? If they've added load, if they've added intermittent load, that sort of thing, and we didn't know about it, that could be the creation of the power quality issue. Or some kind of variable speed drive that creates harmonics.

Q. And to flip it around, is intermittency of resources also a contributing cause to power quality issues?

A. Intermittency of solar in the past connected to distribution has created a power quality issue, but we resolve that issue through what we call a stiffness factor associated with connecting solar to distribution substations. So once again, we try to -- we like to do that proactively versus reactively.

Q. What was the issue that it caused that you were referencing in your answer to the last question?

A. Subject to check, you know, I think the intermittency associated with the solar, because of the magnitude of the solar connected to that T to D sub was creating an issue where it was interfering with the customer's processes, and so it had to be resolved.

Q. And when you say "customer's processes," am I correct to assume that you're talking about an industrial customer?

A. Subject to check, I believe it was an industrial customer.

Q. Are industrial customers, in your experience, more susceptible to power quality issues than other classes of customers?

A. So I'm not an industrial power quality expert. I know that when I was in charge of training for system operators, our system operators would have large account managers come over and talk about these things can interrupt these large industrial customers and here's the impact. And so this was what we're doing to try to prevent those from happening.

Q. Is it fair to say that industrial customers are more sensitive to deviations in power quality?

A. I mean, industrial customers probably see a larger impact from an economic perspective.

Q. Because it interferes with their processes like you were just testifying about; is that fair?

A. That's fair.

Q. Okay. So going back to whether power quality was considered in the Carbon Plan when the Company was performing its reliability analysis.

And I understand, Mr. Roberts, from your testimony, that power quality was not considered in the Carbon Plan; is that correct?

A. Right. We believe it's addressed from a local perspective and with those facility connection requirements that I was discussing.

Q. Can you help us understand why localized data can't be aggregated and then reported on, say, in the next 2024 Carbon Plan filing?

A. Localized data in what regard?

Q. With respect to power quality incidents.

A. I mean, I'm sure we collect power quality data associated with various customers.

Q. So is there any reason why that data can't be aggregated and then reported to the Commission in the 2024 Carbon Plan filing?

MS. DEMARCO: Objection. Chair Mitchell, she's asking him to testify to something that's he's indicated he's not familiar with.

MS. CRESS: Chair Mitchell, he just testified that he is sure that the Company collects data regarding power quality incidents, and my question was could that data be provided to the Commission in the 2024 Carbon Plan filing. So I'm not really sure what the basis of Ms. DeMarco's objection is.

THE WITNESS: I'll answer the question.

CHAIR MITCHELL: All right. Let me rule on the objection first, please, sir. I'll overrule the objection, and he can answer to the best of his knowledge and ability.

THE WITNESS: So with my knowledge, I don't know what data could be reported or aggregated.

Q. But --

A. (John Samuel Holeman, III) Go ahead and finish.

Q. No, no, go ahead, please.

A. So as I look at the Carbon Plan, if you look at 25 or 27, 28 years, it's over 200,000 hours. And I think witness Snider talked about innumerable combinations and perturbations. You've got to get the foundation right in order to get the power quality right. Mr. Roberts is correct, power quality at the customer level is generally driven by the local situation plus the local contingencies that have happened. If we're gonna get that right in the long run, we've got to get the foundation right. We've got to have this transformation of the grid done correctly.

And I think Mr. Roberts and I agree that the portfolios in the Carbon Plan give the operators the tools, the capabilities to do that over time. And why it's so important -- and we're talking about the most critical of the critical infrastructures in North America. It's vitally important for our four-and-a-half million customers in North Carolina. They depend on it every day of every week. And our operators take that really seriously, whether they're our balancing operators or our transmission operators or even with customers, individual customers, our operators in our distribution control centers.

So -- but I guess my point would be, if we don't get the foundation right, if we don't get the base of the pyramid stable and strong in this significant transformation of the most critical of critical infrastructures, we're gonna have problems. But I don't believe -- I believe that our portfolios in the Carbon Plan provide that foundation.

