PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Thursday, September 22, 2022

TIME: 1:01 p.m. - 5:00 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: 21

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E X H I B I T S

IDENTIFIED/ADMITTED

Public Staff Metz Exhibit 1..... 27/-

CIGFUR II and III Public Staff ..... 270/-
Thomas, Metz, and Williamson
Panel Direct Cross Examination
Exhibit 1

CIGFUR II and III Public Staff ..... 270/-
Thomas, Metz, and Williamson
Panel Direct Cross Examination
Exhibit 2

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P R O C E E D I N G S

CHAIR MITCHELL: Let's go on the record, please. A few preliminary matters before we get started. Commissioner Brown-Bland is unable to make the hearing today and tomorrow. At this point, I'd ask if anyone objects to her reading the transcript and viewing the YouTube videos for today and tomorrow, as she will have to miss these two days. If anyone objects, please let me know now.

MR. JIRAK: No objections from Duke.

MS. LUHR: No objection from the Public Staff.

MR. QUINN: No objections from NC WARN or Charlotte-Meck NAACP.

MS. CRESS: No objections from CIGFUR II and III.

MR. SNOWDEN: No objection from CPSA.

MR. BURNS: No objection from CCEBA, Madam Chair.

MS. CRALLE JONES: No objections from Appalachian Voices.

MS. FORCE: No objections.

MR. ROUSE: Brad Rouse. I don't have any objection.

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MR. SMITH: No objections from Avangrid.

MS. THOMPSON: No objection from SACE, et al.

MS. GRUNDMANN: Or Walmart, no objections.

MS. JONES: No objection for NCSEA.

MS. BONVECCHIO: No objection from the Environmental Working Group.

MR. DODGE: No objection from NCEMC.

MR. EASON: No objections from Totalenergies Renewable Resources.

MR. BUFFKIN: No objections from Kingfisher Energy or Person County.

MR. TYNAN: No objections from Tech Customers or CUCA.

CHAIR MITCHELL: All right. Before we turn to the Public Staff, I will ask for an update. We continued the hearing until 1:00 today in order to give you-all time. I was informed that there have been settlement discussions among the parties, so I'm gonna ask the Public Staff to provide an update to the Commission on the progress that you-all have made during the past several hours.

MS. LUHR: This is Nadia Luhr with the

Public Staff. So intervening parties who have been working on the settlement worked yesterday late afternoon, evening, and this morning to put together a draft of items that parties could agree on. That part -- that document, I believe, was sent around to Duke and other parties and the Public Staff today around 11:00, 11:30. So I believe everybody is still reviewing that. And if others want to add to that.

CHAIR MITCHELL: I won't call on anybody else at this point in time. Thank you, Ms. Luhr. At this point we have five-plus hours of cross examination time indicated for the Public Staff. I'm assuming that the work y'all did over the past -- yesterday and today means we can eliminate some of this cross examination. Who's willing to give up their cross examination at this point in time? Anybody?

(No response.)

CHAIR MITCHELL: Okay. I'm just curious as to what the discussions have been, then. If there has been consensus achieved and you-all took the time -- the hearing time that we had planned to achieve consensus, where are we? I mean, how

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much -- how much time from Public Staff cross examination -- I've been informed that Duke hasn't participated or just received the benefit of the discussion. So I'm not expecting to hear from Duke that they're gonna give up any of their time.

But is there anyone else that has plans to modify proposed cross examination times? Again, we've continued the hearing until 1:00 today, so I'm hoping that this time has been used productively and it will reflect in the time that we have to spend in the hearing room.

(No response.)

CHAIR MITCHELL: Okay. I'm not hearing anything.

MR. JIRAK: Chair Mitchell, may I?

CHAIR MITCHELL: Please, go ahead.

MR. JIRAK: Let me just say very briefly, we certainly appreciate all the effort that went into developing a proposal. We were not invited to that process. Totally -- that's totally okay for parties to have done that. We received it this morning 11:00 p.m. -- I mean, 11:00 a.m., sorry, and are reviewing it, and we have every intention of responding at the appropriate time.

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And so again, we appreciate it. I think there's a lot of work we have to do to digest it and respond to it. And se we'll continue to try and move the conversation along. I think we just need to continue with the hearing.

I will not, just last thought, if it's okay with you, that we recognize the need to make this process more streamlined and efficient. And in light of the fact that our rebuttal witnesses, I think, will more effectively and efficiently articulate our rebuttal points to the Commission, we are moving forward with the strategy to greatly eliminate our cross time for intervenor witnesses.

And so we're gonna circulate updated estimates at the end of today where we're gonna eliminate most of our planned cross time for intervenor witnesses. If that can then build some momentum behind getting some witnesses dismissed, that would absolutely support that. So we recognize the need to improve efficiency here, and we're gonna try to do our part with our cross times.

CHAIR MITCHELL: All right. Thank you for the update, Mr. Jirak, look forward to updated

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cross -- proposed cross times. Recognize that estimating cross examination times is more of an art than a science, and we are living through that in this hearing, so I understand that. House Bill 951 obligates the Commission to make a decision in this proceeding by December 31st. That's not a you might have a chance to make it or please try your best to make it, it's a make a decision. So the Commission is operating under a statutory deadline and we will not miss that deadline.

In order to do that, we have been very careful and managed and organized with our time to put this agency in a position to do that and allow the parties sufficient opportunity to work together in advance of coming in here to achieve consensus, to achieve understanding, to facilitate understanding of the information that the utility is using.

We've booked an entire month, just about, of this Commission's hearing time to hear from you-all. We have -- we have plenty of other business as some of you-all are very familiar with that we need to get through. We are -- I -- up here every day you-all hear me urging you to use

your time efficiently so that we can manage this proceeding in addition to the other proceedings that we must take care of.

I'm not gonna ask again for you-all to come in here, be prepared, manage your time efficiently, manage this Commission's time efficiently. We have until the end of this month to get this case heard. We -- and if we need to stay until 6:00, 7:00, 8:00 at night, we can do that. If we need to come in at 4:00 in the morning, we can do that. We are going to get this case heard.

From now on, if there's a request for a continuation of the time that we've set aside to hear this case, make productive use of that time. You guys have got to help us get through this case in a timely manner so that we're not having to lean on those who are helping us get through this case to work outside of normal business hours, which is where we are headed very quickly.

With that said, Public Staff, call your witnesses. What's up?

MR. QUINN: Chair Mitchell, I apologize for interrupting. If this is the appropriate time,

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I think a number of intervenors who have witnesses whose presence -- cross examination has been waived could move that prefiled testimony into the record. If it's not the appropriate time, then I will sit back and I will withdraw this inquiry. But my understanding from yesterday is now is, kind of, when we would do that before the Public Staff starts.

CHAIR MITCHELL: I'd like to go ahead and get the Public Staff on the stand. We'll take motions and we'll have testimony copied into the record at the appropriate time. And I'll make sure -- I won't forget and I'll make sure we do it in an orderly way. But thank you for the reminder, Mr. Quinn.

MR. QUINN: Thank you, Chair Mitchell.

CHAIR MITCHELL: Ms. Luhr, you may call your witness.

MS. LUHR: The Public Staff now calls Jeff Thomas, Dustin Metz, and David Williamson to the stand.

CHAIR MITCHELL: All right, gentlemen, good afternoon. Raise your right hands, please. I assume you-all want to be sworn.

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Whereupon,

JEFF THOMAS, DUSTIN METZ, AND DAVID WILLIAMSON,

having first been duly sworn, were examined

and testified as follows:

CHAIR MITCHELL: All right.

DIRECT EXAMINATION BY MS. LUHR:

Q. Mr. Thomas, would you please state your name, business address and current position for the record.

A. (Jeff Thomas) Yes. My name is Jeff Thomas. My business address is 430 North Salisbury Street, Raleigh. And my position is an engineer with the Public Staff.

Q. And on September 2, 2022, did you prepare and cause to be prefiled direct testimony in this docket consisting of 71 pages and one appendix?

A. I did.

Q. Do you have any changes or corrections to your prefiled direct testimony?

A. Yes. I have a minor adjustment to make my testimony on near-term procurement actions. On page 66, line 5 through 67, line 8, I discuss the Public Staff's -- I discuss the Public Staff's concerns with and position on Duke's proposed procurement of the CPRE shortfall as a set-aside in the 2022 solar procurement

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RFP.

We base this conclusion on two factors. That removing the bids that are at or under the avoided cost rate from the weighted average cost calculation could cause the volume adjustment mechanism to procure less solar without actually protecting ratepayers; and 2, the assumption that the CPRE set-aside quantity would consist of both third-party purchases and utility-owned assets, which was not made clear until Duke's September 1, 2022, filing in the solar procurement dockets.

I performed additional analysis on Duke's proposed CPRE set-asides since I filed my testimony, and have concluded that the slightly lower proportion of utility-owned solar assets resulting from Duke's proposal could result in lower cost to ratepayers.

I still believe that the Commission should require Duke to include the CPRE set-aside megawatts when comparing the weighted average cost of the total portfolio of 2022 procurement projects and the solar plan solar reference cost -- the Carbon Plan solar reference cost.

Further, while I believe that the concerns I raise about the additional complexity of implementing

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the CPRE set-aside within the 2022 procurement are still valid, the additional complexities do not outweigh the potential benefits to ratepayers.

Accordingly, on page 69, line 3, the Public Staff would replace "deny" with "approve" resulting in the following revised sentence:

"And approve Duke's request to procure a portion of this capacity through a CPRE set-aside and include those megawatts in determining whether the volumetric adjustment mechanism is triggered in the 2022 solar procurement."

Q. Thank you. And other than that adjustment, if you were asked the same questions today, would your answers be the same?

A. They would.

Q. Did you prepare a summary of your testimony and did you cause to prefiled that summary in the E-100, Sub 179-A docket?

A. Yes.

Q. Thank you. Now, Mr. Metz, would you please state your name, business address, and current position for the record.

A. (Dustin Metz) My name is Dustin Metz. My business address is 430 North Salisbury Street,

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Raleigh, North Carolina. I'm an engineer with the Public Staff.

Q. And on September 2, 2022, did you prepare and cause to be prefiled direct testimony in this docket consisting of 57 pages, one appendix, and one exhibit?

A. Yes, I did.

Q. Do you have any changes or corrections to your prefiled direct testimony?

A. No, I do not.

Q. If you were asked the same questions today, would your answers be the same?

A. Yes, they would.

Q. Did you prepare a summary of your testimony and did you cause to be prefiled that summary in the E-100, Sub 179-A docket?

A. Yes.

Q. Mr. Williamson, would you please state your name, business address, and current position for the record.

A. (David Williamson) Sure. My name is David Williamson, and my business address is 430 North Salisbury Street, Raleigh, North Carolina, and I'm an engineer with the Public Staff.

Q. And on September 2, 2022, did you prepare and

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cause to be prefiled direct testimony in this docket consisting of 46 pages and one appendix?

A. I did.

Q. Do you have any changes or corrections to your prefiled direct testimony?

A. No, I do not.

Q. And if you were asked the same questions today, would your answers be the same?

A. Yes, they would.

Q. Did you prepare a summary of your testimony and did you file that summary in the E-100, Sub 179-A docket?

A. Yes, I did.

MS. LUHR: Chair Mitchell, at this time, I move that the prefiled direct testimony and summaries of testimony of Public Staff witnesses Thomas, Metz, and Williamson be entered into the record as if given orally from the stand, and that Public Staff Metz Exhibit 1 be marked for identification as prefiled.

CHAIR MITCHELL: All right. Hearing no objection, Ms. Luhr, to your motion, it will be allowed.

(Public Staff Metz Exhibit 1 was

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identified as they were marked when prefiled.)

(Whereupon, the prefiled direct testimony and Appendix A of Jeff Thomas, prefiled summary testimony of Jeff Thomas, prefiled direct testimony and Appendix A of Dustin Metz, prefiled summary testimony of Dustin Metz, prefiled direct testimony and Appendix A of David Williamson, and prefiled summary testimony of David Williamson were copied into the record as if given orally from the stand.)

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**BEFORE THE NORTH CAROLINA UTILITIES COMMISSION**

DOCKET NO. E-100, SUB 179

| | | |
|---|---|---|
| In the Matter of | | |
| Duke Energy Progress, LLC, and | ) | **TESTIMONY OF** |
| Duke Energy Carolinas, LLC, | ) | **JEFF THOMAS** |
| 2022 Biennial Integrated Resource | ) | **PUBLIC STAFF –** |
| Plans and Carbon Plan | ) | **NORTH CAROLINA** |
| | ) | **UTILITIES COMMISSION** |

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**Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.**

A. My name is Jeff Thomas. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an engineer with the Energy Division of the Public Staff – North Carolina Utilities Commission.

**Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.**

A. My qualifications and duties are included in Appendix A.

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

A. The purpose of my testimony is to provide the Commission with a summary of my review and investigation of the Proposed Carbon Plan of Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP) (collectively, Duke or the Companies) filed in this docket on May 16, 2022, as well as the initial comments filed by intervenors in this docket, and the direct testimony filed by the Companies on August 19, 2022, including the testimony of Duke witnesses Snider, McMurry, Quinto, and Kalemba (Modeling Witnesses). My testimony is organized based on the July 22, 2022 Issues Report Submitted on Behalf of DEC & DEP (Issues Report), and in accordance with the Commission's July 29, 2022 Order Scheduling Expert Witness Hearing, Requiring Filing of Testimony, and Establishing Discovery Guidelines (Evidentiary Hearing Order).

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**Q. HOW IS YOUR TESTIMONY ORGANIZED?**

A. Consistent with the Issues Report and the Evidentiary Hearing Order, my testimony is divided into the following sections:

I. Modeling Sub-Issues

II. Near-Term Procurement Activity

My testimony also generally covers the topic of Execution Risks, as does the testimony of Public Staff witness Dustin R. Metz.

More specifically, my testimony will address all sub-issues designated under the topic identified as "Modeling – Methodology, assumptions and other modeling issues," including:

a) Whether the Carbon Plan modeling is reasonable for planning purposes;

b) The results of the Public Staff's requested model runs;

c) Modeling assumptions identified by intervenors, including the following issues addressed in turn:

i. Whether a delay in the interim compliance goal[1] is reasonable;

ii. Whether the manual changes made by Duke to override the endogenous selection of optimized resources in EnCompass were reasonable;

[1] The interim compliance goal represents the 70% reduction in carbon dioxide ($CO_2$ or carbon) emissions from 2005 levels.

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iii. Whether the EnCompass optimization period selected by Duke is appropriate;

iv. The appropriateness of annual constraints on solar and wind additions, the first year for economic selection of solar and wind, and cumulative limits on solar plus storage (S+S) and storage;

v. The reasonableness of how S+S is modeled and S+S configurations;

vi. The appropriateness of Duke's natural gas price and supply assumptions and natural gas resource types;

vii. The reasonableness of speculative assumptions regarding the transition to green hydrogen;

viii. The appropriate role of non-commercialized technologies;

ix. Whether Effective Load Carrying Capacity (ELCC) values for natural gas generation and solar generation were appropriate;

x. Whether certain energy resources should be modeled as power purchase agreements (PPAs), and whether all source procurement should be used to procure Carbon Plan resources;

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xi. The appropriateness of resource costs and technological assumptions, including transmission cost adders;

xii. Assumptions regarding the potential for Energy Efficiency (EE), Demand-Side Management (DSM), and behind-the-meter customer generation;

xiii. Whether Duke considered customer programs in its modeling;

xiv. Whether Duke should conduct additional model runs based on a scenario in which the Public Service Commission of South Carolina (PSCSC) denies the incremental costs of the Carbon Plan; and

xv. Whether Duke appropriately considered or evaluated power quality in determining portfolio reliability.

My testimony will also address all sub-issues designated under the topic identified as "Near-Term Procurement Activity—solar, solar+storage, standalone storage, onshore wind, natural gas generation." This includes:

a) the availability and pricing of third-party owned generation; and

b) the reasonableness and prudency of Duke's proposed procurements stated in its near-term supply-side action plan.

My testimony on near-term procurement activities can be found at the end of the modeling section.

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**Q. MR. THOMAS, PLEASE BRIEFLY SUMMARIZE YOUR TESTIMONY.**

A. My testimony supports the Public Staff's Initial Comments and its investigation into Duke's Proposed Carbon Plan. I discuss how the supplemental portfolios filed by Duke along with its direct testimony reflect the modeling revisions recommended by the Public Staff, and recommend that the Public Staff's assumptions be incorporated into the Commission's Carbon Plan. I also address intervenor comments on a wide range of modeling assumptions identified for the evidentiary hearing track and identify where those recommendations were incorporated into Duke's supplemental portfolios. Finally, I discuss Duke's near-term procurement activities associated with an interim compliance date of 2032 and find them generally reasonable and recommend that the Commission approve a revised 2022 Solar Procurement goal of 1,200 MW.

## I. <u>Modeling Sub-Issues</u>

**Q. DOES THE PUBLIC STAFF BELIEVE THE CARBON PLAN MODELING IS REASONABLE FOR PLANNING PURPOSES?**

A. The Public Staff believes that the general approach taken by Duke in the development of its Proposed Carbon Plan – namely, the submittal of multiple pathways and portfolios given substantial uncertainties; the use of sophisticated optimization models to

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determine future capacity expansion plans; input data that reflects historical and projected trends to the extent known; and the identification of a near-term action plan – is reasonable. However, in its Initial Comments the Public Staff identified several modeling methodologies, assumptions, and constraints that it does not believe are reasonable for the development of the Carbon Plan, and which may impact the near-term action plan. Duke's supplemental portfolios submitted with its direct testimony address the majority of the Public Staff's recommendations. The Public Staff recommends that the Commission incorporate the changes reflected in supplemental portfolios 5 and 6 (SP5 and SP6, respectively) into its Carbon Plan.

**Q. PLEASE PROVIDE AN OVERVIEW OF THE SUPPLEMENTAL MODEL RUNS FILED BY DUKE IN ITS AUGUST 19, 2022 DIRECT TESTIMONY.**

A. The results of SP5 and SP6 were provided in Exhibit 1 of Duke's Modeling Testimony. The Public Staff appreciates the Companies' willingness to model these supplemental portfolios based on feedback from the Public Staff and other intervenors. The Public Staff agrees that the modifications made by Duke are responsive to the Public Staff's recommendations. The supplemental portfolios include the following changes recommended by the Public Staff: (1)

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variations on interim compliance (with SP5 achieving the interim compliance goal by 2032, and SP6 by 2034) and availability of small nuclear reactors (SMRs) and offshore wind; (2) optimized S+S modeling and one additional S+S configuration; (3) removal of cumulative limits on battery storage; (4) removal of hydrogen fuel and associated costs; (5) no access to Appalachian gas, limited incremental gas from existing sources, and other natural-gas-related assumptions; and (6) an energy hurdle transfer rate between DEC and DEP imposed during capacity expansion modeling. The results of these supplemental portfolios will be discussed in more detail later in my testimony in the context of the near-term development actions.

The Public Staff wishes to highlight, however, that the supplemental portfolios generally added more solar and batteries than the original portfolios, with significantly less offshore wind. Table 1 below highlights several resources that materially changed as a result of the Public Staff's recommendations. SP5 adds more solar than P2, despite both having a 2032 interim compliance date. SP5 also adds significantly more battery storage than any of the originally filed portfolios.

SP5 and SP6 use no natural gas from the Appalachian region, as recommended by the Public Staff. SP5A and SP6A use this natural gas supply to a limited extent.

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| Table 1 - Cumulative System Resource Additions by 2035 (MW) | | | | |
|---|---|---|---|---|
| **Portfolio – Interim Compliance Year** | **Solar and S+S** | **Batteries (incl S+S)** | **CT** | **Offshore Wind** |
| SP5 – 2032 | 11,800 | 5,500 | 1,200 | 0 |
| SP6 – 2034 | 10,000 | 3,400 | 400 | 0 |
| SP5A – 2032 | 12,100 | 5,200 | 1,100 | 0 |
| SP6A – 2034 | 10,300 | 3,000 | 1,200 | 0 |
| | | | | |
| P1 – 2030 | 13,800 | 4,300 | 1,100 | 800 |
| P2 – 2032 | 10,600 | 2,400 | 1,100 | 1,600 |
| P3 – 2034 | 10,600 | 2,400 | 1,100 | 0 |
| P4 – 2034 | 9,500 | 2,000 | 800 | 800 |

**Q. DID THE PUBLIC STAFF PERFORM ANY ENCOMPASS MODELING IN SUPPORT OF YOUR TESTIMONY?**

A. No. After downloading the EnCompass input data files that were shared with intervenors on August 19, 2022, the Public Staff attempted to import the datasets into EnCompass on August 21, 2022. This import failed. The Public Staff has been diligently working with Anchor Power Solutions, the owner of the EnCompass software, to resolve this import issue, which appears to be due to a problem with cross references between the datasets as well as an extraneous index on one of the resource unit dates. The Public Staff will continue to work to resolve this issue. Given the tight deadlines in this proceeding, the Public Staff reserves the right to request permission from the Commission to file supplemental testimony with the results of EnCompass model runs prior to the evidentiary hearing.

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**Q. TURNING TO THE MODELING SUB-ISSUES, DOES THE PUBLIC STAFF BELIEVE THAT IT IS REASONABLE FOR DUKE TO MODEL A DELAY IN THE INTERIM COMPLIANCE YEAR BEYOND 2030?**

A. Yes. This issue was addressed by multiple intervenors, including the Attorney General's Office (AGO); the joint comments of the North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, Sierra Club, and Natural Resources Defense Council (collectively, CLEAN); Clean Energy Buyer's Association (CEBA); Clean Power Suppliers Association (CPSA); Carolina Clean Energy Business Association (CCEBA); the Environmental Justice Community Action Network and Down East Coal Ash Environmental and Social Justice Coalition (EJCAN and DECAESJC); the Redtailed Hawk Collective and the Robeson County Cooperative for Sustainable Development (RTHC and RCCSD); the City of Asheville and Buncombe County; Person County; and the North Carolina Electric Membership Corporation (NCEMC).[2]

As Duke and many intervenors have highlighted, N.C. Gen. Stat. § 62-110.9(4) provides the Commission with the:

[2] AGO at 7 and Strategen report at 11; CLEAN at 10; CEBA at 4; CPSA at 34; CCEBA at 9; EJCAN and DECAESJC at 21; RTHC and RCCSD at 26; City of Asheville and Buncombe County at 4; NCEMC at 15; Person County at 15.

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> discretion to determine the optimal timing and generation and resource-mix to achieve the least cost path to compliance with the authorized carbon reduction goals, including discretion in achieving the authorized carbon reduction goals by the dates specified in order to allow for implementation of solutions that would have a more significant and material impact on carbon reduction; provided, however, the Commission shall not exceed the dates specified to achieve the authorized carbon reduction goals by more than two years, except in the event the Commission authorizes construction of a nuclear facility or wind energy facility that would require additional time for completion due to technical, legal, logistical, or other factors beyond the control of the electric public utility, or in the event necessary to maintain the adequacy and reliability of the existing grid. In making such determinations, the Utilities Commission shall receive and consider stakeholder input.

As stated in the excerpted language above, the interim compliance goal of a 70% reduction from 2005 emissions can be delayed to 2032 without utilizing the provisions regarding nuclear or offshore wind resources or grid reliability. The Public Staff's September 9, 2022 comments will discuss the Commission's authority to extend the compliance deadlines in S.L. 2021-165 (HB 951), codified as N.C.G.S. § 62-110.9 (Section 110.9), in more detail.

While meeting the interim compliance goal by 2030 should be a priority, the Public Staff also believes it is appropriate for Duke to model multiple portfolios with different interim compliance dates in order to evaluate the costs and generation resource mixes that would result. Without this information, it would be impossible for the Commission to evaluate whether a delay would be in the best interest of ratepayers and whether the adopted Carbon Plan meets statutorily

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mandated "least cost" principles as discussed in the testimony of Public Staff witness McLawhorn. Therefore, the Public Staff believes that it is appropriate to model a delay in this Carbon Plan and future Carbon Plan updates.

**Q. DOES THE PUBLIC STAFF RECOMMEND A DELAY IN INTERIM COMPLIANCE?**

A. The Public Staff is not recommending that the Commission preemptively authorize a delay in meeting the interim compliance goals. The Public Staff supports the carbon reduction goals envisioned in HB 951, but it also must consider the "optimal timing and generation and resource mix" and comply with current law and practice with respect to the least-cost planning for generation. To the extent that a two-year delay allows for more achievable targets for solar, wind, and battery storage interconnections while significantly reducing costs for Duke ratepayers, the Commission should consider exercising the discretion afforded it by HB 951. However, such a determination should be made only after Duke has demonstrated that the interconnection of sufficient resources to meet the interim compliance date by 2030 is not possible, ideally through the results of the 2022 and 2023 Definitive Interconnection System Impact Study (DISIS) cluster studies. A delay beyond two years should not be preemptively authorized in this proceeding, as the Commission

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has not authorized the construction of a nuclear or offshore wind facility that would require additional time to construct, and Duke has not demonstrated that achieving compliance by 2030 or 2032 would result in unacceptable declines in grid reliability. However, delaying until 2032 may allow the Commission to develop a Carbon Plan with lower costs and lower execution risk.

The Public Staff's Initial Comments detailed specific concerns regarding the execution risk and costs associated with Duke's Portfolios 1 through 4 (P1 through P4) and compared the carbon abatement costs of meeting the interim goal by 2030 relative to the Social Cost of Carbon (SCC). In summary, the Public Staff has serious concerns about Duke's ability to interconnect the amount of renewable generation that must be installed by 2030 to meet the targets, particularly given the challenges associated with the required major transmission network upgrades, which will almost certainly involve more than only the 18 specific projects identified in the Red Zone Transmission Expansion Plan (RZTEP). This issue is discussed in more detail in the testimony of Public Staff witness Dustin Metz.

In addition, the Public Staff is concerned that P1 is the most vulnerable to cost overruns related to delayed schedules and material price increases, as it relies heavily on aggressive additions

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of solar and storage, both of which are experiencing substantial near-term cost increases related to global inflation and supply chain issues.[3] The Public Staff also found that the cost per ton of carbon abatement associated with implementing P1 relative to P2, P3, and P4 exceeded the per ton SCC, suggesting that the carbon reduction benefits encapsulated by the SCC would not exceed the incremental costs of 2030 interim compliance under Duke's initial assumptions.[4]

Taken together, the Public Staff believes that significant uncertainty currently exists within each portfolio regarding interconnection ability, resource costs, and operational characteristics of new resource additions. The Commission should direct Duke to take all reasonable steps to streamline its interconnection processes and procure sufficient renewable resources to meet the interim compliance date

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[3] These potential cost increases were discussed during the development of the 2022 Solar Procurement Request for Proposals (RFP). *See* CPSA and CCEBAs Joint Comments on 2022 Solar Procurement Proposal, filed on March 28, 2022, in Docket Nos. E-2, Sub 1297 and E-7, Sub 1268, at 7:

> While future prices cannot be predicted with precision, there are reasons to believe that all-in prices for solar projects may increase rather than decrease in the coming years, similar to other energy and infrastructure projects. The long-term decline in the cost of solar modules has been reversed in the past two years, primarily due to tariffs and supply chain constraints. And while the cost of some solar project components may decrease in coming years, other costs are likely to increase, including materials, labor, and land. It is also impossible to predict how tariffs and supply chain issues will affect pricing in the coming years. The cost of network upgrades, which can be expected to constitute a larger portion of total solar costs going forward, has increased 15-20% per year in recent years and can be expected to continue to do so. Finally, if interest rates increase after 2022 as they are expected to, the cost of financing for all forms of energy infrastructure will rise.

[4] *See* Initial Comments of the Public Staff, at 32.

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by no later than 2032. In support of this requirement, the Public Staff recommended in its Initial Comments that the 2022 Solar Procurement target be increased from 750 MW to between 1,000 and 2,000 MW[5] and worked diligently with Duke to plan a supplemental transmission planning analysis[6] to validate the need for specific projects in its RZTEP, which is discussed in more detail in the testimony of Public Staff witness Metz.[7] As the 2022 DISIS continues and the 2023 DISIS opens, more specific transmission needs and the potential interconnection rate will become more clear.

**Q. DOES THE PUBLIC STAFF BELIEVE THAT THE OUT-OF-MODEL STEPS TAKEN BY DUKE TO OVERRIDE THE ENDOGENOUS SELECTION OF RESOURCES IN ENCOMPASS WERE REASONABLE?**

A. The Public Staff identified these out-of-model steps in its initial comments, as did the AGO, CLEAN, and Tech Customers.[8] The Public Staff and intervenors largely focused on the "battery / combustion turbine (CT) optimization" (Battery Replacement) step,

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[5] *Id*. at 150. Note that in this testimony, the Public Staff is refining its recommended 2022 Solar Procurement target to 1,200 MW.

[6] This supplemental analysis was presented in the August 19, 2022 Direct Testimony of Duke witnesses Dewey S. Roberts II and Maura Farver.

[7] See the Issues Report at 9.

[8] CLEAN: initial comments at 17, Synapse Report at 27; AGO at 15, 24; Strategen report at 33; Tech Customers at 10; Public Staff at 38.

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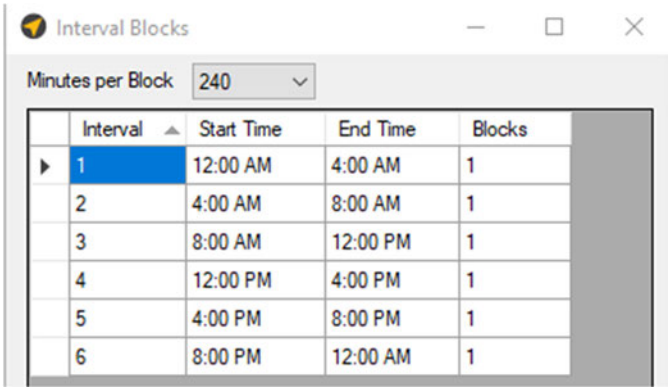
which saw Duke remove 35% of the economically selected battery storage in all portfolios, replacing it with CTs. While Duke discussed the "needle peak" rationale for this process, the Public Staff found the comments of CLEAN and the report by Synapse Energy Economics, Inc. (Synapse Report) to be persuasive. For example, in reviewing the EnCompass scenario settings for Duke's capacity expansion runs, Duke selected a "Typical peak/off-peak day" representation with six daily intervals. This algorithm models area load with two representative days per month: a typical on-peak day, such as a weekday, and a typical off-peak day, such as a weekend or holiday. Each modeled day only includes six intervals, each of which are defined by Duke as four-hour blocks starting at midnight, as seen in the screenshot from EnCompass below.




| Interval | Start Time | End Time | Blocks |
|---|---|---|---|
| 1 | 12:00 AM | 4:00 AM | 1 |
| 2 | 4:00 AM | 8:00 AM | 1 |
| 3 | 8:00 AM | 12:00 PM | 1 |
| 4 | 12:00 PM | 4:00 PM | 1 |
| 5 | 4:00 PM | 8:00 PM | 1 |
| 6 | 8:00 PM | 12:00 AM | 1 |

The end result of this approximation is an aggregated load shape used during capacity expansion model runs that has six four-hour intervals, represented in Figure 1 below by the thick red line (peak

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winter day) and thick black line (average winter day); faint lines represent hourly loads from select days used in the production cost model. Hourly output from wind and solar facilities is similarly aggregated to interval blocks. This representation was confirmed through discussions with Anchor Power Solutions.

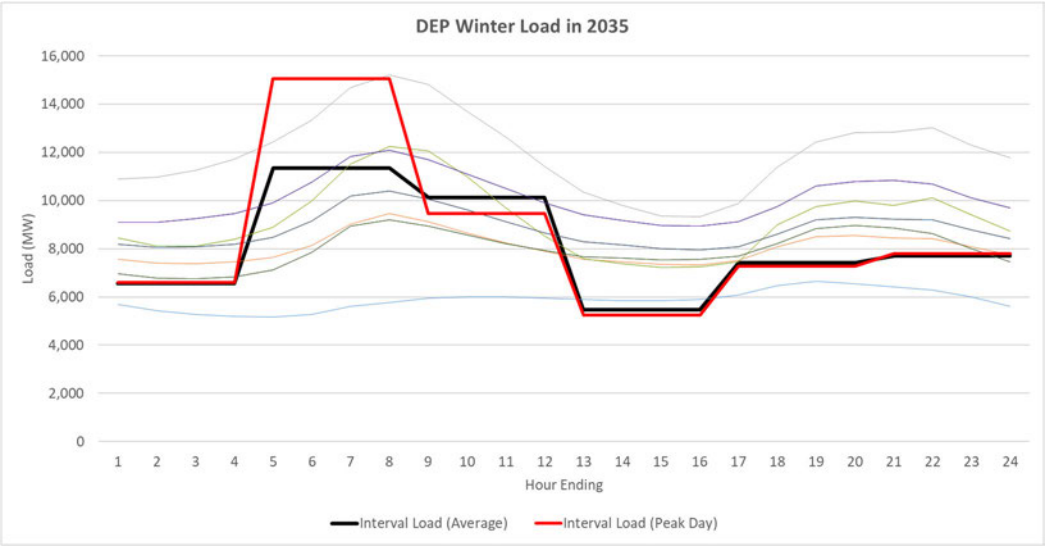


*Figure 1: DEP EnCompass Winter Load in 2035*

As a result, the simplified load shape has a deep, midday valley, as described by Duke in its Proposed Carbon Plan.[9] This load profile would allow batteries to fully charge in a way that may not be possible in actual system operations. However, the morning peak that must be met by the model is similarly broad, four hours long, and is not a "needle" peak that can be easily met by briefly discharging battery

[9] *See* Appendix E at 58.

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storage. Meanwhile, a wide gap exists between the peak and valley of the interval load. As such, Duke's Battery Replacement step may not be reasonable for planning purposes, particularly given the questionable nature of the economic benefits, as described later in my testimony.

Duke performed the Battery Replacement step, in part, to assure "system resource adequacy and reliability when the possibility of extreme weather days that have much longer duration peaks with minimal low load periods to allow for battery charging is taken into account."[10] However, this step was performed prior to the Portfolio Loss of Load Expectation (LOLE) and Resource Adequacy Validation (LOLE Validation) step, where capacity expansion plans were run through the Companies' Strategic Energy Risk Valuation Model (SERVM) to ensure that the LOLE targets were maintained. The Companies found that each portfolio met or exceeded LOLE thresholds and no additional CTs were added.

The Public Staff believes that Duke should have allowed the model to economically select battery storage without replacing 35% of battery capacity with CTs, and if reliability issues were identified during the LOLE Validation step, CTs could be added at that point to

[10] *See* Proposed Carbon Plan, Appendix E, at 59.

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meet LOLE thresholds. This is similar to the process followed by Duke while evaluating alternative plans submitted by intervenors CLEAN and Tech Customers.[11]

**Q. DOES THE BATTERY REPLACEMENT PROCESS RESULT IN COST SAVINGS FOR RATEPAYERS?**

A. In its filing, Duke stated that the Battery Replacement step results in cost savings for ratepayers. For each portfolio, Duke ran two production cost models: (1) a base case with the economically selected battery storage; and (2) a change case with 35% of this battery storage replaced with J-Class CTs. It then compared the difference in production costs for each portfolio with the difference in capital costs of each portfolio, finding that the higher capital costs associated with higher levels of battery capacity in the base case outweighed the production cost savings resulting from lower natural gas consumption. Due to the valid concerns raised by intervenors, the Public Staff revisited this analysis and found that the overall cost savings are relatively minor and are sensitive to assumptions regarding natural gas prices and battery storage capital costs.

Duke provided an analysis of the Present Value of Revenue Requirement (PVRR) savings through 2048 due to the Battery

[11] Modeling Testimony, at 200.

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Replacement step.[12] This figure is shown in the second column of Table 2 below and represents a total portfolio PVRR reduction of between **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, depending on the portfolio.

**Q. DOES THE PUBLIC STAFF BELIEVE THESE RESULTS ARE ROBUST?**

A. No. The Public Staff tested the robustness of these savings estimates under two sensitivities: a 30% reduction to battery storage capital costs, representing the investment tax credit that is now available to standalone energy storage systems; and the use of Henry Hub natural gas prices forecasted in the 2022 Annual Energy Outlook, Low Oil and Gas Supply case.[13] Due to the aforementioned problems loading the supplemental portfolio datasets into EnCompass, this is a post-processing analysis and assumes no changes to unit dispatch. The PVRR savings are dramatically reduced for each portfolio, and in P2 and P3 the replacement of 35% of battery storage with CTs results in a cost increase under these assumptions, as seen in Table 2 below.

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[12] Proposed Carbon Plan, Appendix E, at 59. Duke also provided additional information in response to discovery.

[13] Compared with the Reference case, the Low Oil and Gas Supply case assumes that the estimated ultimate recovery per well for tight oil, tight gas, or shale gas in the United States; the undiscovered resources in Alaska and the offshore Lower 48 states; and rates of technological improvement are all 50% lower.