Q. Thank you for that.

MS. CRESS: And before I start a new line of questioning, I just want to check in with Chair Mitchell. And I'm looking at the time and asking if you want me to proceed?

CHAIR MITCHELL: Plow ahead.

MS. CRESS: Okay. Thank you.

Q. I want to talk a little bit about the metrics used for the reliability analysis in the Carbon Plan.

Can you speak -- as the panel, can you speak to those metrics?

A. (Sammy Roberts) Yes. We may have to defer to the modeling group if you want really specifics on the data analytics.

Q. Tell me what you can speak to.

A. With respect to -- I know that the modeling group, with respect to reliability, as your witness Snider looked at four steps: EnCompass with resource selection, EnCompass with production cost modeling, the battery CT optimization, and then the reliability verification.

Q. Were there any specific tools you used to create a baseline -- not to use that word again, but to create a baseline for the reliability of the grid as we sit here today?

A. So, I mean, we address resource adequacy and -- in the 2020 IRP, and we address, you know, looking at each one of these Carbon Plan models. And that's basically looking at the reliability of those portfolios. If we looked at today, you know, from our system operations perspective, what we have is history up to this point. And we know we've been able to serve our customers reliably through extreme weather events, through quickly recovering from hurricanes, those types of events. So our current-day system operations experience would tell us that our portfolio and system is very reliable.

Q. Does the Company currently track MAIFI, Momentary Average Interruption Frequency Index?

A. So I'm not familiar with all the reliability metrics. I know a little bit about we track SAIDI, we track FOMI [sic]. So there's -- there's metrics that we report to this Commission with respect to interruptions.

Q. Can you define those acronyms you just said for the record, please.

A. I cannot right now, no, sorry.

Q. Okay. And MAIFI is something that the Company tracks or does not track?

A. I haven't heard the term MACI (phonetic spelling).

Q. MAIFI.

A. Could you spell that out?

Q. So yeah. The Momentary Average Interruption Frequency Index, MAIFI.

A. I'm not familiar with that.

Q. You're not familiar with that.

So does the Company, to your knowledge, track MAIFI data?

A. We may, but I'm not familiar with it.

A. (John Samuel Holeman, III) So we track SAIDI and SAIFI. That's System Average Duration of Interruptions, and -- I'm sorry. Excuse me.

So we track SAIDI and SAIFI, that's System Average Duration of Interruptions and System Average Frequency of Interruptions. I don't know if that lines up with what you were talking about, but it is outage duration/outage frequency oriented.

Q. So, Mr. Holeman, is it fair to say that the Company does not currently track MAIFI?

A. I can't confirm that or deny it, I'm not aware.

Q. If the Company was directed to track MAIFI, could they?

A. (Sammy Roberts) I mean, if we were directed by this Commission to track it, we would probably have

to quantify and track it.
Q. Would MAIFI be a good indicator of power quality incidents as the Carbon Plan is implemented?
A. Not knowing exactly how it's calculated or what it references, its inputs, I couldn't say yes or no.
Q. On pages 83 to 84 of your direct testimony.
A. (Witness peruses document.)
Okay.
Q. You indicate that detailed location-specific factors impacting power quality cannot be included in long-term resource modeling, and therefore were not explicitly addressed in the Carbon Plan; is that correct?
A. What line are you referring to?
Q. I'm reading it off of a different document, so that's why I'm asking you if it's correct.
A. Okay. I would need -- to make sure you're reading verbatim, I would need to know what line you're referring to. Could you repeat it again I'll see if I can find it?
Q. Sure, Mr. Roberts, let me get that for you. Okay. Are you on pages 83 to 84?
A. Yes.

Q. Okay. And are you able to look at line 20?

A. Yes.

Q. Okay. So you're with me?

A. Yes.

Q. Line 20 to 22?

A. Yes.

Q. You testify that detailed location-specific factors impacting power quality cannot be included in long-term resource modeling, and therefore were not explicitly addressed in the Carbon Plan; is that correct?

A. Yes, that's correct. That's where I was stating that we believe that is addressed through local considerations and things like our facility connections requirements and resources.

Q. But could you consider the number of power quality incidents that occur between one point in time and another point in time?