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**[BEGIN CONFIDENTIAL]**

[redacted]

**[END CONFIDENTIAL]**

**Q. ARE THE COMBUSTION TURBINES FORCED INTO THE MODEL NECESSARY?**

A. It does not appear so. The CTs that are forced into the model to replace batteries and S+S are largely capacity-only resources. Figure 2 below shows the deployment of new CT resources in SP5, along with the capacity factor from the production cost model run. Except for a spike in 2028 after the first CT is constructed, the capacity factor for either class of CTs never reaches above 2% until 2049. Duke acknowledges this in its direct testimony, stating that the CTs are "primarily for system flexibility and back-standing renewables."[15] However, the production cost model runs indicate

[14] The information necessary to complete this analysis was not available to the Public Staff in time to include in direct testimony. These figures will be updated on the stand during the expert witness hearing in this proceeding.

[15] Modeling Testimony, Exhibit 1, at 24.

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that new CTs tend to operate in only one or two months each year, typically only in the winter, and are not regularly called upon to provide system flexibility.

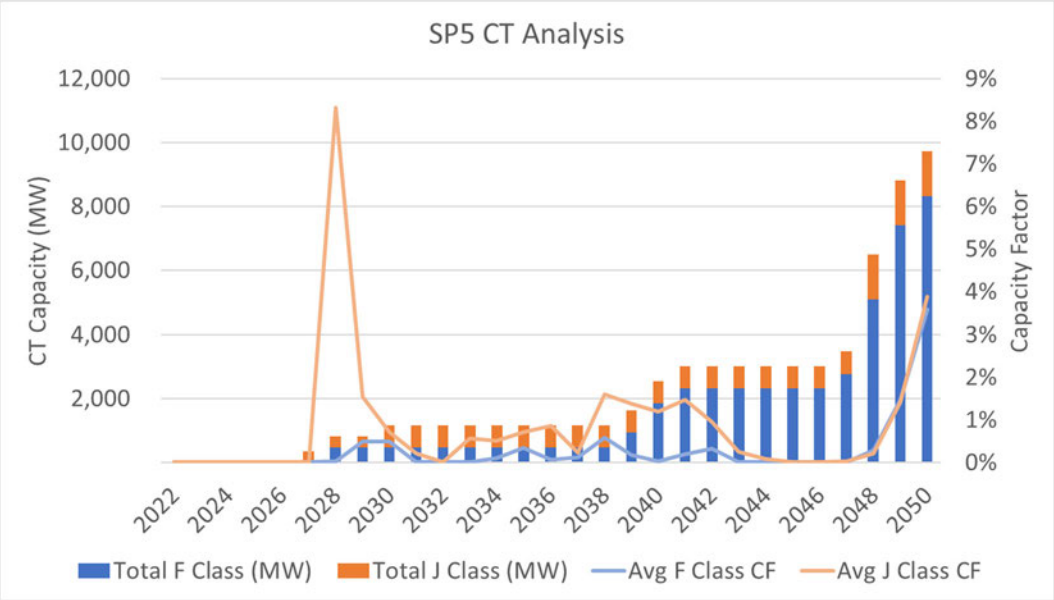


*Figure 2: CT Capacity and Capacity Factors in SP5.*

This is particularly concerning because the reserve margins for both DEC and DEP in SP5 are quite elevated relative to Duke's 17% planning reserve margin, as shown in Figure 3 below. This elevated reserve margin is likely the reason why the economic analysis favored CTs over batteries and S+S in Duke's Battery Replacement step, which compares the reduction in capital costs to the increase in production costs. Because the forced-in CTs generate almost no energy and consume very little natural gas in the model, the expected production cost increase associated with additional CTs is

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very low, tilting the economic analysis towards replacing more batteries and S+S with CTs. If the forced-in CTs were to increase their capacity factors relative to what is modeled, the economic analysis supporting the Battery Replacement step becomes questionable as production costs increase.

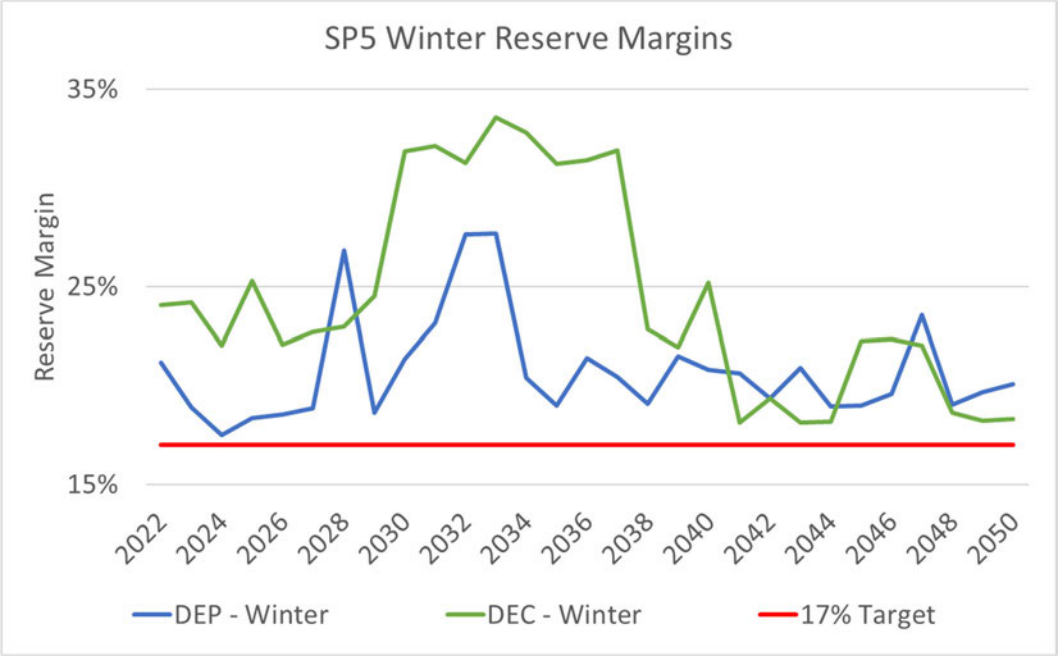


*Figure 3: Annual Winter Reserve Margins in SP5*

Overall, the Public Staff is concerned that the Battery Replacement step: (1) produces minimal ratepayer savings; (2) is not robust to changes in capital costs, fuel prices, or natural gas consumption relative to Duke's assumptions; (3) forces in CTs to serve as essentially capacity-only resources, resulting in elevated reserve margins; and (4) is potentially redundant to the more detailed,

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quantitative LOLE Validation analysis, which was performed after the Battery Replacement step.

**Q. DOES THE PUBLIC STAFF TAKE ISSUE WITH ANY OTHER OUT-OF-MODEL STEPS TAKEN BY DUKE?**

A. The Public Staff is concerned with Duke's out-of-model steps to endogenously select coal retirement dates, as discussed in CLEAN's initial comments.[16] Public Staff witness Metz also discusses this issue in detail in his testimony.

The previously discussed LOLE Validation step appears reasonable and is consistent with the requirements of Section 110.9 regarding system reliability. In its original filing, Duke also forced in certain capacity resources, primarily nuclear, in later model years to reduce Expected Unserved Energy (EUE). As discussed in Duke's Modeling Testimony, this was discovered to be a modeling "bug," and the supplemental portfolios did not have any EUE and therefore required no resources to be forced in.[17]

**Q. DOES THE PUBLIC STAFF BELIEVE THE EIGHT-YEAR OPTIMIZATION PERIOD IS REASONABLE?**

[16] CLEAN Synapse Report, at 28.

[17] Modeling Testimony, at 41.

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A. The issue of the appropriate optimization period over which the EnCompass model solves was raised by Tech Customers, CLEAN, and the Public Staff.[18] As discussed in the Public Staff's Initial Comments, the optimization period is the length of time over which the model optimizes resource selection and dispatch.[19] An eight-year optimization period indicates the model can only "see" costs and system conditions over an eight-year period (with a one-year extension), and is blind to any model inputs beyond the optimization period. The Public Staff agrees with these intervenors that an eight-year optimization horizon is problematic, particularly due to the hydrogen conversion costs in later model years. These costs were excluded from SP5 and SP6, and the Public Staff was satisfied with an eight-year optimization period for purposes of the supplemental portfolios. However, the Gabel Report used a single 28-year optimization period, and the Synapse Report used 15-year optimization periods. Both intervenors were able to complete their model runs by adjusting other settings to reduce run times, such as by increasing the MIP Stop Basis.[20] However, in its Modeling Testimony, Duke did not provide sufficient explanation as to why a

[18] Tech Customers Gabel Report at 49; CLEAN Synapse Report at B-16; Public Staff at 85.

[19] Public Staff Initial Comments at 85.

[20] The MIP Stop Basis is described at length in Duke's Modeling Testimony at 90. Essentially, it is a measure of how accurate the model results are relative to the optimal result.

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relaxed MIP Stop Basis of 0.5% instead of 0.25% is inadequate for determining the least-cost plan while reducing model run times. In response to discovery, Duke stated that the expansion plans using a 0.25% MIP Stop Basis were very similar to those using a 0.5% MIP Stop Basis, although slightly less storage was selected in the near-term. The Public Staff therefore recommends that in future Carbon Plan proceedings the Commission direct Duke to utilize an initial optimization period of no less than 15 years and relax the MIP Stop Basis as necessary and within reason to reduce model run times.

**Q. PLEASE ADDRESS THE MODEL CONSTRAINTS PLACED ON SOLAR AND SOLAR PLUS STORAGE.**

A. In its Proposed Carbon Plan, Duke limited the economic selection of most resources to 2027 at the earliest,[21] including onshore wind, solar, and S+S. Duke also put annual limits on the amount of each resource that could be added to the grid. Duke addresses these limitations at length in its Proposed Carbon Plan Appendix E as well as in its Modeling Testimony beginning on page 155. The Public Staff agrees with Duke that "the question to be addressed is not whether a limitation or constraint is appropriate, but what specific limitation is

[21] Technically, solar is allowed to be economically selected beginning in December 2026, which would place it in service for the subsequent year.

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the most reasonable forecast of the Companies' ability to interconnect solar in the future."[22]

The matter of annual solar interconnections was raised by multiple intervenors as a key issue, including the Public Staff.[23] In its Initial Comments, the Public Staff found that the annual solar interconnection limits used in P2 through P4 were more likely to be achievable than those used in P1, based on historical interconnections and the scope of transmission network upgrades required to interconnect large quantities of new solar.[24] While it is the Public Staff's hope that interconnections will accelerate through the remainder of this decade, the Public Staff still views the base projected annual solar interconnections used by Duke in P2 through P4 and SP5 and SP6 to be reasonable for modeling purposes, and notes that Duke will update future Carbon Plans based on the results from the 2022 Solar Procurement and future DISIS clusters.

The appropriate first year to allow economic selection of solar was raised by both the AGO and CLEAN, who recommended accelerated

[22] Modeling Testimony, at 162.

[23] AGO Strategen Report at 7 and 13; CLEAN Synapse Report at 13; MAREC at 1; CPSA at 9 and 33; CCEBA at 13; Tech Customers at 10, Gabel Report at 32, 34, and 47.

[24] Public Staff at 18.

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deployment of solar in 2026 and 2025, respectively.[25] The Public Staff agrees with Duke that it is unlikely that substantial amounts of solar procured through the 2022 Solar Procurement will come online prior to 2026 due to required transmission upgrades, although it is possible that some competitive projects located outside of the red zone could achieve operation in 2025. While Duke prevented the addition of economically-selected solar prior to 2027, it forced solar into the model between 2023 and 2026, based upon projections of solar currently in the interconnection queue successfully interconnecting and through ongoing programs such as the Competitive Procurement of Renewable Energy (CPRE) and Green Source Advantage (GSA). The amount of forced-in solar is shown in Figure 4 below.

[25] AGO Strategen Report at 7; CLEAN Synapse Report at 14.

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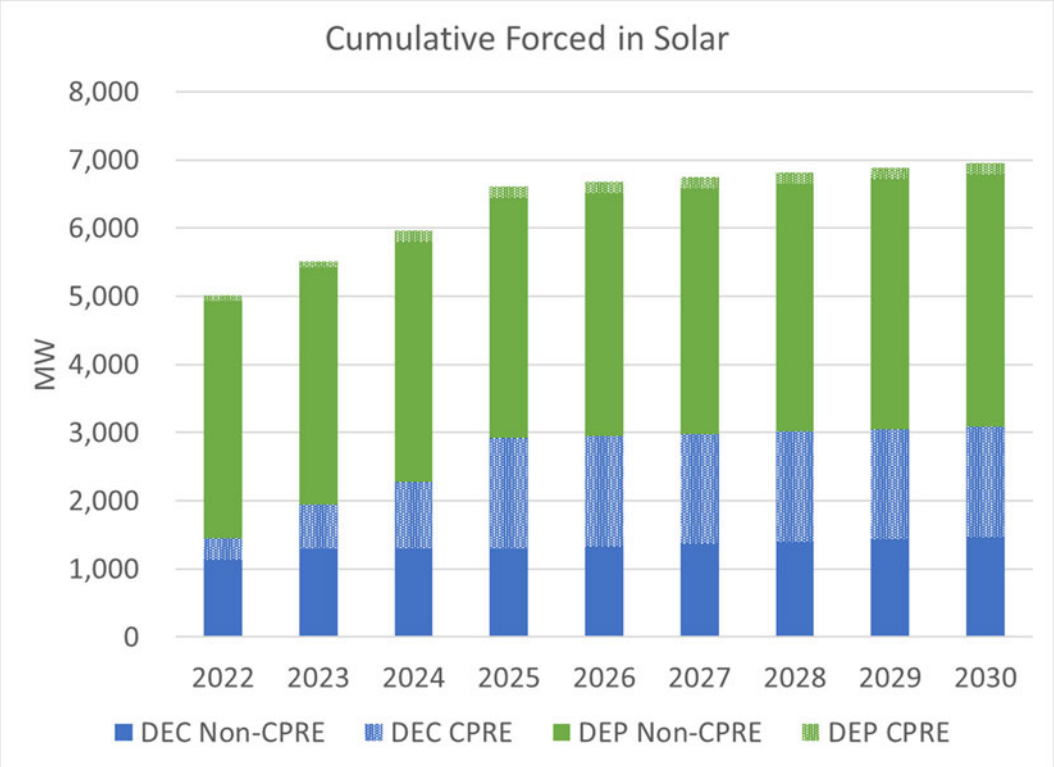


*Figure 4: Cumulative forced-in solar for all portfolios.*

The primary avenue for the procurement of solar capacity this year is the 2022 Solar Procurement Request for Proposals (RFP), which closed in July 2022 and received approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. During the development of the 2022 Solar Procurement RFP, the required in-service date for solar projects was initially set for November 2026, and was later extended to November 2027 due to concerns regarding the ability to meet the 2026 in-service date. Based on the Public Staff's experience with CPRE and understanding of interconnection timelines, inclusive of the required

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network upgrades, the Public Staff expects that the bulk of the solar capacity procured through the 2022 Solar Procurement will come online in late 2026 and 2027. Therefore, the Public Staff finds it reasonable for Duke to force in expected solar capacity from 2022 through 2026 and allow EnCompass to economically select solar beginning in 2027.

**Q. DOES THE PUBLIC STAFF FIND THE CUMULATIVE LIMITS ON SOLAR PLUS STORAGE AND STANDALONE STORAGE RESOURCES TO BE REASONABLE?**

A. No. This issue was raised by the AGO, CLEAN, and the Public Staff.[26] Generally, the Public Staff does not find these cumulative limits to be reasonable for modeling purposes. While the Public Staff recognizes that Duke implemented these limits to reflect the declining ELCC value of such resources, a more appropriate assumption would be to utilize declining ELCC curves that reflect the addition of solar and storage capacity. SP5 and SP6 removed the cumulative limitation on battery storage and extended the ELCC curve in this manner. To the extent possible, Duke should avoid the use of cumulative resource limits that do not reflect known and measurable technical limits.

[26] AGO at 21, Strategen Report at 19; CLEAN Synapse Report at 13; Public Staff at 128.

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**Q. PLEASE ADDRESS THE MODEL CONSTRAINTS PLACED ON WIND RESOURCES.**

A. Concerns around limits placed on the annual interconnections of onshore wind were raised by the AGO, MAREC, CCEBA, and Avangrid,[27] some of whom cited onshore wind projects under development in PJM as justification for an earlier procurement year than Duke's assumption of 2029.[28] Duke placed the following limitations on onshore wind in its modeling: (1) first selectable by 2029; (2) annual limits of 300 MW each in DEC and DEP; and (3) cumulative limits of 600 MW in DEC and 1,200 MW in DEP.[29] The AGO's Strategen Report also claimed that the typical wind project development timeline is two to three years.[30] The Public Staff cannot speak to onshore wind development timelines in PJM. However, there are two onshore wind farms in North Carolina – the operational 208 MW Amazon Wind facility in Perquimans and Pasquotank Counties, and the planned 189 MW Timbermill Wind facility in Chowan County. Both are within PJM's territory.

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[27] AGO Initial Comments at 22 and Strategen Report at 21; MAREC at 2; CCEBA at 45; Avangrid at 10.

[28] AGO Initial Comments at 22, Strategen Report at 20.

[29] Proposed Carbon Plan, Appendix E, at 36.

[30] AGO Initial Comments at 22, Strategen Report at 20.

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The Amazon Wind facility filed its application for a Certificate of Public Convenience and Necessity (CPCN) on January 27, 2011,[31] after significant development work had already been accomplished, including complying with local wind ordinances and submitting an interconnection request to PJM. The facility achieved commercial operation in March 2017, representing a minimum development period of six years, although a significant portion of this time was spent seeking an offtake arrangement and project financing.

The Timbermill Wind facility began seeking local approval for its project in 2016, received its CPCN in May 2022, and is not expected to achieve commercial operation until late 2023.[32] This would represent a minimum development period of seven years.

Given this history and the absence of any wind projects in Duke's interconnection queues,[33] it is unlikely that any onshore wind projects in Duke's territory will be able to achieve operation prior to 2029. In addition, onshore wind imported from PJM or other neighboring areas would require firm point-to-point transmission service and

[31] Docket No. EMP-49, Sub 0.

[32] Docket No. EMP-118, Sub 0.

[33] According to DEC's and DEP's Quarterly Interconnection Queue Performance and Status Reports for the 2nd quarter of 2022, filed August 1, 2022, in Docket No. E-100, Sub 101A, the Companies had 8 kW and 1,072 MW, respectively, of wind projects that were either cancelled or withdrawn. No active wind projects remain in either company's interconnection queue.

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1 would be subject to the appropriate border or wheeling charge.
2 CCEBA also presented additional evidence that onshore wind
3 potential is likely overstated in the Proposed Carbon Plan.

4 Absent convincing evidence that large quantities of onshore wind will
5 be available to Duke earlier than 2029, or that more than 300 MW
6 can be interconnected annually, the Public Staff finds Duke's
7 assumptions with respect to onshore wind reasonable for the
8 development of the Carbon Plan.[34] As the near-term action plan calls
9 for the procurement of 600 MW of onshore wind, the Public Staff
10 expects that if the Commission's Carbon Plan includes onshore
11 wind, Duke will work to procure these resources in accordance with
12 the Commission's interpretation of the statute and be in a position to
13 provide updated assumptions in the 2024 Carbon Plan proceeding.

14 Regarding the availability of offshore wind resources, Duke
15 prevented the selection of offshore wind prior to 2030. Avangrid, the
16 owner of the Kitty Hawk lease area, has stated that it can achieve
17 commercial operation as early as 2029, and has highlighted the
18 advantages of the Kitty Hawk lease over the two recent Carolina
19 Long Bay leases, which are owned by TotalEnergies Renewables

[34] The Public Staff's position that Duke's assumptions with respect to onshore wind are reasonable for the development of the Carbon Plan is based on the assumption that Duke will own those onshore wind resources, consistent with the ownership provisions in Section 110.9(2), unless the Commission determines that the statute allows for the use of PPAs for new generation facilities.

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USA, LLC, and Duke Energy Renewables Wind, LLC, respectively. Duke has acknowledged that placing offshore wind in service by 2029 would require working with a facility that has advanced beyond the leasing phase, which would implicitly involve the Kitty Hawk lease area. While the Public Staff agrees that Duke should seek the least-cost offshore wind resources available to it, there is no guarantee that the more advanced Kitty Hawk offshore wind resource can be secured by Duke, as electric public utilities in Virginia also have stringent carbon reduction goals under the Virginia Clean Economy Act. In addition, as will be discussed further in the Public Staff's September 9, 2022 comments in this docket, Section 110.9(2) requires Duke ownership of new generation facilities for purposes of Carbon Plan compliance. At this time, given the substantial uncertainties regarding offshore wind in the Carolinas as outlined in the Public Staff's Initial Comments, the Public Staff views 2029 as a reasonable first year for offshore wind. Notably, SP5 and SP6 do not economically select offshore wind until the 2040s, which would provide the Commission with additional time relative to a 2029 in-service date to evaluate the least-cost offshore wind resource. The appropriate near-term development actions are discussed in the testimony of Public Staff witness Metz.

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**Q. DOES THE PUBLIC STAFF BELIEVE THAT THE CONFIGURATIONS OF SOLAR PLUS STORAGE RESOURCES SELECTED BY DUKE ARE REASONABLE?**

A. This issue was raised by the AGO, NC WARN, CPSA, CCEBA, and Tech Customers.[35] During its review of the Proposed Carbon Plan, the Public Staff did not raise issues with the limited configurations of S+S resources. Because all models are approximations of reality, and there are essentially infinite configurations of S+S available during project design, some approximations must be made to reduce model complexity. However, intervenors involved in the development of S+S resources have stated that more than two configurations should be included. In its independent modeling, CPSA included four configurations and Tech Customers included three configurations. The Public Staff finds these suggestions reasonable, and notes that SP5 and SP6 include one additional configuration of S+S requested by intervenors.

Ultimately, the Public Staff expects that S+S resources will be competitively procured through annual procurements that are similar to the 2022 Solar Procurement, albeit expanded to procure S+S resources in addition to standalone solar. During these future

[35] AGO at 20, Strategen Report at 15; NC WARN at 13; CPSA at 25; CCEBA at 36; Tech Customers at 10, Gabel Report at 45.

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procurements, the Public Staff expects that a wide variety of S+S configurations will be submitted for evaluation. Assuming that the first S+S procurement will take place during the 2023 DISIS, there should be sufficient time to incorporate common configurations and costs into the 2024 Carbon Plan proceeding if the Commission requires more than three configurations.

As such, the Public Staff recommends that Duke file preliminary 2023 Solar Procurement results in the 2024 Carbon Plan proceeding and explain how its S+S modeling is influenced by the results of the 2023 Solar Procurement. The Public Staff also supports CCEBA and CPSA's recommendation that Duke begin working with stakeholders in advance of the 2023 DISIS to develop appropriate S+S PPA structures that can appropriately value third-party S+S resources,[36] as agreed to by Duke.[37]

**Q. DOES THE PUBLIC STAFF BELIEVE THAT DUKE APPROPRIATELY MODELED SOLAR PLUS STORAGE RESOURCES?**

A. No. This issue was raised by the AGO, CCEBA, CPSA, Tech Customers, and the Public Staff.[38] As summarized in the Public

[36] CCEBA at 45; CPSA at 25.

[37] *See* Modeling Testimony at 72.

[38] AGO at 20, Strategen Report at 14; CCEBA at 36; CPSA at 25; Tech Customers Gabel Report at 9 and 45; Public Staff at 119.

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Staff's Initial Comments, the fixed output profile used by Duke results in a less flexible S+S resource, as the storage dispatch behavior is determined outside of the model and is based on rate periods established in the 2018 avoided cost proceeding. This issue is addressed in SP5 and SP6, and results in significantly increased levels of S+S being selected by the model. For example, SP5 and P2 have the same interim compliance date of 2032. P2 selected approximately 1,100 MW of battery storage by 2030, more than half of which was standalone battery storage. SP5 selected approximately 2,400 MW of battery storage by 2030, less than half of which was standalone battery storage. This result supports the Public Staff's recommendation that Duke should model S+S resources in such a way as to allow EnCompass to optimize the storage component and not use a fixed dispatch profile based on historical avoided cost rate periods.

However, Duke raises legitimate concerns regarding model run times and complexity, with its capacity expansion model runs taking as long as 48 hours.[39] The Public Staff views the longer model run times as a reasonable tradeoff for more accurate S+S resource dispatch in this proceeding. The Public Staff encourages Duke to explore other methodologies for simplifying S+S dispatch or

[39] Modeling Testimony at 152.

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otherwise controlling model run times, as long as it will continue to allow the model to utilize the full benefit of S+S resources. However, using a fixed dispatch profile that is based on historical avoided cost pricing periods is inappropriate for modeling purposes and should not be permitted in the 2024 Carbon Plan Update, as explained in the Public Staff's Initial Comments.[40]

The Public Staff also notes that both CCEBA and CPSA specifically criticized Duke's assumption that S+S resources would have the storage component interconnected on the direct current (DC) side of the inverter (DC-coupled). There are advantages and disadvantages to both AC-coupled and DC-coupled S+S resources, as discussed in detail in these intervenors' comments. The Public Staff agrees that exploring both configurations would be helpful, but again notes that the model contains many simplifying assumptions. For example, the current EnCompass algorithm assumes that a DC-coupled S+S resource can only charge from the solar array, and that an AC-coupled resource can only charge from the grid.[41] This does not reflect the realities of a DC-coupled S+S resource with a bi-directional inverter, nor does it capture the nuances of claiming the

[40] Public Staff Initial Comments, at 121.

[41] Anchor Power Solutions has stated that future EnCompass releases may include the ability for DC-coupled S+S to charge from the grid, but the current version does not have this capability. *See* Modeling Testimony at 154.

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investment tax credit (ITC), which may be rendered moot with the recent passage of the Inflation Reduction Act (IRA) by Congress, which extends ITC eligibility to energy storage without requiring that the energy storage device be charged primarily from the solar resource. However, it may be useful in future Carbon Plans to model both AC-coupled and DC-coupled S+S configurations. The Public Staff believes that the 2023 Solar Procurement, which it expects will include S+S resources, will reveal what configurations are economical for developers, and the 2024 Carbon Plan Update should reflect this variety.

**Q. DOES THE PUBLIC STAFF FIND THE NATURAL GAS PRICES USED IN THE PROPOSED CARBON PLAN TO BE REASONABLE?**

A. Yes. The issue of whether the natural gas price forecast used in the Proposed Carbon Plan was appropriate was raised by the AGO, CLEAN, Carolina Utility Customers Association (CUCA), NC WARN, Tech Customers, and Appalachian Voices (App Voices).[42] Many intervenors highlighted the recent sharp increases in natural gas prices and noted that the price forecasts used by Duke in its Proposed Carbon Plan do not reach the current level of elevated

[42] CUCA at 10; AGO at 16, Strategen Report at 23; CLEAN Synapse Report at A-1; NC WARN at 22; Tech Customers Gabel Report at 24; App Voices at 17.

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natural gas prices, even by 2050. Generally, the Public Staff finds Duke's methodology of using five years of forward market prices, followed by a three-year transition to an average of multiple fundamental forecasts, to be an improvement over past Integrated Resource Plans (IRPs). At this time, the Public Staff is not recommending any changes to natural gas forecasting methodologies.

Intervenors also pointed out that gas price volatility creates asymmetrical risks to ratepayers. The potential PVRR increases from the High Gas scenario are more than double the potential PVRR savings in the Low Gas scenario. The risk of high gas prices and over-reliance on natural gas generation is apparent in Virginia Electric and Power Company's (Dominion) current fuel rider proceeding.[43] Dominion, which has under-recovered its fuel costs by $45 million from its North Carolina jurisdiction, is seeking a fuel deferral balance in Virginia of $1.02 billion.[44] The full recovery of this fuel deferral balance would result in average residential bills

[43] Docket No. E-22, Sub 644.

[44] "SCC Seeks Public Comments on Application of Dominion Energy Virginia to Increase its Fuel Factor." Last accessed on August 16 at: https://www.scc.virginia.gov/newsreleases/release/SCC-Seeks-Comments-on-DEV-Fuel-Factor

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increasing by $24 per month, or 19.8% in Virginia and $19 per month, or 17% in North Carolina.

Dominion has increased its share of natural gas plants over the past several years with the completion of the Bear Garden, Warren County, Brunswick County, and Greensville County combined cycle plants (CCs). Natural gas CCs currently make up 32% of Dominion's installed summer capacity,[45] and Dominion's natural gas fleet supplies approximately 50% of its energy.[46] In contrast, Duke's natural gas CCs make up only 15% of its summer capacity[47] and Duke's natural gas fleet supplies approximately 30% of its energy.[48]

The Public Staff is concerned that significantly increasing Duke's natural gas fleet, particularly its high-capacity factor CCs, creates substantial risk that Duke ratepayers may experience similar rate increases related to future natural gas commodity price spikes as is occurring in Dominion's territory this year. However, the risk of over-reliance on natural gas may be overstated by only reviewing installed

[45] *See* DENC 2021 IRP Update, Appendix 5A.

[46] *See* May 2021 Monthly Fuel Report filed July 19, 2021 in Docket No. E-22, Sub 598 and May 2022 Monthly Fuel Report filed July 19, 2022 in Docket No. E-22, Sub 631.

[47] This figure is calculated for utility-owned generation only. When third-party solar is included, natural gas CCs make up 14% of Duke's total capacity.

[48] *See* June 2021 Monthly Fuel Report filed August 16, 2021 and August 3, 2021 in Docket Nos. E-2, Sub 1270 and E-7, Sub 1248 (respectively), and June 2022 Monthly Fuel Report filed August 5, 2022 and August 8, 2022 in Docket Nos. E-2, Sub 1286 and E-7, Sub 1260 (respectively).

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capacity. While all four of Duke's portfolios maintain roughly the same percentage of natural gas capacity by 2040, they all significantly *decrease* the total amount of natural gas burned annually, as seen in Figure 5 below. Natural gas fuel consumption peaks around 2026 in all portfolios and steadily declines through the remainder of the planning period, reducing Duke ratepayers' exposure to volatile natural gas prices over time. This reduction should mitigate some of the concerns regarding natural gas price volatility in the long run, although it does raise the issue of whether natural gas plants built prior to 2030 will become underutilized, and potentially stranded, in later years as they become primarily capacity resources. Duke's use of an eight-year optimization period caused its models to select natural gas in 2028 and 2029, without considering the stringent carbon reduction targets and higher gas prices in later years.

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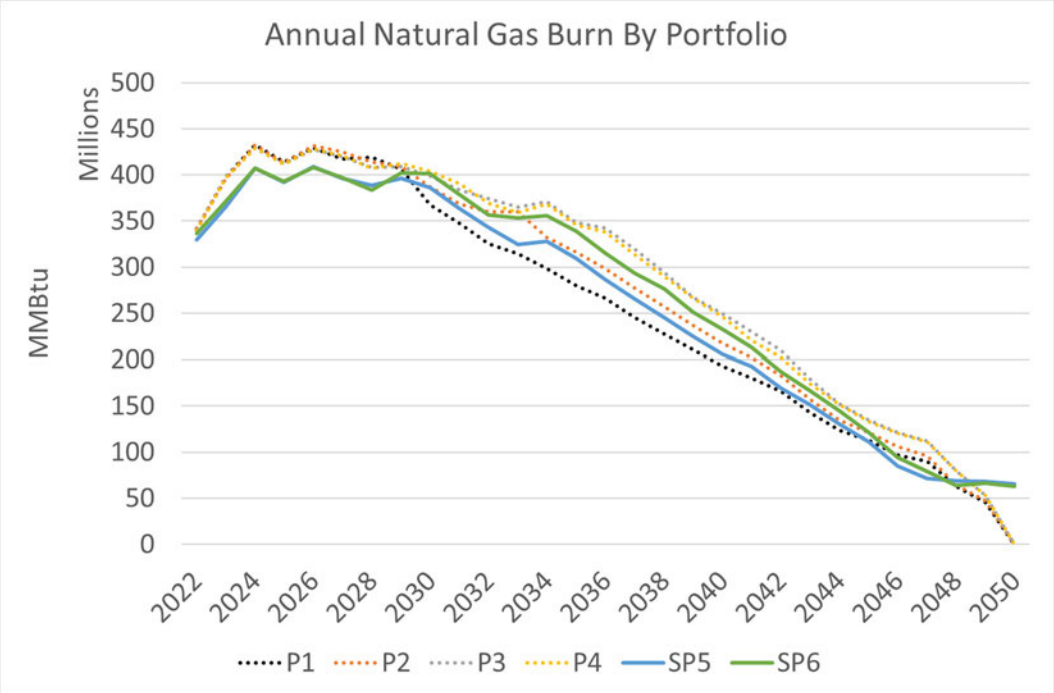


*Figure 5: Annual natural gas burn across Duke portfolios.*

**Q. DOES THE PUBLIC STAFF BELIEVE THAT DUKE SHOULD UPDATE ITS NATURAL GAS PRICES USED IN THE MODEL?**

A. No. The Public Staff believes that the Carbon Plan should utilize the most recent estimates of commodity prices that are available at the time the modeling is performed. Modeling for the Carbon Plan is a complex task, as in the IRP dockets, and typically begins six to nine months in advance of any filing. Fuel price forecasts are typically "locked in" at that time.[49] None of the fundamental forecasts

[49] The Proposed Carbon Plan utilizes fundamental fuel price forecasts from the Energy Information Administration 2021 Annual Energy Outlook, Wood Mackenzie, EVA, and IHS, all of which were developed in 2021. Fundamental fuel forecasts are typically updated only once per year. *See* Appendix E at 39.

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1 anticipated the elevated prices that occurred in 2022, and the forward
2 markets also failed to anticipate this increase.

3 Commodity and generation resource price forecasts can be rendered
4 out of date by global economic events. For example, none of the
5 solar or storage prices in the Proposed Carbon Plan captured the
6 significant cost increases that have recently occurred. The Public
7 Staff recognizes that modeling inputs must be finalized at some
8 point, lest the biennial IRP proceeding devolve into an endless cycle
9 of updating assumptions and re-running the models. The
10 consequences of this reality are tempered by procedural schedules
11 that allow for frequent IRP updates, and a reliance on robust
12 portfolios that cover a range of scenarios.

13 Furthermore, fundamental natural gas price forecasts from the EIA
14 anticipate that average gas prices will fall below $4 per dekatherm
15 (nominal $) between 2023 and 2027, well before natural gas plants
16 are economically selected by the EnCompass model.[50] If these
17 forecasts prove correct, updating the model to reflect the current high
18 prices would have a minor, and likely immaterial, effect on resource
19 selection. The 2024 Carbon Plan Update proceedings will utilize
20 updated natural gas price forecasts, and if future gas prices appear

[50] This is also raised in Duke's Modeling Testimony, at 176.

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elevated, this forecast will be reflected in revised near-term action plans.

Finally, the Public Staff notes that Duke must comply with the provisions of N.C.G.S. § 110.1 and seek a CPCN prior to constructing any natural gas generation. The inclusion of a generation resource in the Commission's Carbon Plan should not be controlling in a CPCN proceeding, and the reasonableness of proposed natural gas plants will be evaluated in detail after the CPCN application is filed, which will include an analysis of the most recent gas price forecasts and market conditions.

**Q. DOES THE PUBLIC STAFF FIND DUKE'S ASSUMPTIONS IN ITS PROPOSED CARBON PLAN REGARDING NATURAL GAS SUPPLY TO BE REASONABLE?**

A. No. This issue was raised by multiple intervenors as well as the Public Staff,[51] and has been a contested issue since the 2020 IRP. The Public Staff reiterates its concerns outlined in its Initial Comments regarding the availability of Appalachian gas to natural gas facilities in North Carolina, and notes that SP5 and SP6 included natural gas supply assumptions recommended by the Public Staff.

[51] CUCA at 8 and 13; CLEAN at 17; AGO at 18, Strategen Report at 25; EJCAN and DECAESJC at 6; RTHC and RCCSD at 7; CPSA at 17; App Voices at 18; Public Staff at 72.

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The Public Staff also notes that the changes modeled in SP5 have resulted in a shift of the location of CC plants. In the original four portfolios, one CC was selected in DEC and one in DEP, both in 2029. In SP5, both CCs are located in DEC's territory, and one CC is delayed until 2030. Even if Appalachian gas is made available to North Carolina via the Mountain Valley Pipeline (MVP) and the MVP Southgate Pipeline, it is unclear whether this gas will have a firm pathway to locations in DEC's territory.

At this time, the Public Staff supports the "No App Gas" supply assumptions used in SP5 and SP6 and expects that the availability of Appalachian gas and its delivered price will be a significant matter of debate in future CPCN proceedings, if any, for natural gas plants.