A. I'm sure, over time, you could probably look. If it was well defined and -- I don't know that we don't track it already, but anyway, you could look at trends.

Q. Okay. And the Southeast Energy Exchange Market, otherwise known as SEEM, establishes a region-wide automated intra-hour trading platform; is that right?

A. That's correct. It's just an extension of our current hourly bilateral trading.

Q. And the goal of SEEM is to utilize unused transmission capacity; is that correct?

A. It's to use, as available, non-firm transmission capability, yes.

Q. And was SEEM analyzed as part of the Carbon Plan?

A. So being just an economic energy exchange, not a capacity market, so it wouldn't be something that could be selected in a capacity expansion model. It was not part of that analysis.

Q. And so witness Roberts testified on the Transmission Panel extensively about various transmission upgrades and how they are categorized and how they are characterized. And I'm asking if SEEM and the ability to exchange transmission capacity was evaluated as part of the Carbon Plan transmission planning.

A. SEEM doesn't exchange transmission capacity, just economic energy.

Q. Okay. Fine. Nothing further. Thanks.

CHAIR MITCHELL: All right, Mr. Snowden? We'll break at 12:45.

MR. SNOWDEN: Okay. Thank you.

CROSS EXAMINATION BY MR. SNOWDEN:

Q. Mr. Roberts, I'd like to follow up on a couple of questions that CIGFUR's counsel asked you regarding power quality and distribution circuits, and specifically the stiffness; do you recall that?

A. (Sammy Roberts) Yes, I do.

Q. And would you agree that those circuit stiffness issues you were discussing relate to power quality issues that were experienced by certain Duke customers on distribution circuits back on 2014 or 2015?

A. Subject to check. It's been several years ago, yes.

Q. Okay. And do you recall that, in July of 2016, the Company began implementing what it called the circuit stiffness review, which was -- well, do you recall what that is?

A. Subject to check, yes. It limits the amount of solar that can connect to a transmission to distribution circuit based on the capabilities of that transmission to distribution substation.

Q. Okay. Thank you. And the intention of that screen was to identify interconnections that could cause power quality issues on distribution circuits, right?

A. That's correct.

Q. Okay. And do you recall that some disputes arose with regard to Duke's implementation of that criterion?

A. I don't remember the exact disputes, but I'll take your word for it.

Q. Okay. All right. Do you recall that a settlement agreement was filed with this Commission between interconnection customers and Duke, I believe, in August of 2016?

A. Yeah, I don't recall that settlement agreement.

Q. Okay.

A. Once again, I'll take your word for it.

Q. Thank you. Do you recall whether that settlement agreement included additional language for interconnection agreements that essentially put interconnection customers on the hook for any power quality issues that arose due to stiffness issues?

MS. DEMARCO: Objection. Chair

Mitchell, he's just testified that he was not aware of that agreement.

MR. SNOWDEN: Okay.

Q. Are you aware of any additional terms and conditions that were inserted into interconnection agreements around that time addressing power quality issues?

A. I know when issues have arisen in the past, we have modified our interconnection agreements to accommodate resolving those issues.

Q. Thank you. And would you agree that, at least with respect to power quality issues that might be caused by generator interconnections, the Companies have been pretty proactive in trying to identify and address those issues?

A. Yes. Once again, similar to our facility connections requirements.

Q. Okay. Thank you. Mr. Holeman, I'd like to move on to your testimony a little bit, and I'm gonna look -- ask you to look at page 82 of your direct testimony.

A. (John Samuel Holeman, III) I'm there.

Q. Okay. Thank you. And do you see where you say there that, with respect to CPSA and Brattle's modeling, you say on lines 4 and 5 that CPSA and Brattle failed to acknowledge the limitations of storage resources?

A. What line is that?

Q. I'm sorry, that's on line 4 to 5.

A. Yes, I see that.

Q. Okay. Is it fair to say, Mr. Holeman, that your issues with Brattle's modeling that you discuss in your direct testimony relate to how Brattle modeled storage?

A. Ask me that again.

Q. Okay. Is it fair to say that the issues that you discuss in your direct testimony with regard to the modeling that was conducted by Brattle relate to how Brattle modeled storage?