**Q. DOES THE PUBLIC STAFF FIND DUKE'S NATURAL GAS COMBINED CYCLE CONFIGURATIONS AND OPERABLE LIFE ASSUMPTIONS TO BE REASONABLE?**

A. Yes. This issue was raised by the AGO and the Public Staff.[52] The Public Staff notes that SP5 and SP6 allowed the selection of both the advanced J-Class and the smaller F-Class CTs, which the Public Staff finds reasonable for planning purposes. In SP5 and SP6, only J-Class CCs were selected. Much like S+S configurations, there are

[52] AGO Strategen Report at 27; Public Staff at 135.

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many different specific configurations for a natural gas CC that cannot all be reasonably modeled. The appropriate specific CC configuration will be determined during future CPCN proceedings.

**Q. DOES THE PUBLIC STAFF FIND DUKE'S ASSUMPTIONS REGARDING GREEN HYDROGEN TO BE REASONABLE?**

A. From a methodology perspective, yes; however, the Public Staff believes it is premature to include hydrogen in the model. This issue was raised by multiple intervenors, including the Public Staff.[53] The Public Staff believes that Duke appropriately modeled the inclusion of hydrogen, and appropriately captured the conversion costs for existing gas plants and hydrogen production and transportation costs. However, the Public Staff stands by its Initial Comments and recommends that at this time, hydrogen not be included in the Commission's Carbon Plan. The Public Staff notes that SP5 and SP6 have removed hydrogen entirely from the Carbon Plan modeling, pursuant to the Public Staff's recommendations.[54]

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[53] AGO at 19, Strategen Report at 28; CLEAN Synapse Report at 41, A-3; NC WARN at 18; City of Charlotte at 9; CCEBA at 25; Tech Customers at 12, Gabel Report at 29; Public Staff at 76.

[54] SP5 and SP6 also allowed for the use of carbon offsets to achieve carbon neutrality in 2050.

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**Q. DOES THE PUBLIC STAFF FIND DUKE'S ASSUMPTIONS REGARDING NON-COMMERCIALIZED TECHNOLOGIES TO BE REASONABLE?**

A. Yes. This issue, particularly as it pertains to new nuclear resources modeled in the Proposed Carbon Plan, was raised by multiple intervenors.[55] In its Initial Comments, the Public Staff presented this issue in the context of execution risks. Duke's assumption that new nuclear resources will be available in the future is not unreasonable. It is impossible to know for certain at this time when new nuclear will first become available, or at what price; but the Public Staff believes that SMRs or advanced non-light water reactors will be an available resource at some point in the future. This issue is discussed in more detail in the testimony of Public Staff witness Metz. The carbon reduction targets that have been implemented by other states and the multiple license applications being reviewed by the Nuclear Regulatory Commission support this conclusion. The need for additional nuclear capacity to meet growing electricity demand while reducing carbon emissions has been identified by the

[55] AGO at 24; Strategen Report at 36; NC WARN at 35; CLEAN at 2, 21; City of Charlotte at 10; CCEBA at 21; City of Asheville and Buncombe County at 10; Tech Customers at 3; EWG at 8 and 15.

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1 Intergovernmental Panel on Climate Change,[56] and utilities across
2 the country are planning to incorporate SMRs in their future
3 generation portfolios, with 19 utilities planning to add a combined 90
4 GW of SMRs to the nation's grid by 2050.[57] The Public Staff finds the
5 assumptions used by Duke in its Proposed Carbon Plan to be
6 reasonable for planning purposes and expects that these
7 assumptions will be updated with new information in future Carbon
8 Plan filings. The Public Staff is particularly interested in additional
9 information on when the first SMR might become available, as SP5,
10 SP6, SP5A, and SP6A all call for the first SMR in DEC's territory to
11 be built by mid-2032.

12 **Q. DOES THE PUBLIC STAFF FIND THE ELCC VALUES USED BY**
13 **DUKE TO BE REASONABLE?**

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[56] *See* "Climate Change 2022: Mitigation of Climate Change. Working Group III Contribution to the IPCC Sixth Assessment Report," which states at 3-6:

> Stringent emissions reductions at the level required for 2°C and below are achieved through increased direct electrification of buildings, transport, and industry, resulting in increased electricity generation in all pathways (high confidence). Nearly all electricity in pathways likely limiting warming to 2˚C or below is from low or no carbon technologies, with different shares of nuclear, biomass, non-biomass renewables, and fossil CCS across pathways.

[57] McCarthy, Elizabeth. "Emerging small reactors projected to provide 90 GW of nuclear power to the US grid by 2050: [Nuclear Energy Institute] survey." Utility Dive, August 18, 2022. Accessed at: https://www.utilitydive.com/news/emerging-small-reactors-projected-to-provide-90-gw-of-nuclear-power-to-the/629936/

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A. Yes. The Public Staff has reviewed the results of Duke's ELCC studies for solar and storage in the 2020 IRP proceeding and found them to be reasonable for planning purposes.[58]

**Q. DOES THE PUBLIC STAFF BELIEVE THAT CERTAIN CLEAN ENERGY RESOURCES SHOULD BE MODELED AS PURCHASED POWER?**

A. This issue was raised by multiple intervenors, particularly in the context of offshore wind.[59] While the Public Staff believes that PPAs could facilitate lower-cost and lower-risk resource procurement than the construction of utility-owned assets, Section 110.9(2) requires Duke ownership of new non-solar generation facilities for purposes of Carbon Plan compliance. This will be discussed further in the Public Staff's September 9, 2022 comments in this docket.

However, the Public Staff notes that Duke may have inconsistently applied the utility ownership provisions of Section 110.9(2) with regard to onshore wind resources. Onshore wind is assumed to be utility-owned in DEP's territory and imported through PPAs in DEC's territory, either from PJM, the Midwest, or Texas. This is primarily due to the Mountain Ridge Protection Act, which largely prohibits

[58] *See* Initial Comments of the Public Staff, Docket No. E-100, Sub 165, at 78.

[59] Avangrid at 3; TotalEnergies at 8; NCEMC at 16; Kingfisher at 2 and 5; City of Asheville and Buncombe County at 7; Tech Customers at 5, 18, and 20.

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1 Duke from accessing the higher wind resource potential in DEC's
2 western territory.[60] Duke could have made the modeling choice to
3 simply prohibit the selection of onshore wind in DEC's territory as
4 utility-owned assets could not be constructed, yet Duke made the
5 decision that it is permissible to model these resources as a PPA.

6 **Q. DOES THE PUBLIC STAFF BELIEVE ALL-SOURCE**
7 **PROCUREMENT SHOULD BE UTILIZED TO PROCURE**
8 **RESOURCES IDENTIFIED IN THE APPROVED CARBON PLAN?**

9 A. Yes. This issue was raised by multiple intervenors.[61] The North
10 Carolina Energy Regulatory Process (NERP) released a report on
11 competitive procurements in 2020, finding that "competitive
12 solicitations benefit customers by ensuring the most cost-effective
13 generation resources are selected."[62] The Public Staff agrees and
14 has consistently supported the development of competitive
15 procurement processes for generation resources in North Carolina,
16 as such procurement is consistent with least cost planning principles.
17 In addition, competitive procurement RFPs, such as the ongoing
18 2022 Solar Procurement, provide an opportunity for the Commission

[60] Carbon Plan Appendix J, at 12.

[61] CPSA at 26; CLEAN Synapse Report at 10, A-5; NC WARN at 24; CCEBA at 39; Tech Customers at 10; Gabel Report at 8; Avangrid at 3; TotalEnergies at 8.

[62] The Public Staff also participated in this working group. *See* Competitive Procurement Guidance Document, accessed at https://deq.nc.gov/media/17686/download.

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to compare resource cost assumptions used in the Proposed Carbon Plan model to actual bid prices for these resources.

The Public Staff believes that competitive procurement principles should be used for the procurement of all generation resources identified by the Carbon Plan. However, the carbon reduction goals in Section 110.9 may have changed whether an *all-source* procurement is appropriate, regardless of how the RFP is designed. To wit, the NERP report found that if "future legislation or regulatory changes requires the procurement of additional renewable or low-carbon resources in order to comply with particular policy mandates or directives, resource-specific or otherwise more tailored competitive procurements may be needed."[63] Solar, wind, and battery storage will be needed in great quantities over the next ten to 15 years, and Duke should procure these resources via competitive procurements, but it is not clear if ratepayers would benefit from having a single all-source procurement to meet these goals, or whether resource-specific competitive procurements should be utilized.

In any case, the ongoing 2022 Solar Procurement and the anticipated 2023 procurement for solar and S+S resources will help

[63] *Id*. at 8.

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define how competitive procurements are implemented in the Carolinas and presumably will result in innovative evaluation methods and contract structures in order to move beyond a solar-only procurement. As it has for the 2022 Solar Procurement, the Public Staff intends to be closely involved in the development of future RFPs to ensure that ratepayers benefit from a competitive market and are protected from cost overruns.

**Q. DOES THE PUBLIC STAFF FIND DUKE'S ASSUMPTIONS REGARDING RESOURCE COSTS AND TECHNOLOGICAL CHARACTERISTICS TO BE REASONABLE?**

A. Yes. This issue was raised by multiple intervenors, with the majority of the comments suggesting that Duke underestimated costs for natural gas and nuclear and overestimated costs for solar, wind, and energy storage.[64] In its Initial Comments, the Public Staff did not take issue with any specific resource costs used in Duke's model.[65] The costs for all resources are in a state of flux in the current environment, with global inflation and supply chain constraints causing significant price increases for many technologies,

[64] CPSA at 26; CLEAN Synapse Report at 10, A-5; NC WARN at 24; CCEBA at 39; Tech Customers at 10; Gabel Report at 8; Avangrid at 3; TotalEnergies at 8.

[65] The Public Staff did raise issues with how capital costs were converted into a Real Levelized Fixed Charge Rate and found that the operable life chosen can have an impact on resource selection. No changes were recommended for this proceeding. Public Staff Initial Comments at 132.

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1 particularly those dependent on imported raw materials or
2 components. The Public Staff finds Duke's explanation of the
3 differences between its internal cost estimates and publicly available
4 cost estimates helpful.[66]

5 In addition, the IRA has extended the ITC for renewables and
6 included energy storage as a qualifying resource for the ITC; yet the
7 tax credits are dependent on new factors (such as industry prevailing
8 wages and source of raw materials), can be replaced with a
9 Production Tax Credit (PTC) once energy production begins, and
10 may eventually become technologically neutral. Financing for new
11 nuclear development, including PTCs for nuclear resources, also
12 appears to be included in the legislation, but the capital costs for new
13 nuclear facilities are speculative at best. Incorporating the impacts of
14 the IRA into Duke's models would be complex.

15 Generally, the costs of specific resources are an important factor in
16 determining the least-cost plan in a capacity expansion model.
17 However, given the limited types of low-carbon resources available
18 in the near term and the urgency of the 2030 interim compliance
19 target, model constraints – such as the first available selection year
20 for a resource, the amount that can be interconnected annually and

[66] Modeling Testimony, at 144.

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cumulatively, and annual carbon dioxide limits – are driving much of the new resource selection identified in the near-term action plan. Modeling performed by the Public Staff suggests that resource selection in the near-term is not particularly sensitive to resource prices, particularly for renewables and storage. For this reason and based on its review of the resource cost data used by Duke in developing its Proposed Carbon Plan, the Public Staff generally finds that the resource costs used by Duke in the model are reasonable for planning purposes and based on reasonable assumptions. The Public Staff recommends that pricing information from future RFPs in Duke's territories, particularly for solar and S+S, should be used as inputs to future Carbon Plan updates.

**Q. DOES THE PUBLIC STAFF FIND DUKE'S TRANSMISSION COST ADDERS TO BE REASONABLE?**

A. Yes. This issue was raised by CPSA and CLEAN. CPSA stated that the transmission cost adders were too high, particularly for offshore wind;[67] CLEAN found them to be reasonable.[68] The Public Staff agrees with CLEAN that the transmission cost adders are reasonable for planning purposes, and notes that some specific

[67] CPSA at 29.

[68] CLEAN Exhibit 2, Caspary Report, at 3: "In conclusion, the cost assumptions for transmission expansion associated with new resources in Duke's proposed Carbon Plan appear to be reasonable, with transmission being a small fraction of the total costs for new resources."

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1 transmission costs were derived from historical interconnection
2 studies.

3 **Q. DOES THE PUBLIC STAFF FIND DUKE'S ASSUMPTIONS**
4 **REGARDING THE POTENTIAL FOR EE, DSM, AND CUSTOMER-**
5 **SITED GENERATION TO BE REASONABLE?**

6 A. No. This issue was raised by many intervenors in their initial
7 comments, with most asserting that Duke has underestimated the
8 potential for EE, DSM, and customer-sited resources.[69] Not all
9 intervenors suggested specific targets or programs that should be
10 included in the modeling, instead asserting that Duke needs to do
11 more to expand EE and DSM offerings. The Public Staff, however,
12 found that Duke's estimates for EE were overly aggressive and
13 requested a sensitivity to SP5 and SP6 using a more reasonable
14 forecast.[70] This issue is discussed in more detail in the testimony of
15 Public Staff witness David Williamson.

16 Duke reflects customer-sited generation in its model through its solar
17 net metering forecasts, which are generated external to the
18 EnCompass model, similar to EE. These forecasts do not take into
19 account the proposed tariff changes in Docket No. E-100, Sub 180,

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[69] AGO at 23; Strategen Report at 41; CLEAN at 38; NCEMC at 16; NC Council of Churches at 4; Power Agencies at 3; NC WARN at 29 and 32; Tech Customers at 14, Gabel Report at 37 and 42; App Voices at 20; Environmental Working Group (EWG) at 8.

[70] Public Staff at 69.

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and do not consider other types of behind-the-meter generation, such as standby generators at commercial or industrial sites. The compound annual growth rate Duke assumed for net-metered solar capacity between 2022 and 2035 is 22.6% in DEC and 19.1% in DEP, which is a significant increase from the 2020 IRP, where Duke projected that net-metered solar would increase by 12.2% and 6.6% annually in DEC and DEP, respectively. The Public Staff finds these projections generally reasonable, and notes that no intervenor has presented quantitative evidence that these projections are too low.

While this customer-sited generation does contribute to lowering Duke's demand and energy requirements, it should be noted that Duke's forecasts expect approximately 882 MW of nameplate behind-the-meter solar to be added to its grid by 2035 across residential, commercial, and industrial classes.[71] This represents between only 3 and 4% of the more than 20,000 MW of new generation resources selected in each portfolio by 2035.

In terms of modeling methodologies, it is reasonable to model behind-the-meter generation as a demand-side resource that is exogenous to the model. For one, the decision to deploy behind-the-meter generation is not Duke's to make, but instead depends on

[71] Rooftop solar contributes very little, if any, of its capacity during winter morning peaks.

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each individual customer's decisions. In addition, rooftop solar is generally more expensive and less productive than utility-scale solar, so even if it were modeled as a supply-side resource selectable by EnCompass, the model would maximize utility-scale solar due to its lower costs and higher capacity factors.

While the Public Staff would not object to Duke including customer-sited generation as a supply-side resource in future Carbon Plans, Duke must consider this change holistically and determine whether it would result in material changes to modeling results. Other changes that the Public Staff has recommended, such as the flexible modeling of S+S resources and a longer optimization period, may significantly increase model complexity and computational demand. Adding customer-sited resources as yet another resource to be selected will exacerbate this dilemma and might not result in material changes in model outcomes.

**Q. DOES THE PUBLIC STAFF BELIEVE DUKE ADEQUATELY CONSIDERED DSM, EE, AND CUSTOMER RENEWABLE ENERGY PROGRAMS IN ITS MODELING?**

A. This issue was raised by multiple intervenors and was particularly emphasized by commercial and industrial groups.[72] The appropriate

[72] CIGFUR at 27; CUCA at 15; CEBA at 3; Tech Customers at 14, Gabel Report at 35; Walmart at 14.

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role of new and innovative customer programs in increasing DSM and EE adoption in commercial and industrial customer classes is addressed in more detail in the testimony of Public Staff witness Williamson. The Public Staff encourages Duke to work with stakeholders on developing such programs and forecasts, particularly industry groups that have indicated a desire to assist in carbon reduction goals. Some customer programs envisioned by Section 5 of HB 951 may include dispatchable resources, such as battery storage. To the extent these programs can facilitate large quantities of battery storage, they should be modeled as supply-side resources, similar to the Company's DSM resources.

**Q. DOES THE PUBLIC STAFF BELIEVE DUKE SHOULD PERFORM ADDITIONAL MODELING BASED ON THE REJECTION OF CERTAIN CARBON PLAN COSTS BY THE SOUTH CAROLINA PUBLIC SERVICE COMMISSION?**

A. No, not at this time. While several parties had concerns about the PSCSC denying costs associated with HB 951 compliance,[73] the Proposed Carbon Plan assumes that the historical allocation of system costs between North Carolina and South Carolina ratepayers would continue into the future.[74] While the Public Staff is concerned

[73] CIGFUR at 13; CUCA at 3; CEBA at 7; Tech Customers at 7; Walmart at 10.

[74] Modeling Testimony, at 102.

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about a potential disallowance of costs by the PSCSC, it may be premature at this time to model the impact on system operations and portfolio costs. It is also unclear how this disallowance would be modeled; it may require modifying system topology or assuming independent dispatch of DEC's and DEP's North Carolina and South Carolina territories. Overall, the Public Staff believes Duke's proposal to reflect the PSCSC's determinations in its 2023 IRP in the 2024 Carbon Plan Update is reasonable.[75]

**Q. DOES THE PUBLIC STAFF BELIEVE THAT DUKE APPROPRIATELY CONSIDERED OR EVALUATED POWER QUALITY IN DETERMINING PORTFOLIO RELIABILITY?**

A. This issue was raised by CIGFUR in its initial comments.[76] The Public Staff appreciates the additional perspective on power quality and notes that Duke's reliability analysis considered reserve margins and LOLE but did not consider power quality. To the extent that Duke has the models and capabilities to estimate power quality in various future years based upon the Commission's Carbon Plan, the Public Staff agrees with CIGFUR that this information would provide meaningful insights to stakeholders and the Commission.

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[75] *Id*.

[76] CIGFUR at 10.

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## II. Near-Term Procurement Activity

**Q. TURNING NOW TO THE NEAR-TERM PROCUREMENT ISSUES, PLEASE EXPLAIN THE PUBLIC STAFF'S POSITION.**

A. Duke's Issues Report highlighted several sub-issues under the near-term procurement activity topic. Generally, these sub-issues focus on the appropriateness of the specific near-term procurement resources and quantities requested by Duke in its Proposed Carbon Plan,[77] including the appropriate procurement target for the ongoing 2022 Solar Procurement RFP. The matter of whether competitive procurements should be utilized to procure near-term resources was also raised, which was addressed earlier in my testimony.

**Q. WHAT IS THE PUBLIC STAFF'S POSITION ON THE NEAR-TERM PROCUREMENT ACTIVITIES FOR WHICH DUKE HAS REQUESTED COMMISSION APPROVAL?**

A. The Public Staff recognizes that meeting the carbon reduction targets in HB 951 will require significant investment over the next decade. In its Initial Comments, the Public Staff recommended that Duke submit the results of its supplemental modeling portfolios, and that to "the extent that the near-term activities identified by Duke are

[77] The Issues List filed by Duke included near-term procurement issues from some intervenors as to the appropriate solar interconnection limit, risks of natural gas generation, and whether Duke appropriately evaluated renewable resources. These issues have been addressed in the Modeling section of my testimony.

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consistent with the results from [supplemental modeling], the Commission should approve such activities." I have carefully reviewed the supplemental modeling results and the near-term procurement activities proposed by Duke.

**Q. HAS DUKE MODIFIED THE NEAR-TERM RESOURCES IT IS REQUESTING TO PROCURE BASED ON SUPPLEMENTAL MODELING RESULTS?**

A. No. As stated in the Modeling Testimony and witness Bowman's Exhibit 3, Duke reiterates the same list of resources to be placed in service by the end of 2029 as in its originally filed Proposed Carbon Plan. It is not immediately clear why Duke did not modify its near-term procurement activities based on the supplemental modeling results. Duke states that:

> the results of the supplemental modeling analysis validate the Companies' proposed near-term (2022-2024) actions for supply-side resources presented in Table 3 of the Executive Summary. Informed by this supplemental modeling analysis, the Companies affirm the recommended near-term actions and request that the Commission approve the near-term supply-side development and procurement activities and select the resources presented in Table 3 of Executive Summary under the framework of HB 951.[78]

The Public Staff agrees that the near-term procurement activities are generally validated by the supplemental modeling portfolios.

[78] Modeling Testimony, at 21.

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However, the Public Staff is concerned that near-term procurement activities are insufficient to meet the resource procurement needs identified by the results of SP5 in order to comply with Section 110.9.

**Q. PLEASE EXPLAIN WHAT CHANGES TO THE NEAR-TERM PROCUREMENT ACTIVITIES THE PUBLIC STAFF BELIEVES ARE NECESSARY.**

A. The Public Staff reviewed the original near-term action plan and found that the resource quantities requested generally aligned with the quantities selected in P3 or P4 by 2030. When applying a similar analysis to SP5, which aligns with the Public Staff's recommendation regarding an interim compliance year of 2032 or earlier, significantly more solar and S+S are required over the same time period, as shown in Table 3 below. The Public Staff recommends that the Commission approve the revised, SP5-compliant near-term procurement activities outlined herein.

| **Table 3 – Resources** | **Requested Capacity (MW)** | |
|---|---|---|
| | **As-Filed** | **SP5 Compliant** |
| Solar and S+S | 3,100 | 4,250 |
| Battery Storage (S+S) | 600 | 1,225 |
| Battery Storage (Standalone) | 1,000 | 1,125 |
| Onshore Wind | 600 | 600 |
| Natural Gas CTs | 800 | 800 |
| Natural Gas CCs | 1,200 | 1,200 |

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This revised near-term procurement action plan, if accepted by the Commission, would also necessitate modifications to the 2022 Solar Procurement target capacity, which Duke has requested the Commission separately approve in an order on or before November 1, 2022.[79] In its Petition for Relief, filed on May 16, 2022, Duke requested Commission approval of 750 MW through the 2022 Solar Procurement, which is roughly equal to the amount of solar in its as-filed near-term procurement plan, divided by four years.

**Q. HAS DUKE PROPOSED ANY CHANGES TO THE 2022 SOLAR PROCUREMENT VOLUME?**

A. Yes, the Company does recommend that additional capacity be procured to account for a CPRE under-procurement.[80] Duke will likely not meet the CPRE goal of 1,781 MW of renewable capacity,[81] and expects to fall short by approximately 441 MW. The CPRE shortfall is material because Duke assumed the full CPRE capacity would be procured, and, as a result, forced approximately 1,780 MW of CPRE solar resources into its capacity expansion models, as shown in Figure 6 below.

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[79] *See* DEC-DEP 2022 Solar Procurement Program Final RFP and pro forma PPA Compliance Filing, filed on June 17, 2022, in Docket Nos. E-2, Sub 1297 and E-7, Sub 1268, at 2.

[80] Modeling Testimony, at 77.

[81] The CPRE goal of 2,660 MW set by HB 589 was reduced by transition capacity, as described in N.C.G.S. § 62-110.8(b)(1).

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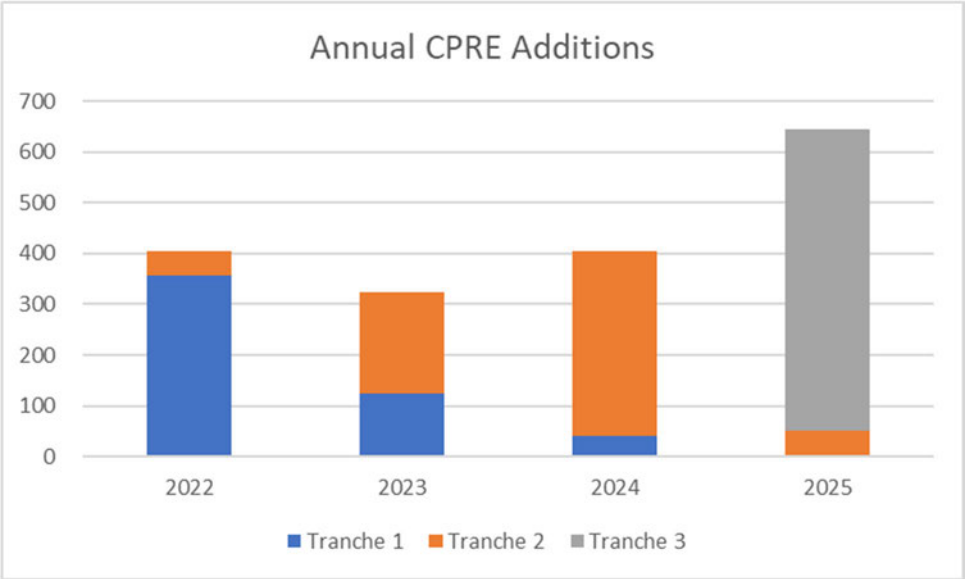


*Figure 6: Annual forced-in additions of CPRE solar, by CPRE Tranche.*

In its direct testimony, Duke recommended that the Commission approve a 2022 Solar Procurement target of 1,200 MW, which would include 750 MW pursuant to the Carbon Plan and the 441 MW CPRE shortfall.[82] Duke states that it would: (1) contract with proposals in the 2022 Solar Procurement to the extent they meet the avoided cost requirements; (2) not count the CPRE shortfall procured towards HB 951 ownership requirements; and (3) not count the CPRE shortfall procured towards the volume adjustment mechanism, which compares the weighted average bid prices received against the levelized cost of solar used in the Carbon Plan models and adjusts

[82] Modeling Testimony, at 74.

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the procurement volume up or down by up to 20%, based on how favorable or unfavorable the comparison is.

**Q. DOES THE PUBLIC STAFF AGREE WITH THE TREATMENT OF THE CPRE SHORTFALL?**

A. No. This methodology concerns the Public Staff for several reasons. First, it is unclear if this process would actually benefit ratepayers, as Duke would essentially be selecting the most competitive projects from the 2022 Solar Procurement and counting them towards CPRE compliance. If the net effect of this process is simply to label the most cost-effective projects that would have otherwise been procured through the 2022 Solar Procurement as "CPRE Projects," ratepayers will not actually realize any savings, as these competitive projects would have likely been selected through the 2022 Solar Procurement even without the addition of the CPRE shortfall.

Next, excluding these projects from the volume adjustment mechanism would increase the weighted average bid price of the remaining 2022 Solar Procurement projects. The purpose of the volume adjustment mechanism is to compare the modeled solar prices to the current solar market, not to a subset of the current solar market after the most cost-effective projects have been removed. Removal of projects selected to fulfill the CPRE shortfall could decrease the total amount of solar capacity procured pursuant to the

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1 Carbon Plan if the volume adjustment mechanism is triggered,
2 without actually affecting the cost of solar procured through the 2022
3 Solar Procurement.

4 Finally, it would be far less complex for the Commission to deem the
5 CPRE Program complete and require the 441 MW shortfall to be
6 procured together with the 2022 Procurement amount, instead of
7 further complicating the 2022 Procurement with a CPRE Program
8 set-aside.[83]

9 **Q. WHAT VOLUME DOES THE PUBLIC STAFF RECOMMEND FOR**
10 **THE 2022 SOLAR PROCUREMENT?**

11 A. In its Initial Comments, the Public Staff recommended a 2022 Solar
12 Procurement volume of 1,000 MW, subject to change based on the
13 results of the supplemental portfolios. Upon review of SP5, dividing
14 the total solar required by 2030 over four years yields approximately
15 1,050 MW that should be procured through the 2022 Solar
16 Procurement, <u>before</u> the 441 MW CPRE shortfall is added. Using
17 SP5 as the baseline and adding the CPRE shortfall yields a 2022
18 Solar Procurement volume of approximately 1,500 MW.

[83] The Public Staff will be providing additional arguments on this issue in its response to Duke's Petition for Approval to Procure CPRE Program Unawarded MW through 2022 Solar Procurement; To Extend CPRE PPA Term; and For Waiver of Certain Provisions of NCUC Rule R8-71, filed in Docket Nos. E-2 Subs 1159 and 1297 and E-7, Subs 1156 and 1268, on September 1, 2022.

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However, there are three caveats to this analysis. First, the CPRE projects that have withdrawn to create the CPRE shortfall have primarily been located in DEC's territory; the Public Staff would therefore expect at least some portion of the 2022 Solar Procurement to be procured in DEC.

In addition, of the 4,250 MW of solar in the near-term procurement activities identified by SP5, only 22%, or 950 MW, is standalone solar; all 441 MW of the CPRE shortfall that was forced into the model is standalone solar. Since the 2022 Solar Procurement is seeking only standalone solar, it is reasonable for the procurement target to be limited by (1) the amount of standalone solar that was forced into the model and not procured, plus (2) the amount economically selected by the model. Adding the CPRE shortfall to the revised 950 MW standalone solar target yields approximately 1,400 MW.

Finally, the Public Staff recognizes that necessary transmission upgrades, including the RZTEP, will take time to implement and have a material effect on annual interconnection rates. Realistically, the 2022 Solar Procurement volume should not be evenly spread over four years to account for the likelihood of a higher interconnection rate in later years.

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Taking all of these factors into account, the Public Staff recommends that in its November order, the Commission approve Duke's request to set a 2022 Solar Procurement Target of 1,200 MW and deny Duke's request to procure a portion of this capacity through a CPRE set-aside. The Public Staff further recommends that the Commission direct Duke to procure a minimum of 440 MW of the 2022 Solar Procurement volume, equivalent to the CPRE shortfall, within DEC's territory.

**Q. DOES THIS RECOMMENDED 2022 SOLAR PROCUREMENT TARGET CONFLICT WITH THE PUBLIC STAFF'S CONCERNS REGARDING EXECUTION RISK?**

A. No. It is true that the Public Staff is skeptical that high levels of annual solar interconnections are achievable in the short term. However, given the large quantity and geographic diversity of projects that have bid into the 2022 Solar Procurement, the Public Staff believes it likely that capacity procured will come online between 2025 and 2027. Some projects may already have completed Facilities Studies or signed Interconnection Agreements, or may have minimal transmission upgrades, and may be able to interconnect in 2025 or early 2026. Further, the 2022 Solar Procurement RFP allows projects to interconnect as late as November 30, 2027. Thus, the 1,200 MW target will likely be spread out over three years, depending

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on project characteristics, costs, and transmission upgrade timelines.

**Q. DOES THE PUBLIC STAFF VIEW THE APPROVAL OF A NEAR-TERM ACTION PLAN AS COMMISSION APPROVAL OF CONSTRUCTION OF GENERATION PLANTS, OR OTHERWISE CONTROLLING IN A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY (CPCN) PROCEEDING?**

A. No. Approval or issuance of a near-term action plan provides clarification on what steps should be taken or are likely to be needed in the planning horizon. Duke will still need to seek CPCN approval for its respective projects <u>or</u> other regulatory approval from local, state, or federal agencies as required.

**Q. DOES THE PUBLIC STAFF VIEW THE SELECTION OF RESOURCES BY THE COMMISSION IN THE ADOPTION OF ITS CARBON PLAN AS AUTHORIZING THE RECOVERY OF COSTS?**

A. No. Ultimately, the review of the reasonableness and prudence of the costs will be decided in a general rate case proceeding, potentially in a multiyear rate plan, and in some cases within the annual fuel rider. The recovery of costs associated with the Carbon Plan is discussed in more detail in the testimony of Public Staff witness Michelle M. Boswell.

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

2 A. Yes, it does.

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## APPENDIX A

## QUALIFICATIONS AND EXPERIENCE

JEFF T. THOMAS, P.E.

I graduated from the University of Illinois Champaign-Urbana in 2009, earning a Bachelor of Science in General Engineering. From 2009 to 2015, I worked in various operations management roles for General Electric, United Technologies Corporation, and Danaher Corporation. I left manufacturing in 2015 to attend North Carolina State University, earning a Master of Science degree in Environmental Engineering. At NC State, I performed cost-benefit analysis evaluating smart grid components, such as solid-state transformers and grid edge devices, at the Future Renewable Energy Electricity Delivery and Management Systems Engineering Research Center. My master's thesis focused on electric power system modeling, capacity expansion planning, linear programming, and the effect of various state and national energy policies on North Carolina's generation portfolio and electricity costs. After obtaining my degree, I joined the Public Staff in November 2017. In my current role, I have investigated and filed testimony in avoided cost proceedings, general rate cases and riders, and CPCN applications. I have also been involved in the implementation of HB 589 programs, competitive resource solicitations, interconnection queue reform, integrated resource planning, customer complaints, and other aspects of utility regulation. I received my Professional Engineering license in North Carolina in April 2020.

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**The Public Staff – North Carolina Utilities Commission**
**Summary of the Testimony of Jeff T. Thomas**
**Docket No. E-100, Sub 179**

The purpose of my testimony is to present the results of my investigation into Duke Energy Carolinas, LLC's (DEC) and Duke Energy Progress, LLC's (DEP) (collectively, Duke) Proposed Carbon Plan. My testimony supports the Public Staff's Initial Comments and its investigation into Duke's Proposed Carbon Plan. Specifically, my testimony addresses the Proposed Carbon Plan modeling and the resultant near-term procurement activities.

My testimony first addresses the interim compliance date and reasonableness of Duke's Proposed Carbon Plan modeling and assumptions. I summarize the Public Staff's position that a delay in interim compliance beyond 2032 has not been justified, and that Duke should make every effort to meet the interim compliance date by no later than 2032, dependent upon interconnection capabilities, resource availability, and transmission constraints. I also summarize the Public Staff's concerns with the execution risk and financial risk associated with the portfolio that reaches interim compliance by 2030 (Portfolio 1). The language of HB 951 provides the Commission with discretion in adopting its Carbon Plan, and the Public Staff believes this discretion requires a balance between carbon reductions, cost, and reliability.

I also discuss how the supplemental portfolios filed by Duke along with its direct testimony reflect the modeling revisions recommended by the Public Staff, including improvements to how solar plus storage resources are modeled, the

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exclusion of Appalachian gas and hydrogen blending, and the removal of overly restrictive model constraints, among other modifications. Based on the supplemental modeling results, I recommend that the Public Staff's assumptions be incorporated into the Commission's Carbon Plan. I also address Duke and intervenor comments on a wide range of modeling assumptions identified for the evidentiary hearing track, and identify where those recommendations were incorporated into Duke's supplemental portfolios or may warrant further consideration.

Finally, I discuss Duke's near-term procurement activities associated with an interim compliance date of 2032 and find them generally reasonable and validated by supplemental modeling results. I recommend that the Commission approve the near-term procurement activities outlined in my testimony, including a revised 2022 Solar Procurement goal of 1,200 MW without a separate carve-out for the Competitive Procurement of Renewable Energy program shortfall.

This concludes my summary.

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**BEFORE THE NORTH CAROLINA UTILITIES COMMISSION**

DOCKET NO. E-100, Sub 179

| | | |
|---|---|---|
| In the Matter of | | |
| Duke Energy Progress, LLC, and | ) | **TESTIMONY OF** |
| Duke Energy Carolinas, LLC, | ) | **DUSTIN R. METZ** |
| 2022 Biennial Integrated Resource | ) | **PUBLIC STAFF –** |
| Plans and Carbon Plan | ) | **NORTH CAROLINA** |
| | ) | **UTILITIES COMMISSION** |

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**Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.**

A. My name is Dustin R. Metz. My business address is 430 North Salisbury Street, Raleigh, North Carolina. I am an engineer in the Electric Section – Operations and Planning of the Public Staff's Energy Division.

**Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.**

A. My qualifications and duties are included in Appendix A.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. The purpose of my testimony is to provide the Commission with a summary of my review and investigation of the Proposed Carbon Plan of Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP) (collectively, Duke or the Companies) filed in this docket on May 16, 2022, as well as the initial comments filed by intervenors in this docket, and the direct testimony filed by the Companies on August 19, 2022. My testimony is organized based on the July 22, 2022 Issues Report Submitted on Behalf of DEC & DEP (Issues Report), and in accordance with the Commission's July 29, 2022 Order Scheduling Expert Witness Hearing, Requiring Filing of Testimony, and Establishing Discovery Guidelines (Evidentiary Hearing Order).

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**Q. HOW IS YOUR TESTIMONY ORGANIZED?**

**A.** Consistent with the Issues Report and the Evidentiary Hearing Order, my testimony is divided into the following sections:

I. Modeling – Carbon Baseline and Accounting Methodologies

II. Modeling – Accounting Requirements for Emissions from New Out-of-State Resources

III. Modeling – Emissions leakages associated with price-induced demand erosion

IV. Coal Unit Retirement Schedule; Securitization

V. Near-Term Development Activity

VI. Work on Existing Resources

VII. Transmission Planning, Proactive Transmission, and RZEP

VIII. Reliability

My testimony also generally covers the topic of Execution Risks, as does the testimony of Public Staff witness Jeff Thomas.

**Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.**

**A.** My testimony reviews and provides the Public Staff's recommendations on the items listed above. My testimony highlights the fact that for some of these items, the Commission should consider not only the modeling results, but also less quantifiable

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factors, including impact on system operations, timing, and implementation. Duke plans to retire significant amounts of coal generation over the next decade, and the Public Staff contends that Duke should present a coal exit strategy to the Commission in future Carbon Plans, identifying additional factors that may need to be considered and potential system impacts. My testimony also discusses that determining a retirement date for each coal plant may require a degree of flexibility as the system transitions, while meeting the carbon reduction targets of S.L. 2021-165 (HB 951), codified as N.C.G.S. § 62-110.9 (Section 110.9).

In addition, Duke proposed a suite of near-term development activities; my testimony outlines the results of my review of Duke's Proposed Carbon Plan and identifies how the supplemental portfolio analysis requested by the Public Staff in its Initial Comments (SP5) differs from or changes these near-term activities. I also update the Commission on the second license renewal process for Duke's nuclear fleet. I conclude my testimony discussing proactive transmission upgrades and the steps the 2023 North Carolina Transmission Planning Collaborative (NCTPC) process must undertake in preparation for the 2023 Solar Procurement.

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## I. Modeling – Carbon Baseline and Accounting Methodologies

**Q. DOES THE PUBLIC STAFF AGREE WITH DUKE'S CALCULATION OF THE CARBON BASELINE?**

A. Yes. The Public Staff had multiple meetings with the North Carolina Department of Environmental Quality and Duke's staff to review historical emissions data and related information prior to Duke's filing of its Proposed Carbon Plan. Based on the Public Staff's review, Duke has correctly accounted for the level of carbon output from its facilities in 2005 for purposes of complying with Section 110.9.

## II. Modeling – Accounting Requirements for Emissions from New Out-of-State Resources

**Q. WHAT IS THE PUBLIC STAFF'S RECOMMENDATION WITH RESPECT TO ACCOUNTING FOR EMISSIONS FROM NEW OUT-OF-STATE RESOURCES?**

A. For modeling purposes, Duke assumed that all new carbon-emitting resources would be located in North Carolina and that its total system carbon emissions would count against the interim and 2050 emissions reduction targets. The Public Staff agrees with this approach.

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With respect to measuring compliance, Section 110.9 provides that "[t]he Utilities Commission shall take all reasonable steps to achieve a seventy percent (70%) reduction in emissions of carbon dioxide (CO2) **emitted in the State** from electric generating facilities owned or operated by electric public utilities from 2005 levels by the year 2030 and carbon neutrality by the year 2050." (emphasis added). Accordingly, the plain language in Section 110.9 appears to indicate that only emissions from in-state (North Carolina) generation sources should be included when calculating interim compliance and carbon neutrality.

However, the Public Staff recognizes the concern associated with locating carbon-emitting resources outside of North Carolina to make an end-run around the spirit of the Carbon Plan. For example, one intervenor noted that although Section 110.9 "refers only to the reduction of carbon dioxide 'emitted in the State' of North Carolina, it would clearly frustrate the intent of the General Assembly if [Section 110.9] simply drove Duke to relocate its carbon emissions to South Carolina."[1] The Public Staff encourages the Commission to exercise oversight in further iterations of the Carbon Plan, IRP and CPCN dockets, and other proceedings to guard against this possibility.

[1] Comments of Clean Power Suppliers Association, Docket No. E-100, Sub 179, at 8 (July 15, 2022).

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**Q. PLEASE CLARIFY AND EXPAND ON HOW CARBON EMISSIONS ARE ACCOUNTED FOR MODELING PURPOSES.**

A. From a modeling standpoint, currently *all* new generation resources built to serve DEC or DEP load have all associated carbon emissions counted toward the carbon compliance targets. While this approach is conservative in nature, it appears to be proper given the uncertainty of where (i.e., in which jurisdiction) new generation resources will be built. This approach reduces speculation regarding future asset locations and reduces modeling complexities. In addition, if Duke were to build new gas-fired generation resources in South Carolina (or any non-North Carolina jurisdiction)[2] and exclude those carbon emissions in the capacity expansion models in future Carbon Plans, the model could select additional natural gas resources merely because of the emission headroom created by locating them out of the state.

## III. <u>Modeling - Emissions leakages associated with price-induced demand erosion</u>

**Q. PLEASE EXPLAIN "PRICE-INDUCED DEMAND EROSION" AND "EMISSIONS LEAKAGE."**

[2] New generation located outside of Duke's North Carolina jurisdictions may be required if it is least-cost or resolves a specific reliability constraint.

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A. Price-induced demand erosion is the loss of energy demand created by increasing energy prices. Emissions leakage occurs when there is an increase in carbon emissions in one geographic area as a result of emissions reductions in a different geographic area. For example, emissions leakage could occur if Duke complies with the emissions reduction targets contained within Section 110.9 for North Carolina by importing (from another jurisdiction) electricity whose generation emits substantial amounts of $CO_2$. Moreover, the two concepts could theoretically intertwine if, to use an extreme example, North Carolina's energy prices were so much higher than other states that the prices caused customers to move out of North Carolina (and thereby cause electric demand in other states to increase).

**Q. DID ANY INTERVENORS COMMENT ON EMISSIONS LEAKAGE AND PRICE-INDUCED DEMAND EROSION RELATED TO SECTION 110.9?**

A. Yes. In its comments filed on July 15, 2022, CIGFUR stated that Duke should "account for carbon leakage associated with the loss of incremental power demand from residential, commercial, and industrial customers leaving the state due to, at least in part, higher electric rates in Duke's service territory."[3]

[3] Comments of CIGFUR II and III, Docket No. E-100, Sub 179, at page 30 (July 15, 2022).

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**Q. COULD THE COSTS OF THE CARBON PLAN DRIVE EMISSIONS LEAKAGE AND PRICE-INDUCE DEMAND EROSION?**

A. Yes, theoretically, if electric rates were to increase significantly in one jurisdiction versus another due to the costs of implementing the Carbon Plan, price-induced demand erosion could directly contribute to emissions leakage. A decrease in energy demand could occur due to a business, or multiple businesses, along with employees and supply chain, relocating to another state that has a relatively lower cost of electric service. As discussed above with respect to emissions leakage, however, the resulting carbon footprint per MWh could remain unchanged or even increase. Therefore, price-induced demand erosion could frustrate Duke's efforts to reduce carbon emissions and increase total carbon emissions.

## IV. <u>Coal Unit Retirement Schedule; Securitization</u>

**Q. HAS THE PUBLIC STAFF REVIEWED DUKE'S PROPOSED COAL UNIT RETIREMENT SCHEDULE?**

A. Yes, however the Public Staff is still reviewing the results of the additional model filed by Duke with its testimony on August 19, 2022.

**Q. WHAT IS DUKE'S CURRENT COAL RETIREMENT SCHEDULE?**

A. Duke's planned coal unit retirement dates are provided in Table 1 of the joint testimony of Duke witnesses Sammy Roberts and Maura Farver (Transmission Panel). Under this schedule, approximately

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60% of Duke's currently active coal generation fleet will be retired prior to 2030. The generation units that will not retire by 2030 are forecasted to have decreasing annual capacity factors (based on production cost modeling results), but in some cases will remain operational for system support purposes, at least until replacement resources can be built. Figure 1 below is a graph of the SP5 model results with coal retirements and annual capacity factors.[4]

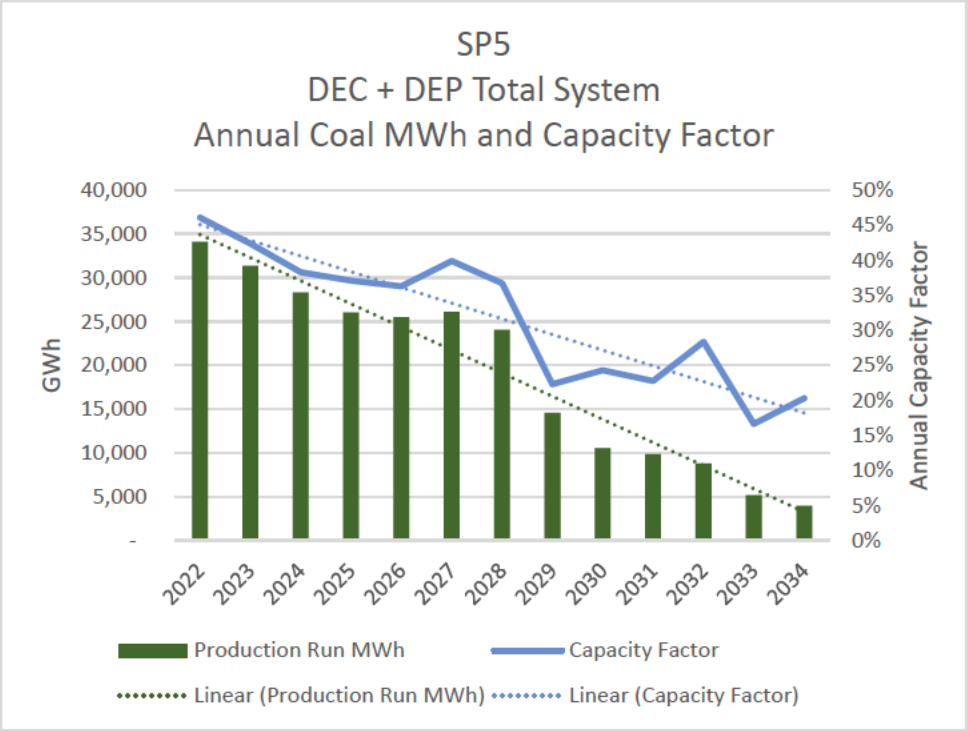


Figure 1: Projected Coal Generation

[4] The retirement year for Roxboro Units 3 and 4 remains uncertain. For purposes of the graph, I used an arbitrary retirement year of 2031, allowing some time for replacement resources to come online. Also noteworthy is the uncertainty around dual fuel optionality impacts on this illustration of the annual capacity factors and production. This may explain the inflection point in 2032 resulting from a very minor difference in the retirement year from a modeling standpoint.

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The coal generation assets that are not retired before 2030 can be used as capacity resources (e.g., Cliffside Unit 6, Belews Creek, and possibly Roxboro Units 3 and 4, pending their firm fuel availability) to meet reserve margin requirements while not being dispatched for daily system needs. They would also be used to account for system anomalies such as loss of another generator during a system peak or unanticipated demand increases resulting from hotter or colder weather than planned. As shown in Figure 2 below, combined cycle facilities (CCs) appear to fill a similar role as the net zero 2050 compliance date approaches.[5]

[5] The Public Staff is still reviewing the supplemental model inputs and results, including unexpected outputs (e.g., natural gas combined cycle annual capacity factors greater than 70%).

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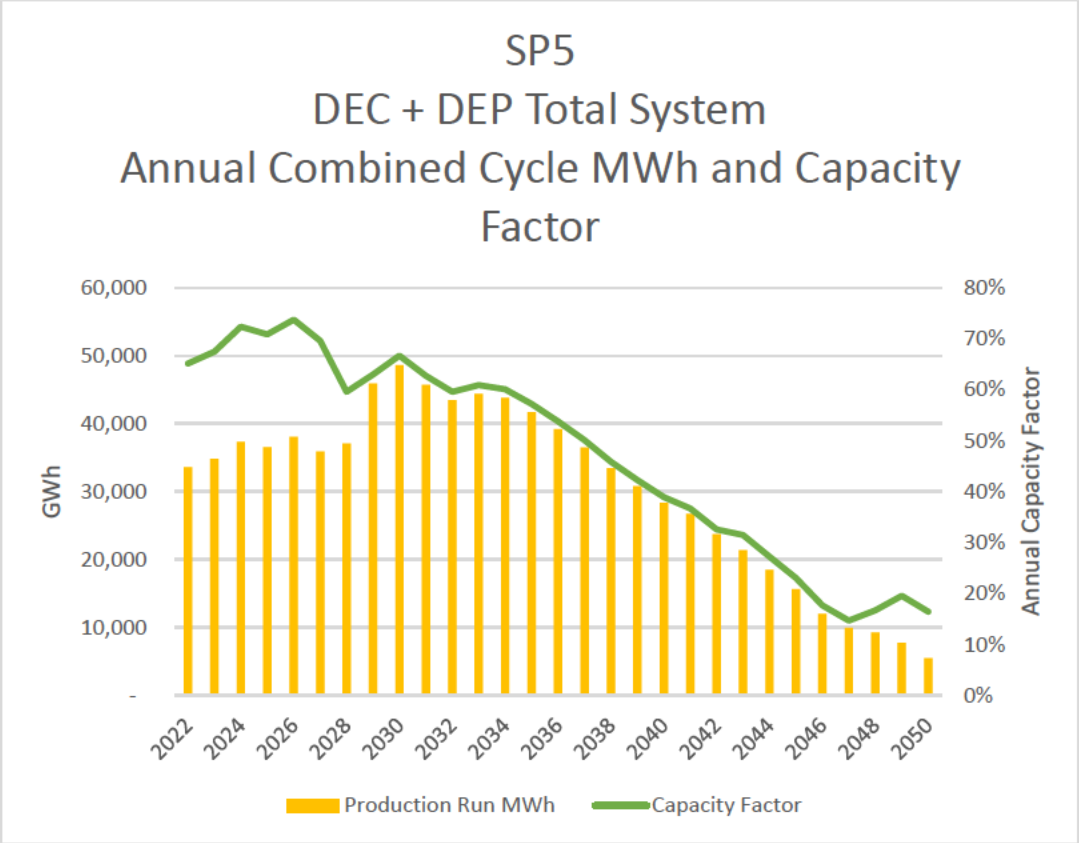


Figure 2: Projected Combined Cycle Generation

**Q. DOES HB 951 ALLOW THE COMMISSION TO IMPLEMENT COAL PLANT SECURITIZATION?**

A. Yes, Section 5 of HB 951 states in part:

> The Utilities Commission is authorized to and shall within 180 days of the effective date of this section, with stakeholder input and participation, establish rules for securitization of costs associated with early retirement of subcritical coal-fired electric generating facilities. With respect to securitization of costs associated with early retirement of subcritical coal-fired electric generating facilities, the Commission shall develop rules to determine costs to be securitized at fifty percent (50%) of the remaining net book value of all subcritical coal-fired electric generating facilities to be retired to achieve the authorized carbon reduction

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> goals set forth in Section 1 of this act, with any remaining non-securitized costs to be recovered through rates. Rules, procedures, obligations, and protections adopted for securitization of costs associated with retirement of subcritical coal-fired generating facilities shall be substantively identical to the provisions of Section 1 of S.L. 2019-244, except with respect to the purposes for which securitization may be used under that section.

Coal unit securitization is discussed in more detail in the testimony of Public Staff witness Michelle M. Boswell.

**Q. IS IT POSSIBLE THAT DUKE COULD RETIRE COAL PLANTS EARLIER THAN INDICATED IN THE JOINT TESTIMONY OF WITNESSES ROBERTS AND FARVER?**

A. Yes, in theory. This was suggested by some intervenors. However, Duke refuted the contention that early retirements could be achieved while still maintaining system reliability.[6]

**Q. WHAT FACTORS SHOULD BE CONSIDERED WHEN ANALYZING THE APPROPRIATENESS OF EARLIER COAL RETIREMENT DATES?**

A. As a general rule, I do not support maintaining the operation of any generating resource beyond its economic life. However, there are

[6] *See, e.g.*, Direct Testimony of Snider, McMurry, Quinto filed in Docket No. E-100, Sub 179 on August 19, 2022, at pages 134-138.

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operational and reliability implications that must be considered and managed as part of any coal exit strategy.[7]

Not all system operational factors can be captured within a model. As a result, the retirement schedule may need to reflect impacts on the transmission system, modifications to the existing transmission system (both upgrades and greenfield facilities), coal inventory and fuel supply, and maintaining system reserves to account for system abnormalities that occur outside of a model (e.g., colder than expected weather, delays in replacement resources coming online, transmission scheduling considerations, etc.). These considerations are but a partial list, but given the transition of the electric system, coupled with technology innovations and aging existing assets, physical and operational limitations must be taken into account. These considerations may also impact the timing of securitization of undepreciated coal plant assets, as discussed in Public Staff witness Boswell's testimony. Duke should continue to update the Commission and stakeholders, on an ongoing basis, of any changes to the current retirement schedule in an annual filing or at a minimum in each biennial Carbon Plan update proceeding.

[7] Duke provided a detailed summary of additional factors that need to be considered for unit retirements in the Direct Testimony of Roberts and Farver filed in Docket No. E-100, Sub 179 on August 19, 2022.

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**Q. DO YOU HAVE CONCERNS IF THE COMMISSION'S CARBON PLAN INCLUDES A DEFINITIVE SCHEDULE FOR THE RETIREMENT OF DUKE'S COAL FLEET?**

A. Yes, but my concern is primarily focused on maintaining operational flexibility and reliability at a reasonable cost. I caution the Commission against ordering an overly prescriptive, inflexible, retirement schedule for the entire coal generation fleet given the multiple factors I listed above, as well as other factors described by Duke's witnesses.[8]

**Q. SHOULD THE NORTH CAROLINA TRANSMISSION PLANNING COLLABORATIVE (NCTPC) EVALUATE COAL RETIREMENT IMPACTS TO THE TRANSMISSION SYSTEM?**

A. Yes. It is my understanding that the NCTPC will evaluate the impacts of plant retirements and new generation additions on the transmission system. This evaluation should aid in identifying potential least cost options for new generation and transmission build-out.

## V. Near-Term Development Activity

**Q. WHAT ARE THE PROPOSED NEAR-TERM ACTIONS IN DUKE'S CARBON PLAN FILING?**

[8] *Id.*

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A. Duke's proposed near-term actions can be found in its Carbon Plan Executive Summary, Table 3. For ease of reference, it is reproduced below:

| Resource | Amount | Proposed Near-Term Actions |
|---|---|---|
| **Proposed Resource Selections: In-Service through 2029** | | |
| Carbon Plan Solar | 3,100 MW | • Begin Public Policy Transmission projects in 2022[6]<br>• Procure 3,100 MW of new solar 2022-2024 with targeted in service in 2026-2028, of which a portion is assumed to include paired storage |
| Battery Storage | 1,600 MW | • Conduct development and begin procurement activities for 1,000 MW stand-alone storage and procure 600 MW storage paired with solar |
| Onshore Wind | 600 MW | • Engage wind development community in preparation for procurement activities<br>• Procure 600 MW in 2023-2024 |
| New CT[1] | 800 MW | • Submit CPCN for 2 CTs totaling 800 MW in 2023 |
| New CC[2] | 1,200 MW | • Submit first CPCN for 1,200 MW in 2023<br>• Evaluate options for additional gas generation pending determination of gas availability |
| **Proposed Resource Development: Options for 70% Interim Target** | | |
| Offshore Wind[3] | 800 MW | • Secure lease<br>• Initiate development and permitting activities for 800 MW[7]<br>• Conduct interconnection study<br>• Initiate preliminary routing, right-of-way acquisition for transmission |
| New Nuclear[4] | 570 MW | • Begin new nuclear early site permit ("ESP") for one site<br>• Begin development activities for the first of two SMR units |
| Pumped Storage Hydro[5] | 1,700 MW | • Conduct feasibility study for 1,700 MW<br>• Develop EPC strategy<br>• Continued development of FERC Application for Bad Creek relicensing |

Note 1: CPCN for two CTs (800 MW) estimated for in-service 2027-2028
Note 2: CPCN for one CC (1,200 MW) estimated for in-service 2027-2028, CPCN for second CC (1,200 MW) will be evaluated for submittal in 2024 with estimated in-service 2030 as fuel supply is determined.
Note 3: Retaining optionality through early development activities, in-service date assumption dependent upon portfolio.
Note 4: New nuclear capacity represents first two SMR units, planned in-service date through 2034.
Note 5: Pumped storage hydro capacity represents second powerhouse at Bad Creek, planned in-service 2033.
Note 6: Projects subject to North Carolina Transmission Planning Collaborative ("NCTPC") approval.
Note 7: Federal regulations require the lessee to submit in the preliminary term of 12 months: (i) a Site Assessment Plan ("SAP"); or ii) a combined SAP and Commercial Operation Plan.

**Q. WHAT IS THE RELATIONSHIP BETWEEN THE RESOURCE SELECTIONS AND THE NEAR-TERM ACTIONS PROPOSED BY DUKE?**

A. As discussed above, Duke's Proposed Carbon Plan proposes near-term actions that will be required to bring the referenced resources online. The resources are divided between those that can be brought online before 2030 and those that can be brought online after. Duke's proposed near-term actions relate to *all* resources, even those that cannot be brought into service in the near future. For example, although Duke will not be able to generate electricity from offshore wind until after 2030, Duke will need to undertake some near-term

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actions now (such as evaluating right-of-way transmission paths) to utilize that resource in the future.

Near-term actions are those that have clearly demonstrated (in a robust modeling scenario) that they are needed to satisfy modeling assumptions and are not heavily dependent upon more detailed information to ensure the reasonableness of the technology, costs, siting of the projects, transmission interconnection, and expected lead time. In other words, these activities can be considered optimal without more extensive analysis.[9]

With respect to those resources that will be placed into service in the year 2030 or later (generally called "Long Lead-Time Resources" by Duke), such items require further analysis, evaluation, permitting, and other regulatory approvals before achieving a satisfactory level of certainty of project viability, timing, and costs. They will need additional study to demonstrate system reliability consistent with least-cost planning. Actions associated with Long Lead-Time Resources should be viewed as potentially economic solutions to aid in the transition of the current electrical system while complying with least-cost planning and system reliability.

[9] This statement does not imply that a CPCN application will not be required or will not be fully and extensively reviewed and evaluated.

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There are three broad categories of Long Lead-Time Resources in Duke's Proposed Carbon Plan: offshore wind; new nuclear; and pumped storage hydro. My testimony analyzes the Long Lead-Time Resources and Duke's proposed near-term actions related to those resources. Public Staff witness Jeff Thomas will address the procurement of near-term resources.

**Q. WILL COMMISSION APPROVAL OF NEAR-TERM RESOURCE DEVELOPMENT ACTIVITIES OBVIATE THE NEED FOR THE COMMISSION TO GRANT A CPCN OR APPROVE COST RECOVERY?**

A. No. While approval of resource development activities in the near-term action plan for both near-term resources and long lead-time resources would clarify what steps the Commission believes Duke should undertake in the planning horizon, Duke will still need to justify why it should be granted a CPCN for each future generation (or transmission) project, as well as obtain regulatory approvals from other state or federal agencies, as required. A review of the reasonableness and prudence of the costs incurred will be determined in the context of a general rate case proceeding, including a multiyear rate plan and, in some cases, in an annual fuel rider proceeding.

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**Q. PLEASE SUMMARIZE DUKE'S REQUEST FOR APPROVAL OF NEAR-TERM DEVELOPMENT ACTIONS IN ITS TESTIMONY FILED ON AUGUST 19, 2022.**

A. The testimony of Duke's Long Lead-Time Resources Panel, comprised of Duke witnesses Regis Repko, Steve Immel, Chris Nolan, and John Holeman, describes Duke's proposal for the near-term development actions related to: (1) pumped storage hydro, in particular upgrades to the Bad Creek facility (Bad Creek II); (2) offshore wind; and (3) new nuclear, in particular small modular reactors (SMRs). All three resources have substantially long lead times and will require near-term actions to be commercially operational in time for Section 110.9 compliance, should the Commission decide that these resources should be a part of the Commission's Carbon Plan.

The Long Lead-Time Resources Panel also discussed non-SMR nuclear technologies and subsequent license renewal (SLR) for Duke's existing nuclear plants. The testimonies of Duke witness Kendal Bowman and the Modeling and Near-Term Actions Panel also impact this topic.

**Q. HAS THE COMPANY PROVIDED A DESCRIPTION OF ITS PLANNED NEAR-TERM ACTIONS FOR LONG LEAD-TIME RESOURCES AS WELL AS THEIR SPECIFIC COSTS?**

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A. Yes. Duke's testimony and discovery responses explain Duke's plans for the near-term actions for its Long Lead-Time Resources. Duke's responses to Public Staff Data Request 7-6 are attached as Metz Exhibit 1. Therein, Duke specifies the activities it envisions as being necessary over the next three years to develop Bad Creek II, SMRs, and offshore wind. These are discussed below.

**Q. DID THE SUPPLEMENTAL PORTFOLIOS SELECT THE LONG LEAD-TIME RESOURCES INCLUDED IN DUKE'S RESOURCE DEVELOPMENT SECTION AS A POTENTIAL LEAST COST PATHWAY?**

A. Yes, noting that the model run results are a function of the model inputs. Project development activities, including scoping studies and locational guidance mapping, generally will help inform future Carbon Plans and identify whether the Long Lead-Time Resources remain least cost when considered through the lens of commercial operation timeframes and viability. The three Long Lead-Time Resources have the potential to take a decade or more to develop from concept phase to commercial operation. Some, particularly SMR deployment and future BOEM offshore wind leases, are also dependent on factors largely outside of Duke's control.

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**Q. SHOULD THE COMMISSION CONSIDER ALLOWING ANY NEAR-TERM RESOURCE DEVELOPMENT ACTIVITIES IN THE 2022 CARBON PLAN?**

A. While the Public Staff is technology agnostic, Section 110.9(4) allows the Commission to consider specific technology resources that may delay the interim carbon emissions limit beyond 2030. Given the modeling results and the long development time for both SMRs and Bad Creek II, it is reasonable for Duke to perform further near-term evaluation to refine the timeline of commercial operation, identify risk factors, and determine more accurate cost estimates. However, North Carolina retail customers should only be responsible for their applicable percentage of reasonable and prudently incurred development costs.

**Bad Creek II**

**Q. CAN YOU DISCUSS PUMPED STORAGE HYDRO?**

A. Pumped storage hydro generates electricity through the flow of water. At the Bad Creek facility, Duke pumps water up to a reservoir and then later releases that water to generate electricity during demand periods.

Although Duke presently utilizes pumped storage hydro, it is properly classified as a Long Lead-Time Resource given the scale of the proposed Bad Creek expansion project. Bad Creek II will require

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further development and analysis in addition to FERC approvals for modification and expansion of the existing pumped hydro facilities.

**Q. HAS DUKE BEGUN DEVELOPMENT WORK AT BAD CREEK II PRIOR TO THE COMMISSION SELECTING IT FOR INCLUSION IN ITS CARBON PLAN?**

A. Based on discovery responses, Duke has already taken some near-term actions related to the Bad Creek II potential resource. First, a Pre-Feasibility Study was completed in January 2020 (before enactment of Section 110.9). Second, a Feasibility Study is presently underway, and it is expected to be completed in the third quarter of 2022. With respect to Bad Creek II, below is a chart[10] that shows Duke's near-term actions and their concomitant costs:

[10] This chart is the entirety of the document embedded in Metz Exhibit 1, at 11.

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**Bad Creek II - Expected early development activities through 2024**

| Activity Description | 2022 | 2023 | 2024 |
|---|---|---|---|
| Pre-Feasibility Study (Completed Jan 2020 $800K) | | | |
| Feasibility Study (Expected completion Q3 2022) | $4M | | |
| BCII FERC License Support | $840K | $1.8M | $2M |
| Geotechnical Studies Phase II | $3M | | |
| DISIS Cluster Deposit | $255K | | |
| Support Project Optimization (Hydraulic Analysis for Pump Turbine) & Tender Design (Model Development & Validating Results) | $1M | $3M | $3M |
| Equipment Solicitation Support | $1.2M | $1.8M | $1.5M |
| EPC Solicitation Support | $150K | $500K | $3.2M |
| Project Management, Engineering, Implementation | $150K | $250K | $350K |
| **Total** | **$10.60M** | **$7.35M** | **$10.05M** |

Based on the table above, Duke plans to spend or has already spent approximately $10.6M for work through 2022 and intends to spend an additional $17.4M through 2024.

**Offshore Wind**

**Q. IS IT REASONABLE FOR DUKE TO PURSUE THE NEAR-TERM ACTIVITIES FOR RESOURCE DEVELOPMENT OF OFF-SHORE WIND?**

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A. Offshore wind development in the United States of the scale proposed by Duke in the Carbon Plan is nascent and is expected to take approximately a decade, at a minimum, to achieve commercial operation, depending on the size of the facility and infrastructure requirements. The supplemental model portfolios SP5 and SP6 did not select offshore wind in the next 10 years, but instead selected it after 2040.[11]

As a result, I recommend that the Commission deny Duke's request to begin near-term resource development activities for offshore wind. The testimony of Public Staff witness Boswell addresses the Public Staff's recommendations concerning accounting treatment of offshore wind costs, including affiliate transfers. I do, however, recommend that Duke re-evaluate the need for offshore wind resources in the 2024 Carbon Plan, at which time the Commission can re-evaluate approval of near-term activities, among other matters.

**Q. WHAT ARE THE PROJECTED COSTS OF DUKE'S NEAR-TERM OFFSHORE WIND DEVELOPMENT ACTIVITIES?**

A. The chart below[12] lists the projected costs for 2022 through 2024:

[11] Duke Modeling Panel, at 69, lines 3-7.

[12] This chart is the entirety of the document embedded in Metz Exhibit 1, at 9.

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| Duke Proposed Three-year annual costs – offshore wind | | | |
|---|---|---|---|
| | **2022** | **2023** | **2024** |
| **Development Expenses** | $2M | $20M | $40M |
| **Radial Transmission** | $5M | $10M | $85M |
| **Network Transmission** | $0 | $15M | $31M |
| **Construction** | $0 | $0 | $0 |
| | | | |
| **Total:** | $7M | $45M | $156M |

These costs exclude the cost of obtaining a lease, which is an additional $155 million.[13]

**Small Modular Reactors**

**Q. PLEASE DISCUSS SMALL NUCLEAR REACTORS**

A. An SMR is described by its name. They are physically smaller, generate less electricity than traditional nuclear plants, are modular in the sense that much of the construction can be completed offsite, and rely on nuclear reactors to generate electricity.

**Q. DID THE PUBLIC STAFF REVIEW THE SMR DEVELOPMENT COSTS PROPOSED BY DUKE?**

[13] https://www.boem.gov/renewable-energy/state-activities/carolina-long-bay.

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A. Yes. Metz Exhibit 1[14] presents the steps Duke plans to take over the next three years to develop SMRs. Duke's estimated costs as set forth in Metz Exhibit 1, for the years 2023 and 2024, total $37 million. The testimony of Duke's Long Lead-Time Resources Panel regarding the anticipated actions and forecasted costs related to new nuclear resources provides for an estimated cost of $63.5M for the years 2023-2024 with a total of $72 million for 2022 through 2024[15] at page 35, line 5, as follows:

**Table 2: New Nuclear Near-Term Development Activities**

| Activity Description | 2022 | 2023 | 2024 | Total |
|---|---|---|---|---|
| Begin new nuclear Early Site Permit (ESP) development<br>• Administrative and Financial Information<br>• Site Safety Analysis Report (SSAR)<br>• Plant Parameter Envelope<br>• Environmental Report<br>• Limited Work Authorization<br>• Emergency Planning<br>• Departures and Exemption Requests | 5,000,000 | 25,000,000 | 25,000,000 | **55,000,000** |
| Begin development activities for the first of two SMR units<br>• Siting Assessment & Selection<br>• Technology Assessment & Selection<br>• Develop COL Application | 3,500,000 | 3,500,000 | 10,000,000 | **17,000,000** |
| **Total** | **8,500,000** | **28,500,000** | **35,000,000** | **72,000,000** |

**Q. ARE YOU DISPUTING THE COSTS AND REQUIRED ACTIVITIES THAT DUKE HAS STATED?**

A. No, but I do not have the means to measure or evaluate Duke's listed activities. In any case, these costs that Duke has incurred or expects

[14] Metz Exhibit 1, at 5-7. While Metz Exhibit 1 is labeled as confidential, the Public Staff has confirmed with Duke that it is no longer confidential and can be used in the public version of the Public Staff's testimony.

[15] Long Lead-Time Resources Testimony at 35, It is not clear whether these costs exclude AFUDC (or its equivalent).

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to incur are more appropriately investigated for reasonableness and prudence during a general rate case at the time Duke seeks cost recovery. At that time, the Public Staff will recommend an appropriate allocation of reasonable and prudent costs to North Carolina retail customers.

**Q. MULTIPLE INTERVENORS HAVE EXPRESSED SKEPTICISM OF NEW NUCLEAR TECHNOLOGIES. SHOULD THE COMMISSION CONSIDER NEW NUCLEAR TECHNOLOGIES?**

A. As stated previously, the Public Staff is technology agnostic in terms of resource selection. Some intervenors do not distinguish the different forms of nuclear power technologies when raising their various concerns. I discuss three of the technologies below.

The first technology is traditional large-scale nuclear power plants with a nameplate capacity of approximately 1,000 MW or larger. Construction of Westinghouse AP-1000s in the southeast United States has proven to be logistically problematic and has resulted in significant cost overruns, and even cancellations. At least six AP-1000s (or the appropriate relevant nomenclature) have been in various stages of construction over the last 10 to 15 years across the globe, with four of them either commercially operational or very close to it. Other large-scale nuclear reactors that are not a Westinghouse design have been built or are under construction. Areva/Framatone

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also has six of their EPR (Evolutionary Power Reactor) reactors either commercially online or in some stage of construction or testing. Globally, these reactors have experienced some of the same issues experienced by Westinghouse AP-1000s around timing, logistics, and cost over-runs, as experienced in Europe and the United States. In addition, there are other larger scale nuclear power plants across the globe that are actively being planned and constructed by other manufacturers.

The second technology is small modular reactors (SMRs). At a very high level, SMRs are similar to existing nuclear reactors, but at a much smaller scale in terms of size, cost, and construction time due to their modular characteristics. The size and modularity provide for more flexibility in terms of siting and land requirements. Some discrete differences exist in each manufacturer's design, which do not directly compare to traditional boiling and pressurized water reactors.

The third technology is advanced reactors, other than SMRs, which do not use water as the primary coolant, but use either gas or molten salt (or equivalent) and operate at higher temperatures. The Long Lead-Time Resources Panel describes the differences between

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SMRs and advanced reactors.[16] Duke proposes to utilize advanced reactors no earlier than 2038.[17]

Each of the three types of nuclear technologies are at different points of regulatory approval, project development, design, and operability. In my opinion, it is not appropriate to compare one technology type or design (including the technology's challenges or potential challenges) to that of another given the complexity and discrete differences.

## VI. Work on Existing Resources

**Q. IS IT REASONABLE FOR DUKE TO PURSUE EXPANDING THE FLEXIBILITY OF ITS EXISTING GAS FLEET?**

A. Yes, to the extent that Duke has identified a targeted need on a project-by-project basis (plant-specific or regional). If flexible expansion projects prove to be least cost for compliance with Section 110.9 and improve or maintain system operability requirements, it is reasonable for Duke to pursue the projects as needed. Future Carbon Plans will likely further evaluate ramping and start/stop constraints, given the changes in the generation portfolio and load shapes, and will also identify discrete flexibility requirements.

[16] See p. 26-27.

[17] Direct Testimony of Duke Witnesses Repko, Immel, Nolan, and Pompee filed E-100, Sub 179 on August 19, 2022, at page 27, lines 5-6.

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Therefore, the capital investments required to increase the flexibility of Duke's existing fleet of natural gas resources should demonstrate through cost-benefit analyses that the additional benefits of flexibility justify the costs, and that system flexibility cannot be achieved through alternative means.

**Q. IS THE SAME TYPE OF ANALYSIS REQUIRED TO EVALUATE EXPANDING THE FLEXIBILITY OF EXISTING NATURAL GAS PLANTS AS IS REQUIRED TO EVALUATE SLR FOR DUKE'S NUCLEAR FLEET?**

A. No. It would be inappropriate to compare the scope of work for these two actions. Duke's current nuclear licenses are scheduled to expire over the coming decades. Duke intends to pursue subsequent license renewal (SLR) and seek an additional 20-year operating life for its nuclear generation. It is impossible to determine the prudence of increasing the flexibility of the existing natural gas fleet or proceeding with SLR or any other generation asset requirements at this time.

**Q. DO YOU OPPOSE THE COMPANY'S PURSUIT OF SLR FOR ITS EXISTING NUCLEAR FLEET?**

A. No, because the existing nuclear fleet can serve as a foundational component of complying with Section 110.9. In addition, the costs of the existing nuclear fleet are already reflected in customer rates.

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However, I am not advocating that SLR and continued operation of the existing plants be pursued blindly. The SLR process should identify the actions necessary to continue safe and reliable plant operations and carefully weigh the costs against the benefits and potential alternative solutions. In addition, Duke must demonstrate that the SLR costs incurred are reasonable and prudent before it can recover those costs from ratepayers. In future Carbon Plans, Duke should clearly lay out its schedule for pursuing SLR for each existing nuclear plant, along with a contingency plan should any nuclear plant not achieve its SLR in time to continue operations.