A. I think -- and I think Mr. Roberts can also relay to this question or respond to this question, but I think the concern we have with the modeling of storage is that storage -- you've got to ask the question over what window of time are you gonna storage. Are you gonna charge the storage and can you charge the storage.

These are typically four-hour batteries, so you've got to consider what if I can't charge those batteries. What if the event, whether it's weather, whatever it is, what if the event does not allow me to charge those batteries. What are you gonna do? We've got vast experience with pumped storage, Bad Creek and Jocassee with long duration storage. It's pump storage. It's water instead of chemistry.

And what we're able to do with that capability is we're able to plan it over the week. We typically try to have full pond on Monday -- Monday mornings for the either winter or summer runs. So we're able to make up whatever might happen during the week, we're able to check and adjust with plenty of time to make another plan.

The thing that's often forgot about four-hour batteries is you may not have that time with four-hour batteries. What if the duration of the event is multiple days? And I think we've seen conditions like that in California recently where there's no excess energy to recharge the battery. And don't forget, batteries are energy takers. They are not 100 percent trade-offs charge versus output, they're typically 75 to 85 percent efficient. So you have to have more capability to charge the battery than you're gonna get out and discharge.

And those are the details that we have. I mean, the Commission needs to look no farther than the people sitting at this witness stand to see who's accountable for these types of decisions and these types of management direction. We're ultimately responsible for managing the system from start to finish, because we have the obligation to serve. There's no doubt.

And so we have to consider all of this. We have the ability to take operational experience and plow it into these longer term plans. Like I said before, there's over 200,000 hours in our Carbon Plan. So doesn't it make sense to inform our plan with operational experience that we have in our control centers? I think that's what EPRI, that's what NERC are saying, in terms of where we need to go into the future.

Personally, I think we have the obligation to do that, because we are uniquely charged with our obligation to serve, to deliver for our customers in North Carolina. And, you know, some people may ask why; why are you changing the optimization. My point is why not. We have the unique ability to do that because we cover the whole thing because we are an integrated function, and we have the unique opportunity and I think responsibility to commission our customers to do that.

With the specifics of the question on battery storage, we have the experience to say that doesn't look quite right, and then inform our own plan with what we've experienced in operations.

Q. Mr. Holeman, I --

A. (Sammy Roberts) Can I add?

Q. Sure.

A. I mean, I think one of the things with the Brattle report -- is one of the things we realize with battery storage, we're gonna need battery storage. We're gonna need to be able to shift carbon-free energy from valley areas to peak areas. That's definitely -- so some amount of battery storage is definitely gonna be needed. But what we look at in the Carolinas -- what we think about as system operators is, are we gonna be able to make it through that 2018 extreme cold whether-type week again with respect to you can't be over-reliant on battery storage on that, because it's limited duration.

You can install, you know, a tremendous amount of battery storage. I think this Commission would find it to be cost prohibitive, along with a tremendous amount of other carbon-free energy, whether SMRs or solar or wind, but I think you can become over-reliant on that. And that true test, from a system operations perspective, is, can I make it through that extreme weather week.

I didn't see -- we didn't see where Brattle had properly tested their portfolio with respect to that. They looked at specific years into the future and projected out their forecast, but we didn't see where Brattle had properly tested that type of scenario with their portfolio.

Q. So --

CHAIR MITCHELL: All right. Mr. Snowden, let's pause there. We're gonna take our lunch break. We'll be -- let's go off the record, please. We will be back on the record at 1:45.

(The hearing was adjourned at 12:47 p.m. and set to reconvene at 1:45 p.m. on Wednesday, September 21, 2022.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF WAKE)

I, Joann Bunze, RPR, the officer before whom the foregoing hearing was conducted, do hereby certify that any witnesses whose testimony may appear in the foregoing hearing were duly sworn; that the foregoing proceedings were taken by me to the best of my ability and thereafter reduced to typewritten format under my direction; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this hearing was taken, and further that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 25th day of September, 2022.

JOANN BUNZE, RPR
Notary Public #200707300112