**Q. HAS DUKE COMPLETED NUCLEAR LICENSE RENEWAL BEFORE?**

A. Yes, Duke has successfully completed a license renewal for its entire nuclear fleet, allowing all generators to operate an additional 20 years beyond the original 40 years. If Duke successfully obtains a second SLR, the retirement dates for its nuclear generation will shift back another 20 years (which would move the first retirement to 2050 and the last to 2066).

**Q. BASED ON YOUR REVIEW AND INTERPRETATION OF OTHER INTERVENOR COMMENTS, DID ANY INTERVENOR DIRECTLY OPPOSE SLR?**

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A. The intervenors discussed nuclear generation in general. At least one focused on the lack of analysis of the economic risks and reliability considerations associated with SLR. While some intervenors were strongly in favor of, or opposed to, nuclear energy, no intervenor engaged in a substantive discussion of the specifics of Duke's SLR proposal and concluded (on the merits of SLR, itself) that it should not be pursued. No intervenor discussed the use of SLR on the merits in combination with the acquisition of a lower cost alternative to replace the magnitude of firm capacity and energy provided by the current nuclear fleet.

**Q. HAVE ANY NUCLEAR POWER PLANTS RECEIVED A SLR?**

A. To date only three nuclear power plants, none owned by Duke, have received an SLR. Earlier this year the Nuclear Regulatory Commission (NRC) reset the licenses of two of those three back to a 60-year life versus the 80-year life. Dominion's Surry nuclear station is the only nuclear station to have an approved application to extend its operation to 80 years.

**Q. DO YOU HAVE ANY CONCERNS ABOUT THE NRC'S SLR RESET AND THE IMPACT ON DUKE?**

A. No. Based on my review of the SLR process and the two licenses that the NRC reset, those owners will likely need to re-evaluate environmental issues specific to each request. At this time, the NRC

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has not rejected or denied any SLR but has recommended re-evaluation via a reset. Duke will likely incorporate any lessons learned in its SLR applications and NRC discovery.

Historically, SLR requests have taken approximately two years to complete and may take longer if the applicant triggers a re-evaluation. If an SLR is not granted or if the application process takes longer than two years, Duke has adequate time to adapt and re-address this topic in future carbon plan updates. Duke's earliest nuclear license is not scheduled to expire until 2030.

**Q. DO YOU AGREE WITH NC WARN'S RECOMMENDATION THAT THE EXISTING NUCLEAR FLEETS BE CONVERTED TO SYNCHRONOUS CONDENSERS POST-2035?**

A. No. A synchronous condenser provides spinning inertia that balances system stability and provides reactive power.[18] It absorbs disruptions on the grid and allows for high power quality.

NC WARN's idea is novel but is not likely the best utilization of Duke's nuclear fleet. Turning Duke's nuclear fleet into essentially a "shock absorber" to resolve minor system fluctuations and imbalances of intermittent generation would likely result in increased costs to customers. Nuclear generation in the Carolinas provides baseload

[18] https://www.ge.com/steam-power/products/synchronous-condenser

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generation. To the extent that NC WARN believes that its proposal is viable for the ratepayers of North Carolina as well as providing stability for the Bulk Electric System, it should provide timing, risk, and economic evaluations in future filings to support its recommendation, including input from the NRC to determine if the existing nuclear generation fleet could operate as synchronous condensers without the need to modify license requirements, technical specifications, and refueling intervals.[19]

NC WARN did not provide the details necessary to engage in a substantive discussion of its proposal. Nor did it identify the resources that would be required to replace the approximately 11 GW of nuclear baseload capacity operating in the DEC and DEP balancing areas while maintaining system reliability. In addition, NC Warn does not account for the fact that DEC is a minority owner of the Catawba nuclear station,[20] with the balance being owned by parties not subject to Section 110.9. Finally, NC Warn does not address existing contractual agreements for DEC to provide power

[19] NC WARN should also address other impacts, including but not limited to: additional operations and maintenance; premature equipment failure given the likely nature of cycling as the resources would be load following; potential impacts to reactor physics; fuel burn and fuel load; and impacts to spent fuel pool storage given the need for unused energy to decay.

[20] DEC owns approximately 19.4% of the approximately 2,400 MW Catawba nuclear station. The other owners are the North Carolina Municipal Power Agency 1, the North Carolina Electric Membership Corporation, and the Piedmont Municipal Power Agency (SC).

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to these other entities from other DEC nuclear facilities when the Catawba units are out of service.

**Q. DO YOU AGREE WITH CIGFUR'S CONTENTION THAT SLR COSTS ARE NOT INCLUDED IN DUKE'S PROPOSED CARBON PLAN?**

A. Yes, Duke failed to include expected SLR costs in its Proposed Carbon Plan. In review of Duke responses to CIGFUR discovery and PS DR 13-2, I confirmed that SLR costs were omitted from the present value of revenue requirement (PVRR) and bill impact calculations presented in the Proposed Carbon Plan.

**Q. DOES THE PUBLIC STAFF HAVE ANY CONCERNS WITH DUKE'S EXCLUSION OF THE EXPECTED SLR COSTS FROM THE BILL IMPACT ANALYSIS OR PVRR?**

A. Yes. From a modeling sense, I agree with Duke's inferred explanation that the PVRR impacts illustrated in the Carbon Plan are the incremental costs of compliance, exclusive of common costs that would be incurred across all portfolios. Duke has modeled SLR extensions in previous IRPs and would likely do so in the future with or without Section 110.9. I disagree with Duke's exclusion of SLR from bill impacts. As we have highlighted in our Initial Comments, the bill impacts shown in the Carbon Plan do not represent the entire cost impact to ratepayers.

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Duke should provide an additional analysis that shows the most likely bill impact on ratepayers for the utilities' total expected costs to allow stakeholders to determine total bill impacts and aggregated PVRR, as described in the testimony of Public Staff witness James McLawhorn. It is important for the Commission to consider the total rate and bill impact to North Carolina customers.

## VII. Transmission Planning, Proactive Transmission, and RZEP

**Q. PLEASE SUMMARIZE THE PUBLIC STAFF'S DISCUSSION OF TRANSMISSION PLANNING IN ITS INITIAL COMMENTS.**

A. As discussed extensively in comments and my testimony, the generation fleet is undergoing significant transition; however, this transition cannot be considered in isolation from the impact on the transmission system. When combined with increasing demand growth, the transmission planning processes must be evaluated and modified. The Public Staff stated in its comments that transparent, longer term transmission planning may be a valuable tool to help inform potential proactive upgrades, including their time requirements. The Public Staff explained the difference between reactive upgrades and proactive upgrades, and described the timing considerations that are part of prudent utility planning. The Public Staff further explained the increasing power flows from DEP to DEC, highlighting the fact that DEP generation and transmission will be

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utilized to meet the needs of DEC's customers without adequately compensating DEP's ratepayers. In its Initial Comments, the Public Staff supported the general concept of proactive transmission planning and upgrades, and acknowledged that it is warranted to meet the goals of the Carbon Plan but noted that appropriate cost allocation must be evaluated prior to implementation. The Public Staff also requested that any proactive transmission projects be excluded from the multiyear rate plan (MYRP) until the issues in its Initial Comments are resolved.

**Q. IN ITS ISSUES REPORT FILED ON JULY 22, 2022, DUKE AGREED TO PERFORM SUPPLEMENTAL PLANNING ANALYSIS FOR THE PUBLIC STAFF TO ADDRESS THE NEED FOR RED ZONE TRANSMISSION EXPANSION PLAN PROJECTS. PLEASE DISCUSS DUKE'S COMMITMENT AND THE IMPETUS FOR THIS ANALYSIS.**

A. The Red Zone is an area of transmission constraints located in two parts of Duke's service territory. For DEP, the Red Zone is generally in southeastern North Carolina, which is highly suitable for solar development due to its flat terrain, relatively low land costs, and relatively high solar insolation; however, the transmission in this area is also highly constrained due to historical load requirements and, more recently, increased solar development. These transmission constraints were major issues in the Commission's review of two

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solar CPCN applications – Friesian Holdings, LLC, in Docket No. EMP-105, Sub 0, and Juno Solar, LLC, in Docket No. EMP-116, Sub 0. For DEC, the Red Zone is generally in the northwest part of South Carolina, near the North Carolina border. Both DEC's and DEP'S Red Zones have relatively high solar insolation. The historic success of solar development interconnected to Duke's distribution and transmission systems in these areas has contributed to the transmission system reaching a saturation point, i.e., the system has too much generation and not enough load in discrete line segments of the distribution and transmission system. Each utility's unique electric circuit configuration, such as the use of lower voltage transmission, has also created challenges for further large-scale adoption in specific areas of the system.

The supplemental planning process listed in Duke's July Issues Report is a valid effort to refine the study process to determine potential proactive upgrades. This proactive study approach identifies areas of transmission lines that have been targeted by previous interconnection requests,[21] highlighting that the study results could be (and likely would be) an identification of common upgrades. The study centered on historic interconnection requests

[21] The study included analysis of transmission projects located outside the Red Zone that are not currently under consideration but may be candidates for future proactive transmission plans.

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and was not a least-cost analysis.[22] As the Public Staff stated in its Initial Comments, proactive transmission upgrades require a balance of least-cost and least-regrets planning, coupled with a robust, forward looking planning process. Undoubtedly, Section 110.9 compliance will require more solar generation, and all portfolios filed in this docket require interconnection of at least 5 GW of solar (including solar plus storage) over the next decade. Some intervenors have stated this amount should be much higher over the next several years based on alternative modeling results. Therefore, a least-regrets approach for proactive transmission is reasonable because Duke will add solar and other low or no carbon resources in later years, likely exceeding the 5 GW amount by the late 2030s.

This modified transmission study addressed some of the concerns the Public Staff has raised in the NCTPC process. Duke used realistic assumptions regarding circuits of certain voltages (e.g., limited amounts of generation can interconnect onto 44 kV lines) to minimize the likelihood that a large number of projects could interconnect on a part of the system where such growth would not be reasonable. The study assumptions also addressed concerns

[22] For clarification, I am not aware of the existence of any other alternate analysis that was completed to compare or contrast the line upgrades Duke selected. This does not imply that Duke's solution is not least cost; it is not clear whether there were other alternatives that could have achieved the same mitigation, such as alternate line analysis, non-wires alternatives, etc. I acknowledge the timing constraints of this study and need of timely completion for Duke's testimony.

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around speculative generation of solar facilities and changing land availability. The study went further to isolate solar facilities that were extraneous and required substantial line upgrades that mostly benefited one interconnection request. The amount of solar MWs studied was the same amount identified in Duke's proposed Carbon Plan, and the study attempted to maintain the solar allocations used in Duke's proposed Carbon Plan. For modeling purposes, no more than 60% of new solar generation for DEP and DEC combined may be located in the current DEP balancing area.

**Q. DID DUKE COMPLETE THE REVISED TRANSMISSION STUDY?**

A. Yes. A summary of the revised transmission study and the results can be found in the joint testimony of the Transmission Panel.

**Q. HAS THE PUBLIC STAFF REVIEWED THE NEW STUDY?**

A. The Public Staff was able to review the new study at a very high level but did not have sufficient time for follow-up discovery or further discussion with the Company. I have no reason to doubt the integrity of the study.

**Q. DO YOU BELIEVE THE SUPPLEMENTAL TRANSMISSION STUDIES SUPPORT THE NEED FOR THE REQUESTED RED ZONE TRANSMISSION PROJECTS AT THIS TIME?**

A. Generally, yes, with certain exceptions and caveats that I will expand upon below.

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**Q. PLEASE PROVIDE ANY INFORMATION IN THIS NEW STUDY THAT YOU BELIEVE IS RELEVANT AND ANY FURTHER RECOMMENDATIONS YOU MAY HAVE.**

A. Overall, Duke's study methodology addressed the Public Staff's concerns regarding the reasonableness of the projects sampled to evaluate the transmission impacts. While the study included approximately the same capacity of solar resources as identified in the Proposed Carbon Plan, it was based on historic queue information, while future generation may have different technical characteristics or points of interconnection. In addition, the study did not include significant levels of storage or solar plus storage, despite the large quantity of these resources that are also likely to be procured over the next several years to meet the carbon reduction targets of Section 110.9. The results of this evaluation in combination with the current Definitive Interconnection System Impact Study (DISIS) project locations[23] continue to support constructing upgrades that are likely or common to multiple solar projects. While the results were similar to those in previous studies, the new study had a few discrete changes and supported a delay of some upgrades. Below, I discuss the upgrades and recommendations for each of the respective service territories.

[23] As shown in Figure 2: 2022 DISIS Red-Zone Map, Transmission Panel's Testimony at 35.

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**DEC Transmission Study**

The study results can be found in Transmission Panel Exhibits 1 and 3. The study was comprised of 37 individual solar facilities and the Transition Cluster Study aggregated results totaling 1,900 MW. For DEC, three out of the four proposed transmission projects would facilitate the interconnection of over 80% of all generation facilities seeking to interconnect, providing a positive correlation of potential upgrades in DEC to likely areas of interconnection. However, Project #4, the Clinton 100kV (Bush River-Laurens) line, had many fewer generator facilities necessary to support the upgrade. Transmission Panel Exhibit 3, Table B, also listed other potential upgrades in addition to the four proposed projects.

Based on the information known to date, I would not recommend DEC build Project #4 at this time, based on the relatively few generator facilities impacting that line and the unclear causal relationship between future solar generation and this upgrade. Based on my review of a transmission map, I understand that this potential line upgrade will likely be needed in the near future if solar generation continues to attempt to interconnect in this area given its proximity to the other transmission projects in question. The additional upgrades listed in Table B appear likely to be needed in the near term, depending on where future generation seeks

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interconnection. Currently, the precise capacity of solar or solar plus storage that Duke will need in future procurements, and the proportion between the two, is uncertain. Further, the incremental solar capacity that is dependent on Projects #1 thru #3 or Project #4 is unclear. The Public Staff requests that Duke address in rebuttal whether exclusion of Project #4 would challenge the reliability of the existing transmission system or if it is more cost effective to perform the upgrades at the same time as Projects #1 thru #3. Duke should also explain why Project #4 is needed based on more than just historic interconnection requests, such as the 2022 DISIS results and if there is any potential if further development of solar plus storage would mitigate the need for Project #4.

**DEP Transmission Study**

The DEP study results can be found in Transmission Panel Exhibits 2 and 4. The study was comprised of 44 solar facilities and the Transition Cluster Study aggregated results, totaling 3,500 MW. For DEP, four out of the 14 proposed transmission projects would facilitate the interconnection of over 50% of the studied solar facilities and nine out of the 14 proposed transmission projects would facilitate the interconnection of solar facilities. This finding suggests a stronger relationship between common upgrades than just the TCS results indicated, highlighting the continued interest of developers to locate

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in these areas of DEP's system. Duke recommended delaying three of DEP's 14 transmission projects (Projects #9, #11, and #12) because they did not show a strong dependance in the transmission study.[24] I agree that these projects should be delayed based on the study. Further, I recommend that Projects #7 and #14 be removed from the RZTEP at this time. Projects #7 and #14 have approximately 25% of all common upgrades affecting the proposed transmission projects in the study (24% and 26%, respectively). Project #14 appears relatively small in scope compared to the other transmission upgrades. Removal of Projects #7 and #14 is separate from the results of a power-flow analysis (or equivalent) or project estimated completion timeline. The Public Staff requests that Duke address in rebuttal whether exclusion of Projects #7 and #14 would challenge the reliability of the existing transmission system or if it is more cost effective to perform the work at the same time as the other red zone Projects in the general vicinity and explain how Project #7 is needed based on more than just historic interconnection requests.

**Q. DOES THE PUBLIC STAFF HAVE ANY CONCERNS REGARDING THIS NEW TRANSMISSION STUDY?**

[24] Transmission Panel, Exhibit 2 at 1 and Exhibit 4, at 3.

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A. Yes. The accuracy of Duke's cost assumptions and the effect of current inflationary pressures are unknown.[25] The costs listed in the study may change given their preliminary nature and the scope of work, which will take years to complete. Cost over-runs are not necessarily the result of imprudence, but I am raising this concern given the potential uncertainty and cost exposure of ratepayers.[26]

Again, the Public Staff supports the concept of proactive upgrades and least-regrets planning to ensure timely compliance with Section 110.9. The Public Staff's support of proactive upgrades in this instance, however, should not be construed as precedent or indicative of future Public Staff recommendations. Proactive upgrade planning is a tool that can be used for efficient planning of the electrical system while ensuring system reliability and achieving policy goals, and the Commission should direct Duke to adopt the transmission planning-related recommendations in the Public Staff's Initial Comments.[27] The Public Staff is also not making recommendations at this time on whether the costs are reasonable and prudent; the Public Staff will make those recommendations when Duke seeks cost recovery.

[25] Almost all cost estimates are Class 5 estimates, which have an expected accuracy range of between -50% to -20% on the low side and +30% to +100% on the high side.

[26] This issue was also raised in the Public Staff's Initial Comments, at 80.

[27] Public Staff initial comments, at 24-27.

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I agree with Duke's Transmission Plan Exhibit 4 language:

> Note that while the fewer number of Red Zone requests in recent years may be due to the well-known congestion and upgrade costs in the Red Zones, elimination of Red Zone congestion with pro-active upgrades may incentivize a higher concentration of Red Zone requests than seen in recent years.

Interconnection requests are likely to increase in the Red Zone after Duke completes proactive upgrades of the transmission system. This increase could create congestion again; to the extent possible, Duke should evaluate future proactive upgrades to reflect anticipated interconnections over at least a ten-year horizon and potentially a twenty-year horizon, as recommended by the Public Staff in its Initial Comments, while creating milestone provisions to measure the need to move forward to the design and, if justified, construction of the projects.[28]

**Q. WHAT SHOULD THE NEXT STEPS BE AFTER THE REVIEW OF THIS REVISED TRANSMISSION STUDY?**

A. Mitigating execution risk to achieve Section 110.9 compliance requires proactive transmission planning and proactive upgrades. The Commission should acknowledge the public policy goals for

[28] "Direct Duke to expand its internal transmission planning horizon to 20 years." Public Staff Initial Comments, at 25.

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North Carolina as part of its 2022 Carbon Plan, as requested by Duke.[29]

Following the issuance of the Commission's 2022 Carbon Plan, proactive upgrades will be presented in the 2023 NCTPC planning process. If approved by the NCTPC, the planned proactive upgrades will be included in the baseline for future DISIS cluster studies. I request that Duke confirm my understanding of the NCTPC process for determining proactive upgrades in rebuttal.

If the Commission acknowledges the need for proactive transmission upgrades in its Carbon Plan, the Commission should require Duke to file a report on the status of the upgrades in a dedicated docket or sub-docket to include current project timing milestone completion and cost estimates on a semi-annual basis.

In addition, the Commission should require and approve a cost allocation or cost sharing mechanism for DEC and DEP to share the cost of the proactive upgrades. The flow of power from DEP-located generation to serve DEC load is a concern of the Public Staff.[30] DEC's customers should pay their fair share of the DEP transmission and plant investments that serve DEC's load so that DEP customers

[29] This was addressed in the Public Staff's initial comments, at 161.

[30] Initial Comments of the Public Staff, at 110.

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do not disproportionately bear the burden of statewide carbon reduction.

**Q. COULD YOU PLEASE DESCRIBE THE TRANSMISSION RECOMMENDATIONS IN THE TECH CUSTOMERS REPORT?**

A. I will discuss two primary topics listed in the Tech Customers Report: (1) excess transmission availability at retiring generation stations; and (2) and surplus interconnection availability. The first topic relates to the retirement of older generation and installation of new generation at the same location. Locating replacement generation at the site of retiring generation capacity could utilize the existing transmission system and mitigate adverse power flows. However, all new generation might not be able to easily interconnect at the existing generation sites due to differing technologies that require upgrades that are not least cost.[31] The Commission should not consider retirement of existing generation resources solely to enable less carbon-intensive generation interconnection at the same site when there has been no evaluation of system impacts. While this

[31] Multiple factors will need to be assessed when considering generation. For thermal generation, one would need to consider fuel supply and cooling (access to water). One would also consider proximity to areas not susceptible to large solar arrays build out and economies of scale; either urban or highly dense residential areas or limited concurrent parcel access given proximity to lakes and limited land availability that is for or lease. Solar insolation levels may not be ideal for certain locations compared to others. One would also need to consider transmission or point of interconnection routing availability to the existing substation; longer distances away from the substation and generation that has low energy output per acre will likely trigger more overhead or underground wire management.

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solution may appear tempting from a capacity expansion modeling perspective, it does not account for the complexities of system power flows on the transmission system, which require additional detailed evaluation. However, it is clear through Duke's pursuit of a generator replacement process at FERC[32] that Duke believes this concept, at least in part, has merit, and the Public Staff encourages Duke to carefully evaluate generator replacements in order to provide ratepayers with the most cost-effective solution.

The second topic centers on the Surplus Interconnection Service which allows a new resource to co-locate at an existing facility's point of interconnection, with energy injection split between the resources up to the maximum output level for the existing facility. I believe this approach does not properly consider capacity resources or firm commitment of the resource for planning and system operations. This approach requires that an existing generation resource be studied under a firm commitment, or 100% of its nameplate capacity being available, but a new resource would be studied on an energy-only basis. While there may be some limited use for Surplus Interconnection Service, this needs to be evaluated on a case-by-case basis to ensure that the lack of firm capacity associated with the surplus resource is not detrimental to system planning or

[32] Transmission Testimony, at 51.

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operations. For example, if a solar plus storage facility is co-located with an existing CT, the CT could operate when needed in the winter morning when the solar facility output is near zero. In times when the CT is not operating, the solar plus storage resource could utilize that transmission head room. Thus, this process provides no incremental firm capacity, but could provide additional lower carbon intensive generation.

Both topics are appropriate for review during a CPCN or CECPCN proceeding and evaluation of alternative scenarios, as both proposals require site-specific reviews that cannot easily be incorporated into high level capacity expansion planning. The Public Staff recommends that in future CPCN or CECPCN filings, Duke should address whether there are cost savings that could be achieved via the Surplus Interconnection process.

## VIII. <u>Reliability</u>

**Q. DOES THE PUBLIC STAFF HAVE CONCERNS WITH DUKE ENERGY'S USE OF A RESERVE MARGIN IN THE CARBON PLAN?**

A. No. The Resource Adequacy Study Duke filed in Docket No. E-100, Sub 165, explains the reserve margin, the need for a reserve margin, and how the reserve margin can potentially change over time or be influenced by external factors.

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**Q. WOULD MERGING DEC AND DEP HELP LOWER THE COMBINED SYSTEM RESERVE MARGIN COMPARED TO THE INDIVIDUAL UTILITIES?**

A. Most likely. The Resource Adequacy Study confirms that merging the utilities would provide more load and generation diversity and would lower the required reserve margins.[33] In addition, and more importantly, merging the utilities would allow DEC and DEP to share capacity resources within the capacity expansion models. As Duke currently models its combined system, both DEC and DEP must maintain individual reserve margins; allowing them to share firm capacity within the model by merging utilities would potentially reduce the total new capacity that must be built (assuming that intertie transfer capability is sufficient). This could result in significant cost savings to ratepayers, and this sharing of firm capacity would not be enabled through combining balancing authorities. Increasing intermittent generation may require future increases in the reserve margin; however, merging DEC and DEP could mitigate this need by permitting firm capacity to be shared.

**Q. DO YOU AGREE WITH NC WARN'S REQUEST THAT THE COMPANIES SHOULD BE ORDERED TO ASSUME THAT THEY**

[33] The Combined Case Sensitivity found in the Proposed Carbon Plan, Attachment II, at 62.

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**WILL MEET WINTER PEAK DEMAND WITH AVAILABLE NON-FIRM IMPORTS"?**[34]

A. No. Solely relying on non-firm energy during the winter peaks would be imprudent and potentially dangerous. Nor do I believe it would be prudent to assume that a loss of generation during a contingency event could be fully mitigated in every occurrence with non-firm resources. A function of the reserve margin is to maintain a reasonable level of system reliability. Non-firm power is just what the name implies; it is not firm, and it may or may not be available when it is needed. Even if it is available, it is subject to being curtailed at any time.

**Q. WOULD YOU AGREE THAT BASED ON THE REPORT BY NC WARN'S CONSULTANT, MR. POWERS, DUKE ENERGY HAS UTILIZED NON-FIRM POWER DURING PEAK PERIODS?**

A. While I have not confirmed every specific date listed in Mr. Powers' report, I have no reason to doubt Mr. Powers' observation that non-firm energy has been used by Duke to maintain reserves.

For example, Table 11 of Mr. Powers' report shows that DEC purchased 1,412 MW from Santee Cooper during a polar vortex event on February 20, 2015. DEC's February 2015 Fuel Report in Docket No. E-7, Sub 1075 shows that in that month DEC bought

[34] Comments filed on July 15, 2022, page 6.

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5,199 MWh from Santee Cooper (labeled as SC Public Service Authority-Emergency). The Public Staff reviewed this purchase in DEC's annual fuel rider in Docket No. E-7, Sub 1104 and did not find imprudence. The affidavit of Public Staff witness Jay Lucas stated that Marshall Steam Station Unit 4 was out of service from April 2014 through March 2015. Marshall Unit 4 has a 660 MW nameplate capacity, roughly half of the 1,412 MW import from Santee Cooper. The Monthly Baseload Power Plant Performance Report for the same period (February 15, 2015) shows that DEC also had an outage at Marshall Steam Station Unit 3, which has approximately the same nameplate rating as Marshall Unit 4. These events show the difference between the system capacity planning performed in IRP proceedings and the operational flexibility that is needed for emergency events, such as multiple generator outages. During emergency events, Duke should pursue and has pursued all available options to cost-effectively serve its customers, which may include firm and non-firm purchases, activating DSM reserves, interruptible customers, and load shedding. However, it is imprudent to plan a system that must continually rely upon non-firm resources.

**Q. DO YOU AGREE WITH MR. POWERS' RECOMMENDATION TO RETIRE MAYO AND ROXBORO?**

A. No, I do not. Mr. Powers states:

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> The Companies are maintaining excessive reserve margins. Adjusting the current supply portfolio to meet the PRM [planning reserve margin] target of 17 percent would enable the immediate retirement of at least 3,000 MW of capacity while meeting the target PRM of 17 percent. This would enable retirement of the Mayo and Roxboro coal plants, with a combined capacity of about 3,200 MW, in 2024 while meeting a 17 percent PRM.[35]

I disagree with this recommendation for multiple reasons. First, his assumption that <u>all reserves</u> can be served solely from non-firm supplies is incorrect as I stated above and would likely lead to the Public Staff recommending that the Commission find the Company to be acting imprudently. Second, Mr. Powers did not provide any type of transmission evaluation and impact analysis on such a large-scale retirement, including whether DEP could adjust in a timely manner to ensure the safe and reliable operation of its electrical grid. The evaluation of transmission impacts for these two power stations

[35] Joint Comments of NC WARN and Charlotte Mecklenburg NAACP, Docket No. E-100, Sub 179, Attachment 1, at 34 (July 15, 2022).

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1 has been discussed in previous dockets by the Public Staff [36] in great
2 detail. Third, his recommendation singles out DEP coal generation
3 plants and does not include the same recommendation for the DEC
4 coal generation fleet.

5 In Mr. Powers' report, the DEC coal generation fleet, which has been
6 converted to dual fuel operation, must run from natural gas only.
7 However, most of the DEC plants that have been converted to dual
8 fuel must operate at less than the nameplate rating if relying only on
9 natural gas. This concern is further compounded by the possibility of
10 having to rely on non-firm natural gas delivery. Further, Mr. Powers
11 does not discuss the ratemaking aspects or cost recovery associated
12 with the accelerated retirement of the generating plants.

[36] "In addition, Duke's coal unit retirement analysis in the IRP took into account aspects of potential transmission upgrades. It is the Public Staff's understanding that retirement of the Roxboro and Mayo units will cause the greatest stress on the transmission system, because of the significant amount of capacity in this geographic area, the overall demand, and system interties with other utilities. The Public Staff believes the model inputs relied upon by Duke are reasonable for planning purposes, but notes that cost savings from the replacement generation may not materialize for numerous reasons including failure of critical equipment, higher than estimated fuel costs, higher than estimated construction costs, and the ultimate selection of replacement resources other than what is modeled. As discussed extensively in the 2019 rate cases and in the current IRPs, the Companies' transmission requirements are dynamic as related to the retirement of coal units. Should the Commission approve accelerated coal unit retirements for economic, earliest practicable date, or other reasons, the Public Staff recommends that Duke analyze the transmission impacts and file a more detailed plan with refined cost estimates, including timelines of required activities and potential synergies with future grid improvement plans, to aid in the transition and system production cost estimates with the proposed replacement generation source." Comments of the Public Staff, E-100, Sub 165, at 106-107.

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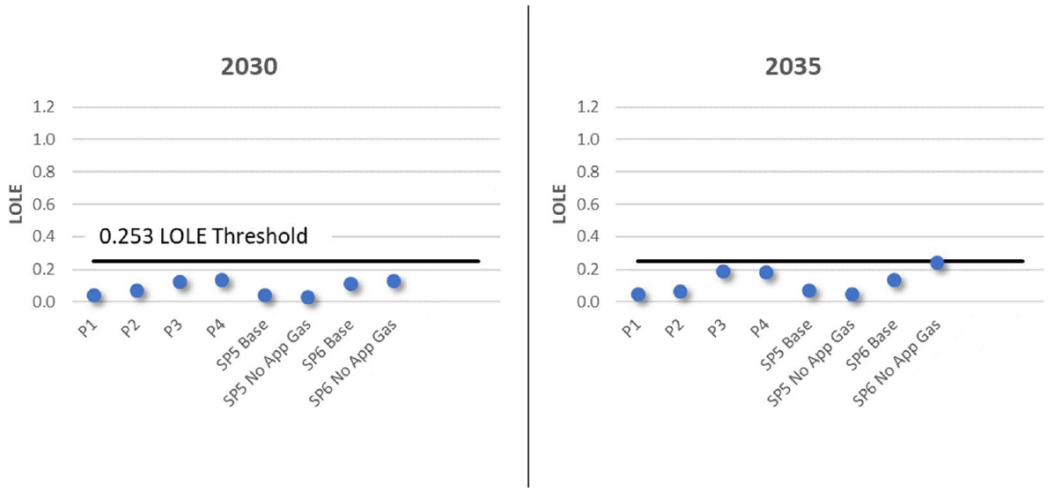
**Q. DID THE PUBLIC STAFF'S SUPPLEMENTAL PORTFOLIO SP5 WITH NO APPALACHIAN GAS STAY BELOW DUKE'S THRESHOLD FOR LOSS OF LOAD EXPECTATION (LOLE)?**

A. Yes. The testimony of Duke's Modeling Panel, Figure 18,[37] shows that the SP5 No App Gas supplemental portfolio run resulted in portfolios with a very low LOLE in the 2030 and 2035 model years. Shown below is a summary of LOLE results in 2030 and 2035 for the supplemental portfolios compared to the originally filed Duke portfolios:




Utilization of Duke's own LOLE threshold highlights that the SP5 No App Gas portfolio's LOLE adequately addressed system reliability concerns at the generation level while mitigating concerns about execution risk and compliance with Section 110.9 requirements.

[37] *See* Direct Testimony of Snider, McMurry, Quinto, p. 202.

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

2 A. Yes, it does.

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## APPENDIX A

## QUALIFICATIONS AND EXPERIENCE

DUSTIN R. METZ

Through the Commonwealth of Virginia Board of Contractors, I hold a current Tradesman License certification of Journeyman and Master within the electrical trade, awarded in 2008 and 2009 respectively. I graduated from Central Virginia Community College, receiving Associate of Applied Science degrees in Electronics and Electrical Technology (*Magna Cum Laude*) in 2011 and 2012 respectively, and an Associate of Arts in Science in General Studies (*Cum Laude*) in 2013. I graduated from Old Dominion University in 2014, earning a Bachelor of Science degree in Engineering Technology with a major in Electrical Engineering and a minor in Engineering Management. I completed engineering graduate course work in 2019 and 2020 at North Carolina State University.

I have over twelve years of combined experience in engineering, electromechanical system design, troubleshooting, repair, installation, commissioning of electrical and electronic control systems in industrial and commercial nuclear facilities, project planning and management, and general construction experience. My general construction experience includes six years of employment with Framatome, where I provided onsite technical support, craft oversight, and engineer design change packages, as well as participated in root cause analysis teams at commercial nuclear power plants, including plants owned by both Duke and Dominion. I also

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worked for six years for an industrial and commercial construction company, where I provided field fabrication and installation of electrical components that ranged from low voltage controls to medium voltage equipment, project planning and coordination with multiple work groups, craft oversight, and safety inspections.

I joined the Public Staff in the fall of 2015. Since that time, I have worked on both electric and natural gas matters including general rate cases, fuel cases, annual gas cost reviews, applications for certificates of public convenience and necessity, service and power quality, customer complaints, North American Electric Reliability Corporation (NERC) Reliability Standards, nuclear decommissioning, National Electric Safety Code (NESC) Subcommittee 3 (Electric Supply Stations), avoided costs and PURPA, interconnection procedures, integrated resource planning, and power plant performance evaluations. I have also participated in multiple technical working groups and been involved in other aspects of utility regulation.

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**The Public Staff – North Carolina Utilities Commission**
**Summary of the Testimony of Dustin R. Metz**
**Docket No. E-100, Sub 179**

The purpose of my testimony is to present the results of my investigation into Duke Energy Carolinas, LLC's (DEC) and Duke Energy Progress, LLC's (DEP) (collectively, Duke) Proposed Carbon Plan. My testimony supports the Public Staff's investigation into, and its Initial Comments on, Duke's Proposed Carbon Plan. My testimony highlights the Public Staff's recommendations that the Commission should consider not only the modeling results in Duke's Proposed Carbon Plan, but also less quantifiable factors, including the Proposed Carbon Plan's impact on system operations, as well as transmission planning, timing, and implementation.

My testimony explains that the Public Staff agrees with Duke's modeling approach that emissions from any new carbon-emitting resource will count against the interim and 2050 carbon emission reduction targets. I also state that retirement dates for each coal plant may require a degree of flexibility as the electrical system transitions to new technologies in order to meet the carbon reduction targets of S.L. 2021-165 (HB 951) while also maintaining system reliability. In addition, I testify that Long Lead-Time resources, as identified by Duke, can take up to and beyond a decade to plan, construct, and commission. While the Public Staff is technology agnostic, the modeling results suggest that small modular reactors and the Bad Creek II expansion project are reasonable for further evaluation to refine cost estimates and identify risk factors. At this time, based on continued modeling results, Duke should not pursue ownership of offshore wind. Duke has proposed

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$311M in wind lease area transfer and work-related costs over the next three years. The results of additional modeling have shown that offshore wind is not economically selected until after 2040, and therefore other work activities should be given prioritization at this time; however, offshore wind should be re-evaluated in the 2024 Carbon Plan update.

I also update the Commission on the subsequent license renewal (SLR) process for Duke's nuclear fleet. Duke's existing nuclear fleet is a foundational component of system reliability and carbon reduction for the Carolinas. However, SLR and respective costs to achieve SLR should not be pursued blindly and without evaluation of the risk and costs to implement and maintain these resources for an 80-year life.

Next, I provide the Commission with a summary of a revised transmission study completed by Duke. The revised transmission study resolved most of the Public Staff's concerns: reasonable thresholds of interconnection at specific voltage levels, mitigation of changes in land availability, removal of extraneous projects, and consistency with the solar allocation per Carbon Plan modeling. The results of this study further highlight common system upgrades needed for HB 951 compliance that would result in a "least regrets" outcome. I agree with most of Duke's proposed upgrades; however, I highlight certain requested/identified upgrades that should not be pursued proactively at this time. While I recommend that the Commission acknowledge the need for proactive transmission upgrades in its Carbon Plan, cost allocation/cost sharing of DEP transmission upgrades

needs to be addressed so that DEP customers do not disproportionately bear the burden of these costs to achieve statewide carbon reductions.

I conclude my testimony with the topic of reliability. It would be imprudent and dangerous for the electrical system to be served solely by non-firm resources. I also share the loss of load expectation (LOLE) results of P1 through P4 as well as SP5 and SP6. While the results vary by portfolio, the LOLE of all the portfolios remained below Duke's planning threshold.

This concludes my summary.

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**BEFORE THE NORTH CAROLINA UTILITIES COMMISSION**

DOCKET NO. E-100, SUB 179

| | | |
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| In the Matter of | ) | **TESTIMONY OF** |
| Duke Energy Progress, LLC, and | ) | **DAVID M. WILLIAMSON** |
| Duke Energy Carolinas, LLC, | ) | **PUBLIC STAFF –** |
| 2022 Biennial Integrated Resource | ) | **NORTH CAROLINA** |
| Plans and Carbon Plan | ) | **UTILITIES COMMISSION** |

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**Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.**

A. My name is David M. Williamson. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an engineer with the Energy Division of the Public Staff – North Carolina Utilities Commission.

**Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.**

A. My qualifications and duties are included in Appendix A.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. The purpose of my testimony is to provide the Commission with a summary of my review and investigation of the Proposed Carbon Plan of Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP) (collectively, Duke or the Companies), filed in this docket on May 16, 2022, as well as the initial comments filed by intervenors in this docket, and the direct testimony filed by the Companies on August 19, 2022. My testimony is organized based upon the July 22, 2022 Issues Report Submitted on Behalf of DEC and DEP (Issues Report), and in accordance with the Commission's

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July 29, 2022 Order Scheduling Expert Witness Hearing, Requiring Filing of Testimony, and Establishing Discovery Guidelines (Evidentiary Hearing Order).

**Q. HOW IS YOUR TESTIMONY ORGANIZED?**

A. Consistent with the Issues Report and the Evidentiary Hearing Order, my testimony addresses all sub-issues designated under the topic identified as "EE/DSM Issues/Grid Edge," and is divided into the following sections:

I. The Companies' Grid Edge initiatives and their influence on the net load forecast;

II. The Companies' proposal to use one percent of prior-year-available retail sales as the Utility Energy Efficiency forecast assumption;

III. The Companies' proposed regulatory changes; and

IV. The Companies' proposed Flexibility and Rapid Prototyping Guidelines.

**Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.**

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A. My testimony supports the Public Staff's Initial Comments filed in this docket on July 15, 2022, and its investigation into Duke's Proposed Carbon Plan. I also address intervenor comments on a wide range of issues within the Demand-Side Management (DSM)/Energy Efficiency (EE) and Grid Edge topics identified for the evidentiary hearing track. I provide several recommendations to the Commission regarding issues within the DSM/EE and Grid Edge topics.

First, I discuss the components of the Companies' Grid Edge initiatives and the individual forecasts that were used to create the net load forecast for the Proposed Carbon Plan. I also discuss various intervenor concerns that were brought up in the Issues Report involving these forecasts.

Second, I discuss the Companies' incorporation of a one percent of prior-year-available retail sales as the modeling assumption for its Utility Energy Efficiency (UEE) forecast. I recommend that the Commission find that this assumption is not reasonable and prudent for planning purposes. Instead, I recommend the use of the Companies' most recent Market Potential Study (MPS) as the

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modeling assumption to be incorporated into the Commission's Carbon Plan in future Carbon Plan proceedings.

Third, I discuss Duke's request for acknowledgement of several regulatory changes that the Companies have identified as "enablers" to achieve their targeted one percent of prior-year-available retail sales. I do not recommend that the Commission approve the regulatory changes sought by the Companies at this time.

Finally, I discuss Duke's request for the Commission to acknowledge that a proposal for additional flexibility and rapid prototyping guidelines for DSM/EE pilots and rate designs is reasonable for future proceedings. I recommend that the Commission deny the Companies' request in this Carbon Plan proceeding.

## I. <u>The Companies' Grid Edge Initiatives and their Influence on the Net Load Forecast</u>

**Q. WHAT IS THE PUBLIC STAFF'S UNDERSTANDING OF THE TERM "GRID EDGE"?**

A. "Grid Edge," as described in the Proposed Carbon Plan, is a collection of tools and technologies that customers can utilize to control their energy experience. It involves typical EE and DSM

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1 programs or measures, electric vehicles (EVs), and renewable
2 energy generation technologies, all of which are encapsulated within
3 the term "Distributed Energy Resources" (DERs). Additionally, Grid
4 Edge includes dynamic rate tariffs that use a variety of pricing
5 strategies to motivate customers to shift usage from higher-cost, on-
6 peak hours, to lower-cost, off-peak hours.

7 In order to forecast customer energy and capacity requirements
8 across the 15-year planning horizon set forth in the Proposed Carbon
9 Plan, the Companies have expanded the net load forecast modeling
10 to include these Grid Edge activities to provide a more accurate
11 picture of DEC's and DEP's supply-side resource needs. While load
12 forecasting has always incorporated the manner in which customers
13 use energy, the requirements set forth in N.C. Gen. Stat. § 62-110.9
14 (Section 110.9) requires a more sophisticated review and
15 consideration of DERs and how DERs impact the peak demands and
16 energy sales that underly the law. Pursuant to Commission Rule R8-
17 60, the Companies update their base load forecasts every two years,
18 and this biennial exercise will allow the Companies to update the
19 individual forecasts of the components, reflective of Grid Edge

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activities, to incorporate current regulatory conditions and customer adoption trends.

**Q. DOES THE PUBLIC STAFF HAVE CONCERNS REGARDING THE FORECASTS OF THE INDIVIDUAL COMPONENTS OF THE COMPANIES' GRID EDGE INITIATIVE?**

A. Yes. In its Initial Comments, the Public Staff discussed concerns about Duke's UEE forecasting. Specifically, the Public Staff takes issue with: (1) the Companies' hard-coding of one percent of prior-year-available retail sales, bypassing DEC's and DEP's MPS;[1] and (2) regulatory changes proposed by the Companies to maximize the savings Duke can "claim" as UEE for purposes of Carbon Plan compliance, and the resulting unintended impacts in DSM/EE Rider proceedings. For the individual forecasts associated with demand response, net energy metering (NEM), EVs, and dynamic rate designs, the Public Staff did not take issue in its Initial Comments with the underlying forecasts that fed into the net load forecast. The Public Staff will continue to monitor changes to the load forecasts

[1] In response to a Public Staff data request, Duke indicated that its calculation of "available retail sales" represents the total sales minus the opted-out customer sales.

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and associated inputs in future Carbon Plan updates, Integrated Resource Plans (IRPs), and other proceedings. However, for purposes of this initial proceeding, the Public Staff does not take issue with these inputs with the exception of the savings associated with the Companies' UEE forecast.

**Q. DID OTHER INTERVENORS HAVE CONCERNS WITH THE FORECASTS OF THE INDIVIDUAL COMPONENTS OF THE COMPANIES' GRID EDGE INITIATIVE?**

A. Yes, NC WARN and NAACP Charlotte-Mecklenburg County Branch #5376-B (together, NC WARN, *et al.*), as well as Carolina Industrial Group for Fair Utility Rates II and Carolina Industrial Group for Fair Utility Rates III (together, CIGFUR) raised concerns in their issues list, which I discuss below.

*NC WARN, et al.*

NC WARN, *et al.* asks the Commission to require that Duke's Grid Edge programs be prioritized above other programs to achieve compliance with Section 110.9.[2] The Public Staff agrees in principle that it is preferable to reduce the need to build capital-intensive

[2] NC WARN, *et al.*'s Initial Comments, pp. 32-34.

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1 resources through the use of cost-effective alternatives so long as
2 system reliability is not compromised and those alternatives are
3 least-cost. In their Joint Testimony filed in this docket on August 19,
4 2022, Duke witnesses Tim Duff and Lon Huber state that the
5 Companies have placed an emphasis on "shrinking the challenge" of
6 complying with Section 110.9 by lowering the load forecast and
7 incorporating more DSM/EE and renewable resources through a
8 variety of programs.[3]

9 NC WARN, *et al.*'s primary concern seems to be related to the
10 forecast of the Companies' NEM programs.[4] NC WARN, *et al.* takes
11 issue with the fact that the NEM load forecast included in the
12 Proposed Carbon Plan is lower than the forecast that was provided
13 in the Companies' 2020 IRP.[5] Forecasts, which are used to illustrate
14 the effect of anticipated changes in load on resource availability and
15 need, are updated periodically with new data and incorporated into
16 subsequent modeling efforts. The Companies and intervenors are
17 currently addressing Grid Edge uncertainties impacting load

[3] Duke witnesses Duff and Huber's Joint Testimony, p. 5.
[4] NC WARN, *et al.*'s Initial Comments, p. 33.
[5] *Id*. at 34 (referencing the Companies' 2020 IRPs in Docket No. E-100, Sub 157).

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1 forecasts in pending dockets regarding Duke's NEM policy changes[6]
2 and the Smart $aver Solar EE program.[7] Once these dockets have
3 been resolved, the NEM forecast will be updated in future Carbon
4 Plan proceedings to reflect any new modeling assumptions.

5 *CIGFUR*

6 CIGFUR's concerns with regard to the Companies' forecasts of the
7 individual components of the Grid Edge initiative center around two
8 issues: (1) the Companies' efforts to increase flexible load of certain
9 commercial and industrial customers as a demand response
10 resource; and (2) expanding existing and implementing new
11 customer renewable energy programs.[8] Much of the debate
12 surrounding the use of flexible loads and dynamic pricing strategies
13 has occurred, to date, within the Companies' Comprehensive Rate
14 Design Study resulting from the 2019 rate cases.[9] In their Joint
15 Testimony, Duke witnesses Duff and Huber mention current
16 discussions regarding new flexible load and dynamic pricing

[6] Docket No. E-100, Sub 180.
[7] Docket Nos. E-2, Sub 1287 and E-7, Sub 1261.
[8] CIGFUR's Initial Comments, p. 41.
[9] Docket Nos. E-2, Subs 1219 and 1193 and E-7, Subs 1213, 1214, and 1187.

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1 programs.[10] The Public Staff believes that many customers are
2 interested in implementing cost-effective programs that would be
3 responsive to the issues CIGFUR has raised in this proceeding. The
4 Public Staff generally supports investigating flexible load and
5 dynamic pricing programs in the upcoming DEC and DEP rate cases,
6 in tandem with other issues involving cost of service and rate design.

7 Flexible load programs that allow existing loads to transition toward
8 dynamic pricing strategies and to receive service on a marginal cost
9 basis create the potential that the utilities may not sufficiently recover
10 fixed costs to serve customers' load. It is important to remember that
11 this existing load is included in Duke's load forecasting, and capacity
12 has been set aside to serve that load. Shifts in cost recovery between
13 rate cases create risks of undermining the cost recovery structure of
14 existing base rates that are designed to recover the rate base built
15 to serve the very loads that would migrate to a marginal cost or non-
16 firm service rate or program. It is premature to speculate further on
17 the impacts to the embedded utility system or the cost structure
18 supporting that system that would result from a shift in loads from a

[10] Duke witnesses Duff and Huber's Joint Testimony, p. 39.

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1 firm to a non-firm cost recovery structure. Ideally, such a review
2 would be conducted in advance of a general rate case where the
3 findings of that review are incorporated in the cost-of-service study
4 and rate design that would accompany a general rate case filing.
5 CIGFUR's concerns over the development of new flexible load
6 programs highlight the manner in which such costs would be
7 recovered.

8 Similar concerns existed around cost recovery of existing DSM
9 programs that were in effect at the time of the Companies' initial
10 DSM/EE mechanism in the late 2000's.[11] Ultimately, the Commission
11 decided that existing DSM programs for both DEC and DEP would
12 continue to be recovered in base rates. However, the Commission
13 concluded in its approval of the original DSM/EE mechanism for DEC
14 that the cost of new DSM programs would be recovered through the
15 new annual DSM/EE riders.[12] The same treatment of existing DSM
16 programs applies to DEP. DEC is still recovering the costs of those
17 pre-existing DSM programs through base rates in its Existing DSM

[11] See the Commission's Order Resolving Certain Issues, Requesting Information on Unsettled Matters, and Allowing Proposed Rider to Become Effective Subject to Refund, dated February 26, 2009, in Docket No. E-7, Sub 831.

[12] *Id*. at 10 (Finding of Fact No. 42).

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Program Cost Adjustment Rider and Bulk Power Marketing Rider. DEP does not have any pre-existing DSM programs that are currently being recovered through a rider. Should these new flexible load and demand response programs be implemented, the Commission must determine how the costs of these programs will be recovered, including whether they are designated as "DSM" as defined by N.C.G.S. § 62-133.8(a)(2).

The Public Staff's Initial Comments also discuss how the voluntary nature of DSM creates challenges with continued program potential.[13] DSM should be viewed in terms of "passive" and "active" programs.

The Public Staff views "passive" DSM as programs relying solely on customer behavior to shift loads from hours that are on-peak and/or higher cost, to hours that are off-peak and/or lower cost, including all time-of-use rate designs. Because of the uncertainty associated with passive DSM, the Companies will continue to plan and build resources to serve the load regardless of customer behavior and response, or their participation in these programs. Future DSM

[13] Public Staff Initial Comments, p. 61.

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1 programs could be designed to take into consideration a different
2 paradigm of customer participation and response.

3 The Public Staff considers "active" DSM to be programs that obligate
4 the customer to respond to direct signals from the Companies to shift
5 or eliminate loads, with assessment of customer penalties for failure
6 to respond. By being able to control the load associated with these
7 active DSM programs, the Companies may not need to proactively
8 plan and build resources to serve that load.

9 Both passive and active DSM programs are necessary for Carbon
10 Plan compliance, and the Public Staff is interested in new and
11 innovative approaches to providing customers with choices around
12 how they use energy. The Public Staff participated in the
13 Comprehensive Rate Design Study referenced by Duke witnesses
14 Duff and Huber[14] and is satisfied that there are ample opportunities
15 for new DSM programs. The Public Staff hopes that the issue of how

[14] Duke witnesses Duff and Huber's Joint Testimony, pp. 41-44.

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the costs of these programs will be recovered will not be a barrier to their adoption.

As discussed by Duke witnesses Duff and Huber throughout their Joint Testimony, new and expanded renewable generation programs and offerings provide opportunities for all customers to support the development and use of renewable generation. The Public Staff is supportive of such programs provided that incremental costs above a baseline of avoided cost incurred to provide these renewable programs are borne by the program participants. A thorough analysis of individual programs and the benefits to participants and the system as a whole is necessary to evaluate and allocate costs in a manner that maintains the principle of cost-causation. The testimony of Public Staff witness James S. McLawhorn addresses in more detail the cost-causation principles that are essential to fair and reasonable rates for all customers.

**Q. PLEASE EXPAND ON THE PUBLIC STAFF'S CONCERNS REGARDING THE COMPANIES' UEE FORECASTS.**

A. In its Initial Comments, the Public Staff expressed concerns with Duke's hard-coding in their modeling of an annual one percent

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energy reduction based on prior-year-available retail sales, bypassing DEC's and DEP's MPS, which I will discuss in Section II, below. In addition, the Public Staff raised a number of concerns involving the modeling used in Duke's UEE program forecasting, noting that the Companies have expressed a desire to see certain regulatory changes implemented in order to transform their EE portfolios to maximize the savings the Companies can "claim" as UEE for purposes of Carbon Plan compliance, and discussing the resulting unintended impacts on the DSM/EE Rider. I will discuss this issue in Section III, below.

## II. <u>The Companies' Proposal to Use One Percent of Prior-Year-Available Retail Sales as the Utility Energy Efficiency Forecast Assumption</u>

**Q. PLEASE DESCRIBE THE COMPANIES' ONE PERCENT OF PRIOR-YEAR-AVAILABLE RETAIL SALES FORECAST PROPOSAL.**

A. For many years, the Companies have had an aspirational goal of achieving energy savings of one percent of annual retail sales through their EE programs, a threshold that has served as an

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1 informal measure to define EE success.[15] The Companies have
2 traditionally relied upon, and the Commission has accepted, utility-
3 specific market potential studies to establish a benchmark for new
4 EE measures and savings in IRP proceedings. However, in this
5 proceeding, the Companies have instead applied a hard-coded
6 aspirational UEE savings target of one percent of prior-year-retail
7 sales as the modeling assumption in the UEE forecast, deviating
8 significantly from the Companies' use of achievable savings
9 projected in its MPS for measure/program development.[16] In
10 addition, Duke witnesses Duff and Huber propose the following
11 regulatory changes, which the Companies refer to as "enablers," and
12 which the Companies assert would enable DEC and DEP to achieve
13 the EE target: (1) updating the underlying determination of the utility
14 system benefits in the Companies' approved EE/DSM cost recovery

[15] See, e.g., "Next-Generation Energy Efficiency Resource Standards," published by the American Council for an Energy-Efficient Economy, *available at* https://www.aceee.org/sites/default/files/publications/researchreports/u1905.pdf (August 2009); and "The 2020 State Energy Efficiency Scorecard," published by the American Council for an Energy-Efficient Economy, *available at* https://www.aceee.org/sites/default/files/pdfs/u2011.pdf (December 2020).

[16] Attachment IV of the Proposed Carbon Plan lists the achievable potential for DEC and DEP in Tables 1-2 and 1-4, respectively.

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mechanisms (Mechanisms);[17] (2) moving to an "as found" baseline; and (3) expanding the pool of low-income customers.[18]

**Q. HAVE THE COMPANIES JUSTIFIED THEIR USE OF AN ANNUAL TARGET OF ONE PERCENT OF PRIOR-YEAR-AVAILABLE RETAIL SALES?**

A. No. The Companies have acknowledged that this target is aggressive but assert that it is achievable. Duke witnesses Duff and Huber state that:[19]

> The Companies believe that, after considering the historical level of achievements, the forecast of utility energy efficiency incorporated into the Companies' most recently approved Integrated Resource Plan ("IRP"), the performance targets built into the Companies' recently modified cost recovery Mechanism, and *the potential impact of some of the identified enablers included in the Carbon Plan*, the assumption of 1% of eligible load is appropriately aggressive yet achievable.

[17] The Companies' most recent Cost Recovery and Incentive Mechanisms for DSM/EE Programs were approved by the Commission's Order Approving Revisions to Demand-side Management and Energy Efficiency Cost Recovery Mechanism, issued on October 20, 2020, in Docket Nos. E-2, Sub 931 and E-7, Sub 1032.

[18] Specifically, Duke witnesses Duff and Huber request in their Joint Testimony that the Commission "acknowledge" that these changes will need to be made as enablers to achieving its one percent EE target, either in the Mechanisms or as separate program approvals. Duke witnesses Duff and Huber's Joint Testimony, pp. 7-8 and 49.

[19] Duke witnesses Duff and Huber's Joint Testimony, pp. 12-13.

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(Emphasis added).

In the Public Staff's view, the only way that the Companies can meet this one percent target is if Duke's proposed regulatory changes are approved by the Commission for planning purposes, which, as I will discuss in greater detail in Section III, below, is not my recommendation. As highlighted in its Initial Comments, the Public Staff is concerned that the Companies are advocating for a UEE forecast that is not based upon accepted practice and has not been approved in the DSM/EE rider proceedings, the Mechanisms, or recent IRPs.

The Public Staff's Initial Comments advocate that the Companies model the UEE forecast using their "low EE case assumption," which is based upon the Companies' most recent MPS. Duke witnesses Duff and Huber acknowledge that:

> the Companies' most recently approved IRPs included an amount of utility energy efficiency that was based on a Market Potential Study, performed by a third-party expert, *that sought to view energy efficiency investments through the lens of what is technically feasible, what makes economic sense, and what is likely achievable given market barriers*.

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1 (Emphasis added).[20]

2 The Companies have struggled in recent years to maintain or
3 increase cost-effective EE savings for some individual programs, as
4 well as the overall EE portfolio, because of a number of headwinds[21]
5 affecting EE program performance in the Companies' service
6 territory. Examples include:

7 • Updates to codes and appliance standards;
8 • Market transformation; and
9 • Decreasing avoided cost rates that have lowered the
10 economic value of EE benefits on a system basis.

11 These headwinds have spurred renewed dialogue around the
12 calculations and inputs related to cost-effectiveness, and the MPS
13 sought to recognize these headwinds in its study. Section 2.2 of the
14 Companies' MPS, titled "Methodology," and particularly Figure 2-2

[20] Duke witnesses Duff and Huber's Joint Testimony, p. 13.

[21] "Headwinds" in this instance are represented as utility-specific sensitivities that third-party evaluators apply to their evaluation to ensure that the unique characteristics of the utilities' service territory are considered. These headwinds are typically outside of the utility's control, but must be considered when developing and delivering cost-effective EE/DSM programs to its customers.

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1 and associated text,[22] provides a description of what the third-party
2 evaluator considers in determining the different levels of market
3 potential (e.g., technical, economic, achievable, and program).

4 Finally, Duke witnesses Duff and Huber discuss the one percent
5 target already in place as a financial reward within the
6 Mechanisms.[23] This one percent savings target was originally
7 incorporated into a stipulation approved by the Commission in 2013
8 between DEC, the Public Staff, North Carolina Sustainable Energy
9 Association, Environmental Defense Fund, Southern Alliance for
10 Clean Energy, Coastal Conservation League, and Natural Resource
11 Defense Council.[24]

12 While the Public Staff has never objected to the use of the one
13 percent savings target as a stretch goal for the Companies, it

[22] Proposed Carbon Plan, Attachment IV, pp. 20-23.

[23] Duke witnesses Duff and Huber's Joint Testimony, p. 14.

[24] See the Commission's Order Approving DSM/EE Programs and Stipulation of Settlement, dated October 29, 2013, in Docket No. E-7, Sub 1032. The one percent annual target included in this order originated from a settlement agreement between Environmental Defense Fund, Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, and DEC on December 8, 2011, in Docket Nos. 2011-158-E and 2011-68-E before the South Carolina Public Service Commission related to the merger of Duke Energy Corporation and Progress Energy, Inc.

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exceeds the achievable savings forecast by the MPS. The Companies should rely upon the most realistic and achievable energy savings assumptions to ensure that the load forecast, which ultimately drives statutorily mandated least cost resource planning decisions as discussed in the testimony of Public Staff witness McLawhorn, is as accurate and reasonable as possible. The differences between the Companies' MPS and the one percent target are illustrated in Figures 7 and 8 in the Public Staff's Initial Comments.[25] If the Companies rely upon a hard-coded target of one percent prior-year-retail sales EE savings, every megawatt-hour of energy not reduced as projected must be served in some form or fashion, and likely in a manner that is not least cost. Utilizing a realistic and achievable modeling approach, consistent with the approach accepted in IRP proceedings, provides greater assurance that the energy requirements and reliability needs of the grid are being reasonably addressed. The Public Staff agrees with Duke witnesses Duff and Huber that:

> Any overstatement of attainable energy efficiency savings results in an understatement of net load that must be served by supply-side resources. This

[25] Public Staff Initial Comments, p. 54.

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> understatement of load will lead the optimization model to under build new supply-side resources or retire existing resources prematurely, thereby compromising system reliability.[26]

While Section 110.9 directs the Commission to adopt a plan to reduce carbon emissions, it does not change any aspect of how UEE should be defined or modeled, or other policy decisions involving UEE. Nor does Section 110.9 alter the process for recovery of DSM/EE costs that has been approved pursuant to N.C.G.S. §§ 62-133.8 and 133.9. Indeed, Section 110.9(2) states that "[e]xisting law shall apply with respect to energy efficiency measures and demand-side management." Until the Commission rules upon the Companies' proposed regulatory changes discussed in Section III, below, which would change the methodology for counting DSM/EE savings and the calculation of cost-effectiveness; or until the North Carolina General Assembly enacts a law directing how UEE should be handled or modified, it is unreasonable to advocate for such aggressive targets that go well beyond what is considered achievable in the current MPS.

[26] Duke witnesses Duff and Huber's Joint Testimony, p. 18.

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1 **Q. WHAT IS YOUR RECOMMENDATION REGARDING THE**
2 **COMPANIES' REQUEST THAT ONE PERCENT OF ELIGIBLE**
3 **RETAIL LOAD BE DEEMED A REASONABLE AND PRUDENT**
4 **ASSUMPTION FOR PLANNING PURPOSES?**
5 A. The Public Staff recommends that the Commission find that the
6 Companies' one percent of eligible retail load modeling assumption
7 is not reasonable and prudent for purposes of modeling UEE. Duke's
8 direct testimony of witnesses Snider, McMurry, Quinto, and Kalemba
9 explains that the Companies have run a sensitivity in their
10 Supplemental Portfolio 5 (SP5) to demonstrate the impacts to the net
11 load forecast when using the MPS assumptions.[27] Based on the
12 results of the SP5 model run, and for the reasons explained above,
13 the Public Staff recommends that for future Carbon Plan
14 proceedings, the Commission order that the Companies use the
15 most recent MPS as the appropriate forecast assumption as the base
16 case for modeling the impacts of UEE in the Carbon Plan. The Public
17 Staff is open to consideration of incentivizing aspirational savings

[27] *See* Direct Testimony of Duke witnesses Snider, McMurry, Quinto, and Kalemba, at p. 73, line 16 – p. 74, line 9.

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targets in DSM/EE mechanisms or potentially as Performance Incentive Mechanisms in multi-year rate plans, but ratepayers could be harmed if forecasts are not based on what has already been found to be reasonably achievable.

## III. The Companies' Proposed Regulatory Changes

**Q. WITH REGARD TO THE COMPANIES' PROPOSED REGULATORY CHANGES (ENABLERS), DUKE WITNESSES DUFF AND HUBER STATED IN THEIR JOINT TESTIMONY THAT:**

> **THE FACT THAT THE COMPANIES IDENTIFIED POTENTIAL ENABLERS OF THE INCREASE [IN ENERGY EFFICIENCY ACHIEVEMENT IN THE PROPOSED CARBON PLAN] SHOULD HELP TO EASE THE PUBLIC STAFF'S CONCERNS [THAT THE ONE PERCENT TARGET IS A "FORMIDABLE RISK"], AS WELL AS THE FACT THAT THE LARGEST PORTION OF THE INCREASE IN THE ASSUMED EFFICIENCY OCCURS AFTER 2030.**

**ARE THE PUBLIC STAFF'S CONCERNS EASED BY THE COMPANIES' IDENTIFICATION OF POTENTIAL ENABLERS?**

A. No, they are not. As stated above, the Public Staff continues to be concerned with both the hard-coding of a one percent energy reduction based on prior-year-available sales, as well as how the

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Companies intend to transform the EE portfolio to maximize what the utilities can claim as UEE for purposes of Carbon Plan compliance.

In addition, the Public Staff is concerned with the potential for the Companies to receive financial rewards with Portfolio Performance Incentive (PPI), Program Return Incentive (PRI), and Net Lost Revenues (NLR) for energy reductions that do not originate from, or have exceeded the life of, the EE measures that comprise their DSM/EE portfolios. Not properly accounting for these energy savings for cost recovery purposes could result in a financial windfall to the Companies. It is unclear how the Companies' enablers would affect the cost recovery of DSM/EE. The Mechanisms require an approved process of review and modification rooted in preserving the integrity of the cost recovery, program approval, and modification processes, allowing the Companies a fair and reasonable recovery of program costs, incentives, and NLR. The Mechanisms have served as the means of complying with N.C.G.S. §§ 62-133.8 and 133.9, which encourage the implementation of DSM/EE and appropriate rewards to the Companies, and should serve as a foundation for complying with Section 110.9.

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**Q. DOES THE PUBLIC STAFF AGREE WITH DUKE'S PROPOSAL TO UPDATE THE INPUTS UNDERLYING THE DETERMINATION OF THE UTILITY SYSTEM BENEFITS AT THIS TIME?**

A. No. In the Proposed Carbon Plan, the Companies stated that:

> [T]he updated inputs utilized for justifying demand-side utility programs will be based on specific costs associated with the selected marginal carbon free and storage resources in the approved Carbon Plan added to the system energy and capacity, inclusive of transmission and other required infrastructure.[28]

In this Carbon Plan proceeding, the Companies have not proposed a preferred portfolio, nor has the Commission yet approved a plan that would use these assumptions. Until a Carbon Plan is adopted by the Commission, the Public Staff is unable to assess the reasonableness of using specific inputs within a particular portfolio as the foundation for determining the avoided cost benefits associated with UEE. While the load forecast is consistent across the modeled portfolios in the Proposed Carbon Plan, the generation technologies utilized to satisfy load requirements are not. No details around avoided cost benefits (avoided energy, avoided capacity, and avoided transmission and distribution) have been provided by the

[28] Proposed Carbon Plan, Appendix G, p. 12.

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Companies. The determination of avoided cost rates is essential to the valuation of benefits and cost-effectiveness of DSM/EE.

**Q. SHOULD AN UPDATE TO THE INPUTS UNDERLYING THE DETERMINATION OF THE UTILITY SYSTEM BENEFITS BE CONDUCTED WITHIN A FULL MECHANISM REVIEW?**

A. Yes. Duke witnesses Duff and Huber agree with the Public Staff that the types of changes proposed in their Joint Testimony necessitate a review of the Mechanisms. Additionally, in response to Public Staff discovery, the Companies acknowledge that they have yet to perform any analysis of the impacts of any changes they may propose to the Mechanisms, nor have the Companies identified any changes to specific inputs used to evaluate utility system benefits.

Moreover, any modification to individual components of the Mechanisms must take place in the context of a full, formal review of the entire Mechanisms, so that any impacts on other components of the Mechanisms can be analyzed at the same time. It is critical that the Commission ensure that financial rewards remain at levels that are fair to both customers and the Companies and are based upon appropriate sources of energy savings and calculations of benefits.

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1 Determining inputs to calculate avoided cost benefits also requires
2 an investigation regarding which benefits should be included in the
3 determination of cost-effectiveness. Under the current Mechanisms,
4 and since 2007, the Companies have used a traditional algorithm
5 based on the same framework described by the National Action Plan
6 for Energy Efficiency,[29] with only minor changes over the years. Over
7 the last several years and specifically during recent cost recovery
8 mechanism reviews, environmental advocates have begun
9 proposing the incorporation of some non-traditional, societal, and
10 non-energy benefits in the evaluation of EE savings. For instance,
11 the National Energy Screening Project published a "National
12 Standard Practice Manual for Benefit-Cost Analysis of Distributed
13 Energy Resources" in August of 2020, which incorporates a number
14 of additional system benefits, including non-energy benefits.[30] The
15 Public Staff supported the inclusion of a provision in the 2020

[29] See "Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers, Best Practices, Technical Methods, and Emerging Issues for Policy-Makers," published by the National Action Plan for Energy Efficiency, available at https://www.epa.gov/sites/default/files/2015-08/documents/cost-effectiveness.pdf (November 2008).

[30] This practice manual is available at https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/.

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1 Mechanism revisions[31] that allows the use of non-energy benefits, as
2 approved by the Commission. However, Section 110.9's requirement
3 that the Commission approve a carbon reduction plan warrants
4 additional analysis of these non-energy benefits. Based upon the
5 potential impact to the Mechanisms, the Public Staff recommends
6 that the Commission require a comprehensive review of the
7 Mechanisms that would allow all interested parties an opportunity to
8 discuss, among other things, the potential changes to the underlying
9 determination of the utility system benefits based on the Carbon Plan
10 approved by the Commission, issues related to avoided cost
11 calculations, market potential of EE, the appropriate PPI and PRI,
12 and changes to the determination of cost effectiveness.

13 **Q. WHAT IS THE PUBLIC STAFF'S POSITION ON CALCULATING**
14 **EE SAVINGS USING "AS FOUND" SAVINGS?**

15 A. The Proposed Carbon Plan briefly explains the Companies'
16 proposed "as found" baseline methodology.[32] The Companies'
17 methodology uses the efficiency of existing equipment that is

[31] *See* n.16, supra.

[32] Proposed Carbon Plan, Appendix G, p. 13.

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1 replaced as the baseline to calculate energy savings assigned to the
2 new EE measure, as opposed to the more traditional use of
3 incremental energy savings resulting from a comparison of the
4 energy consumption of the new equipment with industry and building
5 code minimum efficiency standards. The Companies' proposal
6 assigns the difference between the energy consumption of the
7 equipment being replaced and the energy consumption of the new
8 EE equipment being installed as "energy savings" eligible for cost
9 recovery under the Mechanisms. The Companies' "as found" energy
10 savings incorporates both naturally occurring EE savings[33] and the
11 incremental EE savings that are above equipment baselines or
12 standards.

13 While the Public Staff does not object to the Companies claiming
14 naturally occurring savings for purposes of Carbon Plan compliance,
15 it does object to counting these same energy savings for DSM/EE
16 cost recovery purposes. A full and comprehensive review of the

[33] The Public Staff describes "naturally-occurring" EE savings as those energy savings that happen outside of utility-sponsored EE programs, including any energy savings realized by customers who adopt EE measures on their own, EE savings associated with industrial opt-out customers, free riders, and any other form of EE that occurs without the influence of the Companies' EE efforts.

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DSM/EE Mechanisms must occur before claiming these same energy savings as part of DSM/EE cost recovery, including financial rewards.

Further, the Companies' "as found" baseline methodology is not appropriate for any EE measure with an identified baseline efficiency. While the Companies' current EE portfolios include some measures that have employed the Companies' "as found" baseline methodology, this approach has generally been used to address measure installations that are custom or unique and do not have codes or standards upon which to base savings. The evaluation, measurement, and verification associated with such measures has been accepted as complete by the Commission. Going forward, however, it is appropriate to identify the methodology to be used by the Companies to measure EE savings at the time of program approval or modification.

In addition, under the new construct of performance-based regulation (PBR), the Companies should not receive credit for naturally occurring EE savings of residential customers as a result of switching to an "as found" baseline methodology, while also

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recouping fixed cost recovery erosion through the residential decoupling mechanism that will be part of future PBR/general rate case applications. Decoupling, which includes naturally occurring EE savings, creates the potential for double counting between the DSM/EE rider proceedings' NLR calculations and the residential revenue decoupling mechanism in a PBR application. It is unclear at this time how the Commission will treat these naturally occurring EE savings in a PBR proceeding.

Therefore, the Public Staff recommends that the Commission distinguish the energy savings that can be used for DSM/EE cost recovery purposes from those savings that are used for Carbon Plan compliance purposes. The Public Staff also recommends that, if the Companies' "as found" methodology is approved for Carbon Plan compliance purposes, the Commission hold in abeyance the use of such methodology for cost recovery purposes until a full and comprehensive DSM/EE mechanism review takes place. In the meantime, the Public Staff recommends that, for any program approval or modification filed before the next mechanism reviews, the Companies identify which methodology (traditional baseline or

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1 "as found") the respective company intends to apply to each measure
2 included in the program.

3 **Q. PLEASE DISCUSS THE PROPOSAL TO EXPAND THE POOL OF**
4 **LOW-INCOME PARTICIPANTS.**

5 A. The Companies have requested to expand the definition of eligible
6 "low-income" customers to include those with income levels up to
7 300% of the federal poverty guidelines (FPG).[34] Specifically, the
8 Companies have stated that the 300% "low-income" definition
9 expansion is to support customers who have a significant or
10 disproportionate energy burden or energy intensity, but who currently
11 do not qualify based on existing definitions of income-qualified
12 customers.[35]

13 In the Companies' 2019 rate cases, the Commission established the
14 Low Income Affordability Collaborative (LIAC) and directed Duke, the
15 Public Staff, and interested stakeholders (members) to address the

[34] Proposed Carbon Plan, Appendix G, pp. 9-10; and Duke witnesses Duff and Huber's Joint Testimony, pp. 31-32.

[35] Proposed Carbon Plan, Appendix G, p. 10.

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1 affordability of electric service for low-income customers.[36] On
2 August 12, 2022, the Joint North Carolina LIAC Quarterly Progress
3 Report was filed (LIAC Final Report),[37] indicating that the consensus
4 of stakeholders was that "low-income" should be defined as
5 residential customers with gross household incomes that are less
6 than 200% FPG. In arriving at this decision, the LIAC members
7 discussed other terms such as "low-moderate income," "moderate-
8 income," "upper-income," and "higher-income," and ultimately
9 determined that less than 200% FPG provided a clear delineation
10 between "low-income" and "non-low-income."

[36] Commission's Orders Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice, dated March 31, 2021, in Docket Nos. E-7, Subs 1213, 1214, and 1187; and dated April 16, 2021, in Docket Nos. E-2, Subs 1219 and 1193.

[37] Docket Nos. E-2, Subs 1219 and 1193 and E-7, Subs 1213, 1214, and 1187.

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1 The data analytics utilized in the LIAC Final Report[38] evaluated four
2 income-based customer segments:[39] (1) Low-Income Energy
3 Assistance Program or Crisis Intervention Program (LIEAP/CIP)
4 recipients; (2) residential customers with gross household incomes
5 that are less than 150% FPG; (3) residential customers with gross
6 household incomes that are 150% to 200% FPG; and (4) residential
7 customers with gross household incomes that are greater than 200%
8 FPG. However, for clarity amongst the stakeholders, the statistical
9 modeling[40] used in the data analytics throughout the LIAC Final
10 Report only evaluated residential customers with gross household
11 incomes that are less than 200% FPG, which ensured that the
12 discussions undertaken within the LIAC were based upon residential
13 customers who qualify for the Companies' low-income programs.

[38] LIAC Final Report, Appendix C; Data Analytics Version 4 was the final version and was published in March 2022.

[39] LIAC Final Report, Appendix C, p. 12. In its Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice, entered on March 31, 2021, in Docket Nos. E-7, Subs 1213, 1214, and 1187, the Commission ordered that the LIAC evaluate the following customer segments: residential customers with household incomes that are at or less than 150% FPG, and residential customers with household incomes that are at or less than 200% FPG. The LIAC's evaluation of additional customer segments was undertaken at the LIAC's own initiative.

[40] LIAC Final Report, Appendix C, pp. 24-29.

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1 The LIAC Final Report stated that 898,448 of the Companies'
2 residential customers met the 200% FPG "low-income" definition,
3 representing 29% of the Companies' 3.07 million total residential
4 customers.[41]

5 The LIAC Final Report, when taking into consideration all attribute
6 impacts,[42] revealed a general pattern showing that, as income levels
7 increased across the customer segments, the attribute impacts
8 decreased.[43] The LIAC Final Report's Average Electricity Burden
9 Income and Arrearage Definition slide[44] demonstrates this pattern,
10 with LIEAP/CIP recipients having the highest energy burden, and
11 progressively decreasing for customer segments less than 150%
12 FPG, 150 to 200% FPG, and greater than 200% FPG, respectively.
13 This shows that customers that currently qualify as "low-income" are
14 an appropriate group to focus on regarding affordability challenges.

---

[41] *Id*. at 10.

[42] The Data Analytics Version 4 analyzed the four income-based customer segments against 13 numerical and categorical Attributes. Energy Burden is one of those attributes. See LIAC Final Report, Appendix C, p. 25, for the list of those attributes.

[43] LIAC Final Report, Appendix C, p. 20. This general pattern is seen across all attributes.

[44] *Id*.

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The Companies provide little explanation for the proposed change to the definition of "low-income" recently recommended by the LIAC, other than stating that the Companies' request was being made in addition to, and not coinciding with, the process that LIAC stakeholders relied upon to produce their final report.

**Q. DID THE LIAC CONSIDER INCREASING THE THRESHOLD OF WHAT SHOULD BE CONSIDERED LOW-INCOME?**

A. Yes, the LIAC did consider increasing the threshold for defining "low-income." However, stakeholders rejected an increased threshold because it encompassed too many customers. One of the primary reasons stakeholders expressed for rejecting the expansion of the qualification was the increasing costs and potential for cross-subsidy that would accompany any expanded assistance program. Another reason was the desire of stakeholders to focus any mitigation efforts on those who were most vulnerable to falling behind on their bills and risking disconnection.

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1 Currently, DEC has a pending Residential Income-Qualified High
2 Energy Use pilot application.[45] This application is a direct result of
3 the recent LIAC and EE stakeholder processes, where eligibility is
4 based, among other things, upon the 200% FPG "low-income"
5 definition.

6 **Q. DOES THE PUBLIC STAFF SUPPORT EXPANDING THE**
7 **DEFINITION OF "LOW-INCOME" TO INCLUDE THOSE WHO**
8 **HAVE HOUSEHOLD INCOMES UP TO 300% FPG?**

9 A. No. For the reasons stated above, the Public Staff does not support
10 expanding the definition of "low income" beyond those customers
11 who have household incomes above 200%. It is not at all clear that
12 this change would increase the EE savings potential of the
13 Companies. Under the current Mechanisms, low-income programs
14 are not required to meet certain cost-effectiveness requirements.
15 The Companies are also allowed to earn utility incentives (PRI),
16 which incentivize making EE programs more cost-effective.

[45] Docket No. E-7, Sub 1272.

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The Public Staff notes that, typically, low-income programs are not cost-effective as they are designed to be delivered at no, or very low, cost to the participant. Participants in low-income programs benefit from reduced bills, but all customers bear the costs of programs that are not cost-effective and would do so to an even greater extent if eligibility were broadened. The current annual residential DSM/EE rider amounts[46] are $57.24 per year for DEC and $86.52 per year for DEP, including for low-income customers.[47] Instead of increasing participation by changing the eligibility requirements, the Companies should increase participation by: (1) better targeting its programs to the customers most in need by using information such as that provided by the LIAC; and (2) lowering costs and increasing benefits to all customers by increasing the cost-effectiveness of its low-income programs.

**Q. DOES THE PUBLIC STAFF HAVE ANY RECOMMENDATIONS REGARDING THE COMPANIES' REQUEST TO EXPAND THE POOL OF LOW-INCOME CUSTOMERS?**

[46] E-7, Sub 1249 and E-2, Sub 1273.

[47] These costs are based upon projections of 12,000 kWh per year or 1,000 kWh per month.

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1 A. Yes. The Public Staff recommends that the Companies work to
2 implement potential cost-effective programs based on the work of the
3 LIAC before requesting to expand the pool of customers. The focus
4 should be on providing greater opportunities for the low-income
5 customers who have the greatest needs and better targeting those
6 opportunities to increase the level of participation of low-income
7 customers.[48] Since the LIAC Final Report was filed after the
8 Companies filed their Proposed Carbon Plan, but before the filing of
9 the Companies' direct testimony, it is unclear what influence the LIAC
10 Final Report had on the modeling and proposals contained within the
11 Proposed Carbon Plan.

12 **Q. DO ANY INTERVENORS IN THIS CARBON PLAN PROCEEDING**
13 **TAKE ISSUE WITH THE COMPANIES' APPROACH TO**
14 **AFFORDABILITY AND LOW-INCOME CUSTOMERS?**

15 A. Yes. The Initial Comments of Appalachian Voices ask the following
16 question: "[w]ill the Companies' failure to address energy affordability

[48] According to the LIAC Final Report, approximately 33% of the Companies' North Carolina residential customers are eligible for the Neighborhood Energy Saver Program. Since this Program's inception, only 7.8% and 10% of eligible DEC and DEP customers, respectively, have participated in the program. LIAC Final Report, p. 25.

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through targeted energy efficiency, distributed energy and demand response investments increase total energy costs and increase energy burdens for all customers?"[49]

The LIAC Final Report identified groups of under-served customers and customers that are in the greatest need of assistance. Affordability issues are typically not part of an IRP proceeding and were not specifically addressed by the Companies in their Proposed Carbon Plan. However, House Bill 951 also allows the Commission, in a PBR proceeding, to consider whether a PBR application lowers energy burdens, and requires the Commission to consider whether a PBR application would result in rate shock.[50] These issues must be discussed contemporaneously to ensure that the requirements contained within Sections 110.9 and 133.16 are being satisfied.

**Q. IS IT APPROPRIATE OR NECESSARY FOR THE COMMISSION TO ACKNOWLEDGE, AT THIS TIME, THAT THE ENABLERS IDENTIFIED BY THE COMPANIES ARE NECESSARY TO ACHIEVE TARGETED ENERGY EFFICIENCY SAVINGS?**

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[49] *See* Appalachian Voices' Initial Comments, Attachment D.

[50] *See* N.C.G.S. § 62-133.16(d).

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A. No, it is not. As discussed in detail above, as well as in its Initial Comments,[51] the Public Staff believes that acceptance of the Companies' identified enablers requires either public policy decisions by the Commission, legislative action, or a proceeding separate from this docket to investigate the impacts of any proposed enablers. Section 110.9 contains very specific carbon reduction goals, but aside from certain generation technologies, the law does not prescribe the means by which to achieve these goals.

## IV. <u>The Companies' Proposed Flexibility and Rapid Prototyping Guidelines</u>

**Q. DO YOU BELIEVE IT IS APPROPRIATE OR NECESSARY FOR THE COMMISSION TO ACKNOWLEDGE, AT THIS TIME, THAT AN EXPEDITED REGULATORY PROCESS FOR NEW PILOT PROGRAMS IS NEEDED, AS REQUESTED BY THE COMPANIES?**

A. No, I do not. In its testimony, the Companies point out that other states have implemented such expeditious methods that may be warranted in North Carolina. Additionally, the Companies describe

[51] Public Staff Initial Comments, p. 52.

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1 an expeditious method that is already in place for more streamlined
2 minor modifications to existing DSM/EE programs, known as the
3 Flexibility Guidelines.[52]

4 The Flexibility Guidelines were developed following consideration of
5 the amount of notice parties should receive of modifications to
6 DSM/EE measures or programs based on the modifications' impacts
7 on cost-effectiveness, costs, and savings. The Flexibility Guidelines
8 cover both major and minor modifications of existing DSM/EE
9 programs, expediting minor modifications that otherwise do not
10 require a change in tariff language in response to technology
11 changes, and requiring prior notice and Commission approval for
12 more major modifications.

13 The Companies may propose new methodologies in the appropriate
14 forum, but the Public Staff disagrees that: (1) the Commission needs
15 to acknowledge a need for expedited review in this Carbon Plan
16 proceeding; and (2) the Companies need to develop an expedited

[52] DEC's Flexibility Guidelines were developed and filed with the Commission on February 6, 2012, in Docket No. E-7, Sub 831, and were approved on July 16, 2012. DEP's Flexibility Guidelines were approved on January 20, 2015, in Docket No. E-2, Sub 931.

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review process for new programs and rate designs related to the Carbon Plan at this time.

Allowing the Company to introduce new DSM/EE pilots, DSM/EE programs, and rate designs without a full review will jeopardize the Commission's ability to ensure that the pilots are reasonable and prudent before costs are incurred and that the pilots are being pursued in a manner that aligns with state policy, laws, and Commission rules.

In light of the fact that no specific proposal is before the Commission at this time, the Public Staff recommends that the Commission deny the Companies' additional flexibility request in this Carbon Plan proceeding. The Public Staff has worked with the Companies in the past to develop a reasonable process for pilot program approval, and is committed to doing so in the future. As an initial step, the Public Staff will look to the guidelines for scale and scope of pilots that were approved in the Commission's Order Approving Electric Transportation Pilot, In Part, dated November 24, 2020, in Docket Nos. E-2, Sub 1197 and E-7, Sub 1195. Further, this additional flexibility, with respect to DSM/EE pilots, would be an appropriate

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1 topic for discussion in a comprehensive review of the currently
2 approved Mechanisms.

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

4 A. Yes, it does.

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## APPENDIX A

## QUALIFICATIONS AND EXPERIENCE

DAVID M. WILLIAMSON

I am a 2014 graduate of North Carolina State University with a Bachelor of Science Degree in Electrical Engineering. I began my employment with the Public Staff's Electric Division in March of 2015. In August of 2020, the Electric Division merged with the Natural Gas Division to form the Energy Division, where I am a part of the Electric Section – Rates and Energy Services. My current responsibilities include reviewing applications; making recommendations for certificates of public convenience and necessity of small power producers, master meters, and resale of electric service; and interpreting and applying utility service rules and regulations.

My primary responsibility within the Public Staff is reviewing and making recommendations on DSM/EE filings for initial program approval, program modifications, EM&V evaluations, and on-going program performance of Electric and Natural Gas' portfolio of EE programs. I have filed testimony in various DEC, DEP, and DENC Demand-Side Management/Energy Efficiency rider proceedings, as well as recent Electric and Natural Gas general rate case proceedings.

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**The Public Staff – North Carolina Utilities Commission**
**Summary of the Testimony of David M. Williamson**
**Docket No. E-100, Sub 179**

My testimony supports the Public Staff's Initial Comments filed in this docket on July 15, 2022, and provides additional explanation on its investigation into Duke's Proposed Carbon Plan. I also address intervenor comments on a wide range of issues within the Demand-Side Management (DSM)/Energy Efficiency (EE) and Grid Edge topics identified for the evidentiary hearing track. I provide several recommendations to the Commission regarding issues within the DSM/EE and Grid Edge topics.

First, I discuss the components of the Companies' Grid Edge initiatives and the individual forecasts that were used to create the net load forecast for the Proposed Carbon Plan. While I do not take issue with most of the forecasts for the components that comprise the Grid Edge initiatives, I do take issue with certain aspects of how the Companies have modeled their Utility Energy Efficiency (UEE) forecast. These changes in modeling assumptions, along with other regulatory requests made by the Companies, impact the overall net load forecast used in Duke's Proposed Carbon Plan filing and have the potential to create unintended impacts for the Companies' DSM/EE riders going forward.

Second, I discuss the Companies' incorporation of modeling assumption for its UEE forecast of one percent of prior-year-available retail sales. The Companies have stated on numerous occasions that this one percent target is an aggressive, but achievable target. However, this proposed modeling assumption deviates from

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past application and development of the Companies' UEE forecasts used in their Integrated Resource Plan (IRP) filings. Past IRP filings have used the Companies' most recent DSM/EE Market Potential Study (MPS) to determine the most reasonable assumptions regarding the implementation of the Companies' DSM/EE programs. Utilizing the MPS as a realistic guide for the UEE forecast ensures that supply-side resource planning in the near and distant future can be as realistic as possible. This approach has been an accepted practice in previous IRP proceedings and should continue to serve and provide the same level of confidence in these Carbon Plan proceedings. Accordingly, I recommend that the Commission find that the Companies' use of a one percent prior-year-available retail sales assumption is not reasonable and prudent for planning purposes. Instead, I recommend the use of the achievable potential from Companies' most recent MPS as the modeling assumption to be incorporated into the Commission's Carbon Plan in future Carbon Plan update proceedings.

Third, I discuss the Companies' request for acknowledgement of several regulatory changes that the Companies have identified as "enablers" to achieve their targeted one percent of prior-year-available retail sales. The Companies have proposed several enablers to DSM/EE programs, namely to: modify how avoided cost determinations are derived; apply an "as found" baseline methodology to new measure installations; and expand the current pool of eligible low-income customers to include residential customers with gross household incomes of up to 300% of the federal poverty guidelines. While the Companies have not performed any analysis on the impacts these changes would have on the portfolios in Duke's

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Proposed Carbon Plan, the Companies have stated that these enablers are part of their reasoning that the one percent of prior-year-available retail sales target is achievable. These enablers would maximize the amount of savings that the Companies can claim as UEE for purposes of Carbon Plan compliance, which will have unintended impacts on the Companies' DSM/EE rider proceedings. Without a full review of the currently approved DSM/EE cost recovery mechanisms, the Public Staff and the Commission will not be able to evaluate how these changes will impact the financial incentives that the Companies are allowed to recover in their DSM/EE riders. As such, I do not recommend that the Commission approve the regulatory changes sought by the Companies at this time, and instead I defer these conversations to the next full review of the Companies' DSM/EE cost recovery mechanisms.

Finally, I discuss Duke's request that the Commission acknowledge that a proposal for additional flexibility and rapid prototyping guidelines for DSM/EE pilots and rate designs is reasonable for future proceedings. Because no specific proposals were filed in the current proceeding, I recommend that the Commission deny this request.

This concludes my summary.

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MS. LUHR: The panel is available for cross-examination.

CHAIR MITCHELL: Avangrid?

MR. SMITH: Madam Chair, Mr. Buffkin requested, due to his wife's pending --

CHAIR MITCHELL: I'm sorry, Mr. Buffkin, I'm sorry. I knew that and I apologize.

MR. BUFFKIN: Thank you, Madam Chair, and my appreciation to the parties who've been able to accommodate us.

CROSS EXAMINATION BY MR. BUFFKIN:

Q. Good afternoon, gentlemen. I'm Patrick Buffkin representing Kingfisher Energy Holdings. Mr. Thomas, I think most of my questions are for you, but if the other members of the panel want to offer opinions or answers, please feel free.

So let me direct your attention to page 51, 52 of your testimony, where you testified that the Public Staff believes that all source of procurement should be utilized to procure resources identified in the approved Carbon Plan; is that right?

A. (Jeff Thomas) Yes. Although, I'll note that, on the following page, I do discuss some potential limitations to that provision identified by

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the NERP report that correspond to future legislation or regulatory changes that would require the procurement of additional renewable or low-cost carbon to comply with particular policy mandates.

Q. Thank you. And I'll return to that subject in just a minute. But let me ask you this.

Is it also your opinion that procurement of resources needed under the Carbon Plan through PPAs would facilitate lower cost and lower risk resource procurement than utility-owned assets?

A. I believe that the question of utility ownership is specified in 951, and I do believe, and I stated on page 50, that PPAs could facilitate lower cost and lower risk resource procurement.

Q. Okay. Thank you. And I saw your comments file, and I understand the Public Staff's position on that, but can you help reconcile what seemed to be contradictory positions that factually competitive procurement produces the least cost and least risk pathway to compliance with the Carbon Plan goals, but the Public Staff believes it's not allowed? So can you reconcile those two positions?

MS. LUHR: Objection. These are legal opinions that are laid out in our comments filed

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1 September 9th.
2 MR. BUFFKIN: Madam Chair, the
3 question's about Public Staff's policy development
4 and the factual assertion that competitive
5 procurement is the least cost.
6 CHAIR MITCHELL: All right. To the
7 extent that you're asking for factual information
8 underlying the Public Staff's position, I'll let
9 the question proceed and I'll overrule the
10 objection. But stick to the -- stick to the
11 factual information underlying the Public Staff
12 position.
13 THE WITNESS: So I think least cost is
14 implicitly least cost subject to existing
15 regulations and statutes. And to the extent that
16 the utility ownership of particular assets is
17 required by 951, that would be a statutory
18 requirement that least cost would be subject to.
19 But, obviously, the Public Staff is looking to the
20 Commission for guidance on the interpretation of
21 951 as it relates to PPAs.
22 Q. Fair enough. So we agree, then, that the
23 Commission has a decision to make on what the law
24 means?

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A. I believe so, yes.

Q. Okay. So then how does the Public Staff find assurances that the ratepayers are provided the benefits of a least-cost path required under House Bill 951 without a competitive procurement process?

A. So I think the competitive procurement process, you know, obviously the solar resources, solar plus storage, wind resources, I mean, those we expect to be competitively procured. We have an ongoing solar RFP that competitively procures that particular resource at least cost, which can provide ratepayer protections.

But I'll repeat, for other resources that are not specifically identified in 951, the question of whether a PPA is permitable -- permissible is a matter for the Commission to provide guidance on. And whatever the Commission's guidance there, we would make sure that that guidance is followed and that the least costs are obtained by the ratepayers subject to Commission guidance and 951 statute.

Q. Okay. So if there was a reasonable interpretation and the Commission decided that competitive procurement was allowed for those resources not specifically specified that you just mentioned,

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then would it be your recommendation that the Commission pursue competitive procurement for implementation in the Carbon Plan?

A. Yes. If the Commission ruled that certain resources could be procured through PPAs as some intervenors have argued, then yes, we would support those competitive procurements and would likely also oppose things such as a rate of return on PPA costs and other cost recovery issues. So we'd have to review that to ensure that the way the costs are recovered are still gonna be a least cost for the ratepayer.

Q. Okay. So just to summarize, absent a legal constraint, it would be your recommendation to use competitive procurement for getting new resources needed under the Carbon Plan?

A. Yes. If the Commission says that the PPAs are permissible, then yes, we would want those to be considered in the least-cost plan.

Q. Thank you, Mr. Thomas.

MR. BUFFKIN: Madam Chair, we have no further questions.

CHAIR MITCHELL: Okay. Avangrid?

CROSS EXAMINATION BY MR. SMITH:

Q. Good afternoon. Ben Smith representing

Avangrid Renewables. Mr. Buffkin's questions were helpful for me. I'm gonna start with Mr. Metz.

Can you turn to page 24 of your direct testimony, beginning at the end of line 2?

A. (Dustin Metz) Page 24 beginning at line 2?

Q. Yes. You state that offshore wind is expected to take approximately a decade at a minimum to achieve commercial operation depending on the size of facility and the infrastructure requirements; isn't that right?

A. That's correct.

Q. And then you state that supplemental model portfolios SP5 and SP6 do not select offshore wind in the next 10 years, but instead select it after 2040; isn't that right?

A. That's correct.

Q. And you recommend that the Commission deny Duke's request to begin a near-term resource development activities for offshore wind; isn't that right?

A. That's correct. And that's linkage back to their request for the long-lead development items for the Carolina Long Bay project.

Q. Thank you. And further down on lines 12 and

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16, I believe on the same page -- yes, also on page 24, you state that you do, however, recommend that Duke re-evaluate the need for offshore wind resources in the 2024 Carbon Plan, at which time the Commission can re-evaluate approval of near-term resources; isn't that right?

A. That is correct.

Q. Can you turn now to page 21 of your direct testimony.

A. (Witness complies.)

Page 21?

Q. Yes, sir. And this is on -- this is -- lines 4 to 13 is where this is located. In response to the question, "Should the Commission consider allowing any near-term resource development activities in the 2022 Carbon Plan," you state beginning on line 8, excuse me, "It is reasonable for Duke to perform further near-term evaluation to refine the timeline of commercial operations, identify risk factors, and determine more accurate cost estimates. However, North Carolina retail customers should only be responsible for the applicable percentage of reasonable and prudently incurred development costs."

Did I restate your testimony accurately?

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A. I just want to give context to the sentence, giving the modeling results and the long development time for both SMRs in Bad Creek II is reasonable for Duke to perform the near-term activities and the rest that you read into the record.

Q. Thank you. So is it fair to say that your recommendation to the Commission to deny Duke's proposed near-term development activities related to offshore wind is driven by cost?

A. I would say it's a function overall of the modeling results which, in part, is due to the cost.

Q. Thank you. Can you turn to page 17 of your direct testimony, beginning on line 10?

A. Page 17, line 10?

Q. Excuse me one second. Actually, would you mind scratching that question, I apologize.

Moving on to the next question, would you agree that an offshore wind study process could enable the collection of sufficient data on project characteristics, risks, permitting status, projected costs, and scheduled development to alleviate some of the concerns in your testimony?

A. I guess I'm hung up a little bit on the word phrase "study," I mean, because a study can be a very

expansive term.

Q. What would you look for in a study that could alleviate these concerns?

A. As a point of clarification, so in reference to Duke Energy's proposed long lead item 4, the Carolina Long Bay project, given the modeling results, it's just -- it's premature at this time to move forward with the overall project, given the potential unknowns for locational guidance, sustained wind speed, capacity factors, cable routing, potential paths. Give me a few more minutes and I'll probably come up with a bunch more.

Q. But all those things would be informative in a study?

A. Yes.

Q. Thank you. And so is it fair to say that, in order to increase certainty by the 2024 Carbon Plan proceeding, a study process, including some of the characteristics that you described but not all of the three offshore lease areas would be appropriate?

A. Can you please give me context of the three wind -- the three locations that you're specifying?

Q. Sure thing. The three offshore wind lease areas off the cost of the North Carolina including

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Kitty Hawk and the two Carolina Long Bay lease areas.

A. Okay. Thank you. So I want to be careful in the context of the word "study," that as I'm here today, I'm not advocating that for potential SAP in terms of defining the definitive amount that would inform the study. But I do believe that more due diligence could be completed to address some of the concerns that I outlined just earlier.

Q. Thank you. And would you agree that such due diligence conducted prior to Duke regulated and purchasing an offshore wind lease area would provide the Commission a higher degree of certainty as to least-cost compliance with HB 591?

A. I didn't understand that. Could you please repeat?

Q. Sure. You just referenced due diligence that could be done prior to moving forward with an offshore wind lease area, correct?

A. Correct.

Q. And wouldn't you agree that the due diligence that you referenced, conducted prior to Duke regulated purchasing an offshore wind lease area, could provide the Commission a higher degree of certainty as to least-cost compliance with HB 951?

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A. Correct.

Q. Thank you. Mr. Thomas, going to you. And I'm gonna try and skip all of the questions, because there are overlaps. Apologies.

So understanding that we didn't come to an exact agreement on what a study or due diligence might look like, would you agree that a study or due diligence could be helpful in assessing the three offshore wind sites: Kitty Hawk, Carolina Long Bay, and Carolina Long Bay -- the two different Carolina Long Bay areas?

A. (Jeff Thomas) Are you speaking in reference to the 2024 Carbon Plan or the Commission's decision in this docket?

Q. 2024 Carbon Plan.

A. So offshore wind is a little complicated in the modeling. Normally, resource selection in the IRP in the modeling is not site specific, but with the three discrete sites, some of which have different characteristics, I do believe that it would be a value in the 2024 Carbon Plan to look at all three of those sites. But that's obviously subject to whether or not a PPA is allowable and other off-take arrangements that might be organized there.

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Q. Yeah, I'm setting aside the ownership question and all those legal requirements, at least for right now. I might come back to that in just a minute.

You talked to Mr. Buffkin about competitive procurement. I want to know your thoughts as to whether a study or due diligence, under whatever definition the Public Staff is comfortable with, would align in some way with some of the principles of what you find helpful about competitive procurement?

A. Yeah. I think, to the extent that a competitive procurement requires sufficient information to evaluate the potential options for the least cost, more information is better. But, obviously, as witness Metz talked about, we need to understand what that study is, right? Do we require a full SAP to be submitted or is additional high-level estimates valid for such a comparison.

You know, and obviously, just comparing the resource characteristics may not be an accurate representation of the cost that might be if those were to lead to some sort of competitive solicitation for offshore wind. But I think it's complicated, those RFP terms, how they're defined, what type of transfer arrangements are built into the RFPs or potential

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ownership transfers.

So I think all that has to be taken into account. But certainly more information, to an extent, is better in evaluating those three options.

Q. Thank you. I'm gonna move on, because I think Mr. Buffkin covered most of my questions on this topic. I have a couple questions regarding your view of Duke's modeling related to onshore wind. Can you turn to pages 50 to 51 of your testimony?

A. (Witness complies.)

I'm there.

Q. You note that, quote, Duke may have inconsistently applied the utility ownership provisions of Section 110-9, sub 2 with regard to onshore wind resources.

Did I state that correctly?

A. Yes.

Q. And you go on to say that Duke's model, quote, onshore wind is assumed to be utility owned in DEP's territory and imported through PPA's in DEC's territory, either from PJM, the Midwest, or Texas.

Did I say that right?

A. Yeah, that's what it says.

Q. And finally you say, on page 51 of your

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testimony, "Duke could have made the modeling choice to simply prohibit the selection of onshore wind in DEC's utility territory" -- I'm sorry, excuse me -- "In DEC's territory as utility-owned assets could not be constructed."

Yet Duke made the decision that it is permissible to model these resources as a PPA; isn't that right?

A. Yes.

Q. And is it your understanding that, subsequent to your testimony, Duke has taken a different position on onshore wind ownership?

A. I'm not sure what position you're speaking of.

Q. Okay. Then I have no further questions.

CHAIR MITCHELL: All right. CCEBA?

MR. BURNS: Yes, ma'am.

CROSS EXAMINATION BY MR. BURNS:

Q. Good afternoon, gentlemen. I know most of you, I think. My name is John Burns, general counsel for CCEBA. I've just got a few questions for you.

Mr. Williamson, I understand your testimony to be primarily aimed at Grid Edge and EE and regulatory changes proposed by the Companies; is that

correct?

A. (David Williamson) That's correct.

Q. I don't want to suggest you leave the room and go get a Coke, but most of my questions are gonna be directed at your colleagues there. So primarily solar and storage and SMRs guys.

So, Mr. Thomas and Mr. Metz, in evaluating the Carbon Plan's modeling of solar and storage, the Public Staff had concerns with the way in which Duke Energy had modeled the performance and dispatch of solar plus storage, didn't you?

A. (Jeff Thomas) That's correct. And SP5 and SP6 attempted to address this deficiency.

Q. You jumped to one of my questions. I appreciate that.

A. Trying to save time.

Q. Could you briefly explain what those concerns that the Public Staff had were with the modeling?

A. Sure. So Duke used -- Duke modeled solar plus storage in EnCompass, which is normally two resources, solar and -- with a fixed output profile, and storage which can be dispatched. Modeled that as a single solar resource with a fixed output profile that was determined outside of EnCompass.

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And essentially they use an economic dispatch model that looked at pricing periods from the Sub 167, similar to Sub 158, avoided cost proceeding. I think they were actually the Sub 167 rate design, and they optimized revenue over a period of time to come up with these solar output profiles.

Generally, they, you know, would discharge, say, during winter morning or charge during peak, but that was held constant throughout the entire modeling period through 2050, so it didn't reflect changes in those pricing periods that might be expected as you add and transition entirely over the next 28 years.

Q. Is it your understanding -- thank you.

Is it your understanding that partially in response to those concerns and concerns raised by CCEBA and some other intervenors that Duke Energy changed their assumptions about the dispatch of solar in storage in modeling SP5 and SP6?

A. Yes. In SP5 and SP6 they were modeled as two separate resources, and so the EnCompass algorithm was able to dispatch storage according to the system needs in real time. And I believe that is one of the contributing factors as to why the model shifted from standalone solar to solar plus storage.

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Q. I was gonna ask you, did the Duke model tend to favor the inclusion of more solar plus storage resources once those changes were made compared to P1 through P4?

A. Generally, yes. In think -- in fact, I believe SP5 and SP6, the CAPEX models, which only provide preliminary results, which are then adjusted through a few out of model steps, almost entirely selected -- only solar plus storage, very little standalone storage selected.

Q. Putting aside --

A. Standalone solar. Sorry.

Q. Thank you. Putting aside the issue of recommended near-term actions, do you agree that, if solar plus storage is modeled with more flexibility in its dispatch, EnCompass and other models tend to select it as an economic resource?

A. Yes.

Q. Do you agree that modeling solar plus storage to charge bidirectionally from the solar component or from the grid tends to make solar plus storage a more economic resource in EnCompass and other models?

A. That's hard to say. And I certainly didn't reach that conclusion necessarily in my testimony. As

I explained in my testimony, EnCompass doesn't currently allow that, it's either one or the other. You're either AC connected only from the grid, or DC connected only from the resource.

I think there's value in having that bidirectional storage, and potentially could reduce some of the standalone storage which is being utilized for grid charging that's being deployed because the solar plus storage cannot charge from the grid. I hope that this is an improvement that EnCompass implements in the future, because I think it would provide a little more granularity there, and potentially -- potentially, you know, reveal additional benefits.

But, obviously, that has to be weighed against incremental costs, bidirectional inverters, operational control that might be put on that storage by the Duke system operation team and other factors.

Q. Would you agree that the technology does exist -- let me strike that question.

Would you agree with witness Ron DeFelice from CCEBA that that technology is currently in the market to allow bidirectional charging?

A. I have no reason to not believe that.

Q. Okay. Would you agree that it's necessary to

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1 develop commercial terms to allow Duke Energy control
2 of the solar and battery resources procured as part of
3 the Carbon Plan?
4 A. Yes. I think we spoke about that with solar
5 plus storage and would like to see those terms develop
6 before the 2023 procurement, which we expect would take
7 additional solar plus storage.
8 Q. Mr. Metz?
9 A. (Dustin Metz) I mean, if I understood your
10 question correctly, you said Duke have control. I
11 think there might be a nuance in the question there. I
12 just think the commercial terms need to be created in
13 such a way so dispatch can occur. I don't know if the
14 context of Duke control is necessarily the caveat
15 there, that it could be a commitment schedule or could
16 be that Duke sends out a dispatch signal and y'all
17 follow that signal. Just getting hung up on the Duke
18 control.
19 Q. Understood. I thank you for that
20 clarification and I accept it.
21 Would you agree that it's important for the
22 commercial terms that we develop, or that are developed
23 in anticipation of the 2023 procurement, to fairly
24 compensate operators or owners for the resources they

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make available?

A. Yes.

Q. And to protect ratepayers as well?

A. Yes.

Q. Thank you. I'm gonna turn to another topic now. At various points in your testimony, Mr. Thomas, you discuss the concept of execution risk.

Can you tell me what you mean by that term and how the Public Staff has used it in evaluating proposed portfolios in this case?

A. (Jeff Thomas) Sure. And witness Metz may have more on the transmission side, but I think, broadly, execution risk is just the failure to achieve modeled results in the real world due to a variety of factors of risk factors. So you might be looking at is the pace of the build-out sustainable; can we interconnect this much; can we acquire this much land; can we import this much natural gas.

You know, there's factors, real-world factors that are not modeled in the EnCompass model, and those factors can lead to confounding the ability to get to those, kind of, least-cost optimal results. And so those have to be taken into consideration. You know, if you told me that a portfolio needed to add 10,000

megawatts of solar every year, and that's a big execution risk, and those factors are not always reflected in the modeling, so that's what we were trying to assess there.

Q. Okay. Am I correct or do I understand correctly that in evaluating execution risk, you're -- I think I understood, you're attempting to evaluate the chances that a given resource in a portfolio will perform in the real world the way it does in the model?

A. I think the performance, not necessarily, I think it's just the ability to build -- to build a resource, that commercial availability of a technology, when it could become available, when, you know, is the commercial operation date and the timeline for construction envisioned in the Carbon Plan, is that realistic. I think those are really the challenges there.

Once the unit is in service, and to the extent that operations might deviate from the optimal model, I think that's just a fact of life, that the model has perfect foresight and the system operators do not. But really execution is getting to that commercial operation date and achieving those carbon reduction targets.



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Q. Mr. Metz, do you have anything to add to that?

A. (Dustin Metz) It was just in complement to that is the reliability of the system, ensuring the operators maintain reliability.

Q. Am I correct that if you determine that a proposed portfolio relies on or assumes resources that your research or knowledge leads you to conclude is less than likely to be available when scheduled, then that portfolio can be said to have more execution risk than another portfolio that does not include those assumptions?

A. (Jeff Thomas) I'm sorry, could you rephrase that?

Q. Sure. I'm grasping questions about concepts that I understand through a glass darkly. So be careful.

Am I correct that, if you determine that a proposed portfolio relies on or assumes resources that your research leads you to believe is less likely to be available when scheduled, that portfolio can be said to have more execution risk than a proposed portfolio that does not have those assumptions or resources built into it?

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A. Yeah, to a certain extent. But the addition of new resources is not the only factor.

Q. Okay.

A. We have to consider both the timelines for transmission system build-out, the timelines for interconnection of resources that are commercially available at this time. But yes, generally, yes. If Duke modeled a fusion reactor in 2035, I think we would be skeptical of that date, but I think in general --

Q. Did you read my notes, because that was one of my next questions? Thank you.

A. In general, we found that the assumptions that Duke used, particularly SMRs, reflect, to a certain extent, reasonable assumptions about the -- because I could tell you're going towards SMRs -- the reasonable assumptions about the commercial availability of that technology based upon information known today.

Will that maybe be wrong? Yes. But we'll revisit this in 2024. We may have more information on status of the industry by then. The NRC may take some actions, we may see -- if we see further delays, then in 2024 we may need to adjust that first availability date. If we see more progress than expected, we may

pull it in. But that's the iterative nature of this update process.

A. (Dustin Metz) And another point of reference is, if you're trying to evaluate the execution risk of a 300-megawatt unit with a potential production profile versus a 1,600-megawatt unit with the same production profile, there's a lot more risk if that 1,600-megawatt facility didn't come online and the ability to recover compared to the 300-megawatt profile if you put all the production profile capacity factors and contribution system needs on the same level playing field.

Q. On page -- in your testimony on page 13 and 14, Mr. Thomas, I'll start on page 13 at line 7.

A. (Jeff Thomas) I'm there.

Q. Okay. You state that the Public Staff's initial comments detailed specific concerns regarding the execution risk and costs associated with Duke's Portfolios 1 through 4, and compared the Carbon abatement cost of meeting the interim goal by 2030 relative to the social cost of carbon.

In summary, the Public Staff has serious concerns about Duke's ability to interconnect the amount of renewable generation that must be installed by 2030 to meet the targets, particularly given the

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1 challenges associated with the required major
2 transmission network upgrades which will almost
3 certainly involve more than only the 18 projects.
4 Is that your testimony?
5 A. Yes.
6 Q. You then move on on line 20 and state, "In
7 addition, the Public Staff is concerned that P1 is the
8 most vulnerable to cost overruns related to delayed
9 schedules and material price increases, as it relies
10 heavily on aggressive additions of solar and storage,
11 both of which are experiencing substantial near-term
12 cost increases related to global inflation and supply
13 chain issues."
14 Is that your testimony?
15 A. Yes.
16 Q. I want to draw your attention to that
17 sentence that begins with "in addition, the Public
18 Staff is concerned about price increases."
19 That's a step further than the Public Staff
20 went in its original comments, isn't it, in terms of
21 what the execution risk is about P1?
22 A. No. I'd have to look back at my comments,
23 but I believe we did specifically discuss the potential
24 for cost overruns. When you procure huge volumes of a

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1 particular -- of one particular resource that is
2 experiencing a lot of uncertainty in the market, and
3 we've been hearing from solar developers that the
4 countervailing duty -- duties and investigation could
5 have major impacts. And when you put all your eggs in
6 one basket, as it were, we felt that you're more
7 vulnerable to -- you know, a cost overrun of 20 percent
8 is more impactful when you're installing, you know,
9 1,200 incremental megawatts versus not installing that.
10 So I think we were really focused on that
11 enormous initial built-out as being potentially more
12 risky in P1, because there is significantly more solar
13 added in that portfolio.
14 Q. So it's your testimony that P1 has the
15 highest risk of cost overruns due to its reliance on
16 solar and solar plus storage?
17 A. It's got -- P1 has the highest exposure to
18 cost overruns related to solar cost overruns relative
19 to other portfolios by that date.
20 Q. Are you familiar with the price curve for
21 solar PV technology over, say, the last 15 years,
22 Mr. Thomas?
23 A. I am.
24 Q. Would you agree that the cost of solar PV

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systems has declined since solar first became part of the North Carolina grid?

A. Yes.

Q. And it's fair to say there's been some instability in that pricing as a result of some of the factors you mention in your testimony recently, tariffs and other supply chain issues; is that right?

A. Yes. And, you know, the cost curve, you know, has -- it's been disrupted, and I think a lot of the capital costs estimates, you know, that we've seen don't always reflect that disruption. And it's uncertain when that will resolve. We don't have certainty to see through this to see when those -- that cost decline will resume, if it will.

Q. Would you agree that the IRA may, in fact, have significant effect on that supply chain?

A. It certainly could, although I'll caveat that with the ITC and the IRA is heavily dependent upon developers. There's a very low base ITC, but there's bonuses associated with domestic content manufacturing guidelines, prevailing wage standards, siting guidelines.

And there's no guarantee that developers will be able to capture all that bonus. But if they could,

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yes, it could result in additional price declines.

Q. Would you agree that the market for solar PV systems is a mature market with an established supply chain in the United States?

A. I can't speak to the supply chain in the United States.

Q. Let me rephrase that question, because I left that ambiguous by accident.

Would you agree that the market in the United States for solar PV systems is a mature market and has an established supply chain?

A. Yes, I believe so.

Q. Thank you. But your concern today that supply and demand issues with solar and storage will reverse the historical trend?

A. I think that the near-term trend is important to consider here. I think over the next 10 years, will we continue to see price declines in solar? Probably, but I can't see the future. You know, significant amount of panels come out of the southeast Asian region and China, and there's no -- there's a lot of uncertainty geopolitically now.

So it's hard to understand really what might happen in the future, but it's safe to say that in the

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near term, prices have gone up, and they could go further. And very, very high levels of procurement in the near term could capture that price increase to a certain extent that may not be beneficial to ratepayers.

Q. As a matter of just basic econ 101, when demand outstrips supply, price rises, right? Generally speaking?

A. Generally. Although that's -- that breaks down when you have tariffs and taxes and --

Q. Certainly. The Public Staff is not recommending the approval and adoption of any of the specific portfolios in this proceeding beyond the near-term execution plan, are you?

A. I believe we recommended that the Commission take into account the modeling changes in SP5 when it adopts its Carbon Plan, because we believe that was more appropriate. But as far as specific resource selection, we don't feel it's necessary to select a portfolio that locks us into resources throughout time, that's why we've recommended Near-Term Action Plan.

Q. In the Near-Term Action Plan recommended by the Public Staff, you make recommendations for the quantities of solar that you recommend be pursued in

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'22, '23, and '24, correct?

A. Can you point me to my testimony?

Q. Take a look at page 63 of your testimony. And I believe you amended some of this testimony this morning. Let me know when you get there and I'll get there with you. Hold on.

On the chart on page 63, is it a fair characterization to say that you recommend SP5-compliant solar and solar plus storage in the amount of 4,250 megawatts as part of the Near-Term Execution Plan?

A. So that table in the Near-Term Action Plan essentially summarizes the resources that were put in service by the end of 2029, so that would be full year of 2030. And we attempt to take that quantity and try to back that out to a procurement target for the 2022 solar procurement. But I don't recommend targets outside of that. A lot depends on the pricing that we receive, market trends, and the development of future solar procurement RFPs.

Q. Is it your testimony that those procurements don't carry the execution risk that you state confronts Portfolio 1 before 2030?

A. No, they absolutely do. A target that we

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recommend of 1,200 megawatts in the 2022 solar procurement absolutely does carry execution risk. We may not procure that much, it may be more expensive than if we waited a year, maybe less expensive. We may see defaulting PPAs as interconnection targets aren't reached. We may see developers back out after signing a PPA because prices went up.

There's a significant amount of execution risk. We're not suggesting that any pathway has zero risk, but we think we're trying to balance costs, risk and CO2 reductions along with system reliability in some of the targets that we've recommended.

Q. It's possible, though, to ameliorate some of the interconnection concerns and transmission concerns that you stated create the execution risk for a solar-focused portfolio, isn't it?

A. Yes. And witness Metz addresses some of these amelioration efforts in his testimony.

Q. And it's actually -- what was I was gonna look at is your testimony on page 69. And, Mr. Metz, if you have something to add, I'm happy to hear your response as well.

But to save the time of reading from line 12 of 69 to line 2 of 70, in that paragraph, you discuss

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that large quantity and geographic diversity of projects that have bid into at least the 2022 procurement, you believe it's likely that some of these targets and the spreading out of these projects interconnection over time might ameliorate that risk, right? Is that a fair characterization of that -- it's certainly not a quote, but --

A. Yeah. I think what I'm trying to get at here is that, you know, we recommended -- we found that Duke's interconnection limits were generally reasonable for resource planning. But then we go and recommend a higher 2022 procurement target than Duke used in its baseline. And what I'm just trying to say here is that, you know, we're not exactly tying the procurement to the quantities selected in a given year because the 1,200 megawatts, or however many megawatts are procured in the 2022 procurement, might come in over a range of time periods.

I expect some to come in in 2025, some to come in in 2026, and some even in 2027, particularly if they're dependent upon the red zone upgrades, which many of which are not expected to be completed until 2026.

Q. And some of the procurements in later years

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would also likely be spread out in terms of when they would interconnect; isn't that right?

A. I think potentially there's always gonna be a range of projects that bid in, some with completed facility studies and interconnection agreements will be able to connect sooner. Some that are in near -- early term development that have barely even got site control, those will take much longer to get interconnected.

Q. And Mr. Metz?

A. (Dustin Metz) For context of risk, and we were sort of having a conversation of putting all your eggs in one basket, this is how we evaluate this, the transmission upgrades, regardless in the red zone or not, are gonna take time. Larger the project, one can assume it's just a larger scale of scope and it's gonna take time.

I'm not aware that anyone in this room can control Mother Nature and what foresight that we can have in this schedule, and I mean that respectfully. So when we look at the schedule of these implementations that we've reviewed, Duke has, in my words, aggressively removed some of the project management fluff or cushion to potentially address some

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of these Mother Nature items that do occur in the Carolinas.

So I'm just -- adding caution is -- when we evaluate sort of the risks, it's also taking into consideration some of these other elements that can't be captured in the model in a more real-world planning scenarios that we have to rebound from.

A. (Jeff Thomas) If I can add one more thing too. The solar interconnection limits and the challenges associated with those, that's not in a vacuum, right? We also, in our Near-Term Action Plan, recommend the procurement of 600 megawatts of onshore wind, and some of that may be PPAs and not require -- you know, but those will still require point-to-point transmission. You know, securing that.

Recommend 1,100 megawatts of battery storage standalone, that's gonna need studies, as we heard yesterday. There's gas CTs and CCs. Those need to be studied and interconnected, and they all have their requisite transmission impact.

So looking at it just in terms of how much solar can we interconnect is a bit myopic. And we need to look at the whole resource portfolio that we're trying to interconnect and realize that this is a

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1 challenge for Duke's transmission interconnection
2 studies and Dukes transmission planners that I don't
3 believe that they've ever faced before, in terms of
4 interconnecting this volume of intermittent resources
5 and dispatchable resource and energy storage
6 simultaneously. So I think we need to temper this with
7 some dose of reality.
8 Q. Understood. And I don't disagree with you
9 there, but I want you to take a quick look, for ease of
10 reference, at Figure 6 of the Carbon Plan, which is
11 page 14 of the executive summary.
12 Do you have that in front of you?
13 A. I actually don't have the executive summary
14 in front of me. Is it in Appendix A?
15 A. (Dustin Metz) Page 6?
16 Q. Page 6 of the executive summary. I think
17 it's 6 of the entire plan, I believe. It's Figure 6,
18 I'm sorry, page 14.
19 A. (Jeff Thomas) Okay. Yeah, I'm familiar with
20 this graphic.
21 Q. Just -- this is a representation -- Figure 6
22 is a representation by Duke of sort of a timeline of
23 when certain -- what resources are on in a given
24 portfolio at the time that the portfolio achieved

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70 percent reduction; is that right?

A. Yes.

Q. And only -- by looking at the whole Carbon Plan and at this Figure 6, only Portfolio 1 would meet the 70 percent CO2 reduction required by HB 951 by 2030, correct?

A. Yes. Only P1 achieves it by 2030.

Q. And P2 through P4 are projected to meet that deadline later and in reliance on concentration of other technologies?

A. They are projected to meet it later, yes.

Q. And using concentrations of other technologies, other than solar, at the level in Portfolio 1?

A. Yeah. I mean, if you look at the interim compliance date, yes, they're different. But looking at 2035, many of those -- even P1 adds many of those same resources.

Q. Right. But it doesn't do so -- it doesn't rely on those additional resources to meet the 2030 70 percent decline, does it?

A. No, it does not rely on, say, pump storage or new nuclear.

Q. It stands to reason, doesn't it, that Duke

wouldn't propose a portfolio that they did not think they had the capability of executing?

A. I think P1, in particular, Duke has been very clear in its filing that it did not believe that the interconnection rates used in that study for solar were reasonable. We found that they presented more risk. And so I can't speak to whether or not Duke thinks all of these are equally achievable. I think P1 has the most challenges and could -- would be more costly to ratepayers over time.

Q. Okay. The other portfolios proposed by Duke do not project themselves to achieve the reduction of 70 percent by 2030. I think we've covered that.

P3 and P4 both, to some extent, rely on SMRs or new nuclear, correct?

A. That is correct.

Q. Correct me if I'm wrong, but they are actually dependent upon 300 megawatts of SMR coming online before 2034 along with 1.7 megawatts of new pump storage; is that right?

A. While those two portfolios are dependent upon that to reach the interim compliance, all portfolios are dependent upon that to move beyond the 2030 compliance. And 951 doesn't cut off at 2030.

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Q. Understood.

A. We have to plan for 2030.

Q. But my question is whether they're reliant on those technologies to achieve, by Duke's statement, the 2030 70 percent reduction?

A. No, those -- P1 and P2 are not relying on new nuclear pump storage. They are relying upon new gas resources, significant quantities of onshore wind, batteries, and solar.

Q. Okay. You and the Public Staff describe Duke's assumptions on new nuclear as reasonable; is that right? On page 48 of your testimony, if you don't mind looking at that.

A. (Witness peruses document.)

Page 40?

Q. 48.

A. (Witness peruses document.)

Q. The question is, does the Public Staff find Duke's assumptions regarding non-commercialized technologies to be reasonable. And in your response on line 8 -- wait. Actually, that one says -- let me make sure I'm on the right page. 48. You state, "Duke's assumption," beginning on line 7, "that new nuclear resources will be available in the future is not

unreasonable," right?

A. That's what I say.

Q. But you do go on to say it is impossible to know for certain at this time when new nuclear will first become available or at what price, right?

A. Yes. I think that's out of our hands. A lot of that relies upon the NRC and the individual manufacturers. So no one knows for certain when that is, but we found the dates used by Duke to be reasonable for planning purposes. I think it's undeniable looking at all the portfolios, SP5 and SP6 included, that new nuclear is going to be an important component of meeting not only potentially 20- -- the interim compliance, but the 2050 net neutrality, or the carbon neutrality.

And the selection of these resources across all portfolios, including in some other intervenors' portfolios which selected new nuclear resources, we believe that the dates in the Carbon Plan may be ambitious. But it still is worthy of exploring those options in the near-term.

Q. With regard to Duke's requested near-term execution actions related to SMR licensing and siting, Mr. Metz, on page 26 of your testimony, you do not

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dispute those amounts, do you?

A. (Dustin Metz) So starting on page 26?

Q. Of your testimony; yes, sir.

A. (Witness peruses document.)

Q. Are you disputing the cost and required activities that Duke has stated; no. Correct, at the bottom of the page?

A. Correct. And also I do not have the means to measure, evaluate on Duke's listed activities.

Q. So you have no transparency into what those expenditures are or what those actions are, but you don't find them unreasonable?

A. I don't find it unreasonable that work will need to take place to set us up to potentially evaluate and refine cost estimates for new -- either new nuclear or the Bad Creek II project.

Q. Would you agree, though, that it would be prudent for the Commission to require Duke to carefully and transparently report those expenditures to the Commission during the three years covered by those projections?

A. Yes. I believe Public Staff witness Boswell covered some of this topic in her testimony as well.

Q. Okay. Would you agree it would be prudent to

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impose a cap on such expenditures that Duke cannot exceed without permission from the Commission and explaining why they need to exceed it?

A. I'm going to defer to Public Staff witness Boswell on that.

Q. Thank you. On page 20 of your testimony, Mr. Metz, beginning on line 16, you state -- are you there? I don't want to rush you through.

A. Page 20, line 16?

Q. Yes, sir. You state, "The three long lead-time resources have the potential to take a decade or more to develop from concept phase to commercial operation. Some, particularly SMR deployment and future BOEM offshore wind leases, are also dependent on factors largely outside of Duke's control," correct?

A. That is correct.

Q. What factors in SMR deployment are largely outside of Duke's control?

A. So focusing in on SMR deployment. So for modeling purposes, we evaluated -- Duke evaluated multiple different SMR technologies -- or correction, it was a couple of SMR technologies, and they had their respective costs. I cross-referenced those potential costs back to the AEO 2021 and 2022, and found those

costs to be within reason within those proxies that were published data.

The deployment -- or correction, the licensing by NRC for each one of those reactor technologies are one of the many factors that are really outside of Duke's control. For example, NuScale did have their earlier variant -- I might be off on the megawatts here -- their 50-megawatt variant actually approved by NRC. But it was my understanding, while NuScale was doing the licensing of the 50-megawatt project, they found that they can get increased megawatt output. They had headroom in their design to go to the 77-megawatt design, subject to check on the 77-megawatt design.

Since that increased the megawatts, that new megawatt design would also have to go through NRC, which is currently underway. But one of the other technologies that are listed -- I'm gonna -- I'm pausing here for a second because some of the information is in the supply side data manual.

Q. You don't -- I think maybe you're going into a little more detail on the particular units than I necessarily wanted in the question. So if you're about to venture into confidential information, please don't.

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Understanding that it's there.

But there are issues that are outside of Duke's control about SMR technologies, such as the location, supply, the fuel, events in the Ukraine, issues that we discussed with Duke's panel over the last few days, correct?

A. That's correct. But that's one of the reasons for the near-term activities, which does not get to that level of implementation of the technology.

Q. Gotcha. Mr. Thomas, going back to page 48 of your testimony where you discuss SMRs.

A. (Jeff Thomas) Yeah.

Q. You state -- and we already -- you already said -- agreed that this was your testimony, that it's impossible to know for certain at this time when it will first become available or at what price, but then go on.

And is it fair to say that, in that portion of your testimony, Mr. Thomas, you're discussing the reasons why it is reasonable for Duke to assume that SMRs will become available to be used in their portfolios on the schedule they propose?

A. I think what I'm trying to describe here on this page of my testimony is that it's reasonable to

include SMR as a selectable resource in the Carbon Plan model. I think that's reasonable because, from when I sit, from my perspective, I think it's highly likely that SMRs will be approved by the NRC and that this capacity will start to be deployed in some level on the U.S. grid.

I think the challenge is what is that first year; when do we allow the model to select that technology. And I think that, you know, there's a lot of discussion about what is the appropriate date; is 2032 too early, is it too late. But ultimately that's an assumption that we have to make based on our imperfect knowledge today. And I think it's a reasonable assumption at this time that we will revisit in future plans.

But not performing some of the predevelopment activities could potentially sabotage some of those efforts to be prepared to at least execute on the actions that Duke can execute on to safely and reliably deploy the SMRs that are selected in the model to provide those carbon reductions and maintain system reliability.

Q. Looking at page 49 at the top of the page, you state, "Utilities across the country are planning

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to incorporate SMRs in their future generation portfolios with 19 utilities planning to add a combined 90 gigawatts of SMRs to the nation's grid by 2050"; is that right?

A. Yes. And there are particular -- I have not reviewed every IRP across the country, but I was able to find several utility IRPs that do include SMRs as a selectable resource and some that do -- some of those do select those SMRs as the most economical way to achieve decarbonation targets.

Q. So all those things lead you to the conclusion that a market for SMRs will exist and will develop further within the time frame of the Carbon Plan; is that right?

A. By 2050, yes.

Q. Did you hear the testimony of the Long Lead-Time Resources Panel two days ago?

A. I was listening, yes.

Q. Did you hear them agree with me that there is no SMR unit online and producing commercial power anywhere in the world as of today?

A. Yes.

Q. You will agree, then, that it's impossible for there to be an SMR supply chain in place currently,

correct?

A. (Dustin Metz) I would characterize it that the supply chain that -- there are current R&D activities underway to support the development of SMR research.

Q. But there's not a supply chain for the parts needed to construct the SMR or the building that SMR is housed in, is there?

A. I would generally agree that there is not a supply chain to mass produce 90 gigawatts of SMRs today.

Q. And an SMR online by 2032 would, by definition, based on the timelines that Duke discussed in its Carbon Plan in testimony this week, be one of the first commercial SMR plants brought online in the United States, wouldn't it?

A. No, I wouldn't agree with that, because it's my understanding the facility -- I want to look over to my left -- the facility out West, I believe, was 2027 or 2028, subject to check. And I believe there is development in Canada on approximately 2030, I can't remember the exact date.

Q. And those aren't the same technology, those are two different designs, right?

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A. I can't remember the designs off the top of my head.

A. (Jeff Thomas) I want to just reiterate to that. You know, while Duke did select one particular SMR unit to model here, you know, for operational characteristics, there are many models, there are many types that are being developed. You know, there's the GE, there's NuScale, there's other brands.

And I think a lot depends on -- you know, I don't want to get too hung up on the particular manufacturer and just looking as a technology, selectable technology, and, you know, the GE could abandon their plans, but NuScale could move faster than expected, and that would obviously change the type of model that we represent in future Carbon Plans.

And I don't believe that any of Duke's near-term actions related to nuclear specifically focus on procuring or ordering parts or placing orders with GE, but rather are doing the preparation necessary to facilitate whatever SMR comes into commercial operation.

Q. I understand that. I don't disagree with your point there, and we're talking about the market for the technology and the actual equipment itself is

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what I'm asking about.

And would you agree with me that there is not likely to be a tested shock-resistant and resilient supply chain for this new technology by 2030 or even 2032?

A. (Dustin Metz) That doesn't mean that one can't be built and online and approved by the NRC.

Q. But the demand for the units, assuming all of our hopes about them come true, will certainly ramp up rapidly after that point, right?

A. That requires too much speculation. What do you mean by ramp?

Q. Okay. Will increase rapidly after that point if we're gonna build the 90 gigawatts anticipated in your testimony.

A. (Jeff Thomas) Yeah, I think if that's the actual demand, then that would require ramping up. But for small modular reactors, that's kind of the point. The more that you build, theoretically the cheaper that they get. And I'd just also point out, we're talking about what might happen in 10 years. Ten years ago there was no market or supply chain in North Carolina for installing megawatts of utility scale solar, right? There was very little. Maybe 10 years ago very, very

savvy people could have predicted that we'd have this much solar in the state, but you know.

So I just want to emphasize that things change over time, and we're gonna be revisiting these assumptions in the future. And if these assumptions about in-service dates become more questionable in the future, we'll adjust that, but we have to make some adjustments today.

Q. But if I understand your testimony, it's reasonable for Duke to assume that a brand new technology with a brand new and untested supply chain will meet unprecedented worldwide demand and still present less of a risk of cost overruns than solar and solar plus storage?

A. The SP5 model that we catered our Near-Term Action Plan to has significant quantities of solar, solar plus storage, and standalone solar, so I don't understand. We're not putting all of our eggs in the SMR basket here. By 2030, I think there's 300 megawatts of solar or of SMR capacity. If that doesn't happen, if that doesn't materialize, that's 300 megawatts on a 30-, 40,000-megawatt system. You know, solar is much larger in contribution in terms of the amount of capacity that must be installed.

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So I think we need to put this SMR thing in context, right? It's obviously relied upon much by 2050, but I think that by 2050 those assumptions will change dramatically, potentially significantly.

But for interim compliance by 2035, we're not talking about gigawatts of nuclear. This is very small relative to the total capacity being added. So I just don't want to get caught up so much on what's better, one SMR unit or, you know, five times the capacity of solar plus storage, which might be required to actually replace that small amount of nuclear capacity, and focus more on what's reasonable for planning purposes today.

Q. The long-term modeling and assumption of SMRs and other long lead-time technologies in the out years of a Carbon Plan will affect what goes into the Carbon Plan in the early years, won't it?

A. (Dustin Metz) Are you talking about the inputs? Can you clarify that?

Q. Strike that question. It's way too complicated do on the fly, so I'll drop that question. It might lead to a long colloquy that we don't have time for.

During your time in the Public Staff,

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Mr. Thomas, has a new nuclear resource ever been brought online on time and under budget in North Carolina?

A. (Jeff Thomas) No.

A. (Dustin Metz) There's been no project -- new nuclear built in North Carolina since my time on the Public Staff.

Q. And you heard the discussion yesterday about the Lee plant with the Long Lead-Time Resource Panel?

A. I'm generally familiar with the Lee nuclear plant in South Carolina.

Q. And in 2017, Duke Energy sought approval for a 13.9 percent rate increase and sought to recover $368 million in planning and development costs when canceling the Lee plant?

A. Yes.

Q. That plant was scheduled to cost $6 billion when announced in 2005, right?

A. Subject to check.

Q. And by 2008, it had grown to $11 billion?

A. Subject to check.

Q. And this was similar to the chronic cost increases that have affected the Vogtle plant in Georgia, are you familiar with that plant?

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A. Yes, I am familiar.

Q. And that was similar to the chronic cost increases to those that ultimately killed the V.C. Summer plant in South Carolina, right?

A. I'm generally cognizant of the V.C. Summer plant challenges.

Q. Okay. Thank you. No further questions.

CHAIR MITCHELL: All right. CIGFUR?

MS. CRESS: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MS. CRESS:

Q. Good afternoon, gentlemen. As you know, my name is Christina Cress, and I'm here on behalf of CIGFUR. Mr. Thomas, I'll start with you.

You testified that the Public Staff finds an interim compliance date of 2032 to be generally reasonable; is that correct?

A. (Jeff Thomas) Can you point me to my testimony there?

Q. Sure. I believe it is on page 6 of your testimony, line 13.

A. (Witness peruses document.)

Actually, that, I'm discussing Duke's near-term procurement activities associated with an interim compliance date of 2032, and find them or the

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near-term procurement activities generally reasonable. Later in my testimony, I recommend that Duke be required to meet the interim goal by no later than 2032.

Q. So then is it fair to characterize your assessment of Duke's interim compliance date of 2032 to be reasonable?

A. I don't believe -- I mean, Duke modeled different dates for interim compliance, 2030, 2032, and 2034, and we've reviewed the costs and the potential benefits of each of those and execution risks. We found that we don't believe that Duke has justified a delay beyond 2032, pursuant to the language in 951. So we think that achieving a compliance goal by 2030 or 2032 would be reasonable.

But looking at the execution risks and the incremental costs to North Carolina ratepayers of 2030 compliance relative to 2032 compliance, we have serious concerns about those incremental costs and whether or not they justify the Commission's discretion in the optimal timing and generation mix.

Q. Thank you for that. And SP5 would have an interim compliance date of 2032; is that right?

A. That's correct, that's how we modeled it.

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Q. And SP6 would have an interim compliance date of 2034?

A. That's correct.

Q. Okay. At this time, I would like to introduce for the sake of time two exhibits, if it's okay. They'll pertain to the same line of questioning. And I'll represent for the record that these are Figure 1 and Table 3, which were taken from the Public Staff's comments filed in this docket on July 15, 2022.

A. I'm sorry, what table is that?

Q. Table 3 and Figure 1.

A. Okay.

MS. CRESS: Chair Mitchell, I request that Table 3 be marked as CIGFUR II and III Public Staff Thomas, Metz, and Williamson Panel Direct Cross Examination Exhibit 1.

CHAIR MITCHELL: All right. Motion is allowed.

MS. CRESS: And that --

CHAIR MITCHELL: Actually, I'm sorry. The document will be marked for identification as CIGFUR II and III Public Staff Thomas, Metz, and Williamson Panel Direct Cross Examination Exhibit Number 1. And I'll go ahead and allow the second

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1 document to be marked CIGFUR II and III Public
2 Staff Thomas, Metz, and Williamson Panel Direct
3 Cross Examination Exhibit 2.
4 MS. CRESS: Thank you, Chair Mitchell.
5 (CIGFUR II and III Public Staff Thomas,
6 Metz, and Williamson Panel Direct Cross
7 Examination Exhibits 1 and 2 were marked
8 for identification.)
9 Q. Mr. Thomas, you were just testifying a moment
10 ago about the costs of expedited -- a more expedited
11 compliance.
12 Can you walk us through Table 3 and what it
13 shows here and your conclusions, if any, that you
14 reached from looking at this table?
15 A. Sure. So as one part of our analysis, we
16 wanted to look at, you know, what is the benefit to
17 ratepayers, what is the incremental cost of 2030
18 compliance relative to the later compliance, and try to
19 put that in context.
20 So what we did is we looked at the
21 incremental CO2 for P2, 3, and 4 relative to P1, and
22 you can see that in the second column of Table -- or
23 the third column of Table 3. And then we looked at the
24 PVR savings relative to P1. So, for example, P2, I

1 believe through 2035 emits 23 million tons -- short
2 tons more than P1, but costs $1.7 billion less in PVR
3 terms.
4 So when you divide those numbers, you come up
5 with the cost of carbon abatement and the $1-per-ton of
6 $76. And that's P1 relative to P2. So essentially, to
7 achieve that 2030 compliance instead of 2032
8 compliance, you are paying $76 per short ton of carbon
9 emissions, for removing that emissions.
10 And then when I compare that to the social
11 cost of carbon published by the White House Technical
12 Panel, you know, one reason I reference this was, you
13 know, EO 246 from the governor does reference this
14 figure as something to consider in decision-making. We
15 don't find it to be determinative, but we thought it
16 was illustrative. Based on the weighted costs, the
17 calculation for that, the footnote has some more
18 details about the 3 percent discount rate and an
19 emission year of 2035, that cost is 61.
20 So that represents the cost of each -- the
21 social cost, we're talking about, you know, health
22 benefits, carbon, climate change as estimated by this
23 panel, to be $61. So this is saying essentially that,
24 for every ton of carbon removed, North Carolina



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1 residents are paying $76 to achieve compliance in 2030,
2 but the benefits associated with that removal of carbon
3 are only $61 per ton.
4 And for us, that kind of indicated that this
5 earlier compliance is -- the Commission has given
6 flexibility, we're trying to balance cost, execution
7 risk, reliability. And we were concerned that the cost
8 exceeded the benefits in this simple calculation.
9 So again, we don't find this to be
10 determinative, it's not the only factor we looked at
11 when discussing the interim compliance date, but it is
12 one of them.
13 Q. Thank you for that. And I saw you nodding,
14 Mr. Metz. Is there anything you would like to add?
15 A. (Dustin Metz) No, I was agreeing.
16 Q. Excellent. And, Mr. Thomas, I'll now turn
17 your attention to Exhibit 2.
18 Is it fair to say that this chart represents
19 the fact that Duke's four portfolios, as proposed,
20 follow a similar trajectory to carbon neutrality in
21 2050?
22 A. (Jeff Thomas) Yes. The only difference
23 really is the interim compliance date and how that's
24 achieved.

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Q. Thank you. Mr. Thomas, what is your opinion about whether the inclusion of a generation resource in the Commission's Carbon Plan should be controlling in a CPCN proceeding?

A. I believe, generally, we -- any generation resource that Duke comes in for to build should require a CPCN. And the normal process of review for necessity and need should be followed in that CPCN. And the selection of that resource in the Carbon Plan is certainly one factor we would consider in that, but we also need to look at updated modeling, right? If Duke comes in for a combined cycle and gas prices have tripled and are expected to maintain that elevated status, then that would be something we would consider in reviewing our position on that CPCN.

Q. And since you mentioned Duke potentially coming in for a future CPCN for a new natural gas plant, would a hypothetical future CPCN proceeding for a new CT or CC evaluate the reasonableness of any proposed new natural gas plants?

A. I think that's generally the approach we take in CPCN proceedings, is evaluate the reasonableness of the proposed plant.

Q. And will that proceeding include an analysis

of more recent and up-to-date recent gas price forecasts and market conditions?

A. I would expect so. I think we would expect that type of analysis from Duke. And, potentially, we'd investigate that, in terms of updated commodity prices and other factors.

Q. Thank you. Moving on.

The supplemental model portfolios in SP5 and SP6 did not select offshore wind in the next 10 years; is that correct?

A. That's correct. I believe they were in about 2040, 2041 there was capacity selected.

Q. Is that because offshore wind is not a least-cost resource right now?

A. I'm not sure. You know, when the model is selecting or not selecting offshore wind, it's evaluating against a suite of alternatives. And it is not least cost prior to 2040, perhaps, but at that time the model is determining that it could be. Obviously, a lot depends on the updates. But, you know, I wouldn't say necessarily that offshore wind is not part of a least-cost solution.

Q. Thank you. Turning now, Mr. Williamson, I'll ask you a couple of questions.

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You testify on page 19 that the only way the Companies can meet the 1 percent DSM/EE target is if Duke's proposed regulatory changes are approved by the Commission for planning purposes; is that correct?

A. (David Williamson) You said page 19?

Q. Yes, sir.

A. (Witness peruses document.)

I'm sorry, can you point me where on page 19?

Q. Sure. Give me one second. Hopefully I have not --

A. Oh, I see it.

Q. -- gotten the -- okay.

A. I see it. So sorry for the delay. What was your question again?

Q. You testified that the only way that the Companies can meet the 1 percent DSM/EE target is if Duke's proposed regulatory changes are approved by the Commission for planning purposes; is that right?

A. That's right. And I kind of get into it a little bit on the previous page. Essentially, the Company made a very broad statement about how they came to this 1 percent, and at the very tail end of it, as far as how they considered the achievability of this 1 percent, they included the potential impacts of some

identified enablers. So that's where I made that conclusion.

Q. Is the Public Staff recommending that the Commission approve Duke's proposed regulatory changes with respect to DSM/EE?

A. Inside of the Carbon Plan, no. In fact, we mention -- I mention in my testimony a number of times that these types of changes and these types of requests are more appropriate within a mechanism review where we can take into account a number of different factors as well as potentially within just the regular DSM/EE rider proceedings, depending on the enabler that they would wish to pursue.

Q. Have the Companies struggled to maintain or increase cost-effective EE savings for individual programs as well as the overall EE portfolio?

A. So there's a number of things that go into how cost-effectiveness for programs are determined, and every year presents its own set of distinct points in time where -- so take, for example, avoided costs. Currently, the avoided costs for cost-effectiveness purposes is dependent on the avoided cost proceedings that are handled outside of the DSM/EE proceedings. But those are initiated and the Commission rules on --

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in those proceedings every two years or so.

But every time avoided costs -- an avoided cost proceeding concludes, that initiates the change in underlying of what it costs for purposes of determining cost-effectiveness. So that is an example -- I mean, avoided costs are just one example of how challenging it is to keep cost-effectiveness for individual programs above 1.0.

Q. Thank you. No further questions.

CROSS EXAMINATION BY MR. SNOWDEN:

Q. Good afternoon, gentlemen. Ben Snowden for CPSA. Nice to see you. I'd like to follow up on a couple of questions my colleagues have been asking.

First of all, on the social cost of carbon, Mr. Thomas, you referenced the Governor's Executive Order with reference to the social cost of carbon, didn't you?

A. (Jeff Thomas) I did.

Q. Okay. But would you agree that the social cost of carbon figure that the Public Staff relied on in its testimony is not the same social cost of carbon figure that is referenced in the Governor's Executive Order?

A. I don't believe so. The Executive Order

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1 references a particular report, and that is a report
2 that I pulled to arrive at that social cost of the
3 carbon.
4 Q. Okay. Well, now, the Governor's executive
5 order references a revision to the social cost of
6 carbon figure that was expected in 2022, doesn't it?
7 A. I believe so. I don't remember -- I don't
8 think it was released by the time we put together our
9 comments, although I don't remember quite -- let me see
10 here.
11 Q. Yeah, I don't think it's referenced in your
12 comments.
13 A. Okay. Yeah. We use the report -- I don't
14 recall if the revision was released at the time we put
15 this together.
16 Q. Okay. Well, would you agree that the
17 intergovernmental working group's work on the social
18 cost of carbon revision was delayed because of
19 litigation; are you aware of that?
20 A. I'm not.
21 Q. Okay. So are you not aware of whether that
22 work is continued and whether the revision that was
23 expected is currently underway?
24 A. I am not aware of the progress of that, that

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technical panel.

Q. Okay. Have you reviewed CPSA's comments on this issue?

A. You'd have to remind me or put me in a --

Q. Okay. This is -- and I don't want to get too deeply into this, because this is in the written comments, but have you reviewed CPSA's discussion of the social cost of carbon and the figure for the social cost of carbon that the Governor's Executive Order was actually referencing?

A. I believe I -- I recall those -- that discussion, but I've read a lot of comments and testimony, and I'll be honest, I don't recall the precise --

Q. Okay. All right. I'll move on, then. I would like to follow up on -- I guess this is CIGFUR's Cross Examination Exhibit 2, the chart of annual CO2 emissions reductions.

Would you take a look at that?

A. Yeah.

Q. Okay. So would you agree that P1 on this chart doesn't just achieve compliance with 70 percent earlier than the other portfolios, but achieves greater greenhouse gas reductions in almost every year if not

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every year of the planning period?

A. Yes. And that is partially -- to a certain extent, that's partially a way of how Duke modeled the interim compliance. So they extrapolated from when the target began in 2025 or, I think, 2026 to 20 -- to the interim date, and then they extrapolate it from there to the end point. So partially this is kind of a modeling artifact, but yes.

Q. Okay. Thank you. So what you're saying is that Duke designed the portfolio, P1, not just to achieve earlier compliance, but to achieve in a way that achieved a higher level of carbon abatement than all of the other portfolios in every year, even after 2030?

MS. CRESS: I would object, Chair Mitchell, to Counsel's characterization of this witness's testimony.

MR. SNOWDEN: I'm asking him if he agrees with how I've characterized the way this model is -- or the way the portfolios are designed.

CHAIR MITCHELL: I'm gonna overrule the objection.

THE WITNESS: Yeah, I think the numbers don't lie. I think P1 emits less carbon than any

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other portfolio.

Q. And would you agree that carbon abatement, for lack of a better word, costs money?

A. Yes.

Q. Okay. So would you agree that, to a significant extent, the cost differential between P1 and the other portfolios here arises not from the fact that it achieves compliance in 2030, but from the fact that it achieves more carbon abatement all the way through 2050?

A. I'm not so sure that that's necessarily true. I think the way that the production cost models, and this output is from production cost models, and the way CAPEX -- the carbon cap was modeled and the capacity expansion model cause resource selection, I think that the higher cost is generally associated with the resources that were added over time.

But I also don't think that it would have been reasonable for Duke to say in P1 allow a lapse in the CO2 margin to level out with other portfolios. I understand they were trying to model an orderly transition from one point to the next.

And so yeah, I think that this is -- if anything, I think it's the earlier compliance, and then

marching from that earlier compliance on to the 2050 is partially the reason. And P1 has a shallower slope of decarbonization in the later years, which potentially could offset some of that increased cost that you were just referring to.

Q. Okay. But cost impacts in the later years are gonna have a much lower impact on PVRR of the portfolios, won't they?

A. Generally, yeah.

Q. Okay. So all I'm asking is, I mean, would you agree that the cost differential between P1 and the other portfolios isn't entirely a result of the fact that it achieves compliance in 2030 instead of a later year?

A. Well, I think that's the -- as you said, bigger costs are much more discounted. I think that's probably a primary driver, is the earlier compliance. But to the extent by which it's driven by a sustained lower carbon emission rate is -- it may contribute, but it's hard to tell.

Q. Okay. Thank you. I'd like to follow up on your discussion with Mr. Burns about cost overruns on solar.

Now, would you -- well, as I heard your

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testimony, you were saying that larger procurements of solar result in greater customer exposure to cost overruns; is that a fair characterization of your testimony?

A. I think if you procure 10 megawatts of a resource and you have a 10 percent cost overrun, that risk is less than if you procure 1,000 megawatts and you experience the same 10 percent cost overrun. So yes, the more of a particular resource you procure, if the cost overruns are similar, you could experience greater exposure to raw number of dollars that would be put onto ratepayers.

Q. Okay. Well, let me ask another question.

With respect to solar, who is exposed to cost overruns?

A. Well, I think the cost overruns, in terms of -- are you talking about construction cost overruns?

Q. Well, cost overruns was your phrase.

A. So I think, to a certain extent, right, the ratepayers are exposed to those potential cost overruns when developers, like, you know, competitive procurement, factor in those risks and contingencies in their bid price, right? Whether a developer has a stable environment and puts a 5 percent contingency in

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or has a very volatile environment and puts a 20 percent contingency in, those costs would go to ratepayers.

In terms of after the PPA has been selected, cost overruns relative to the bidder's price, the developer would be exposed to those cost overruns up to a point at which that developer, much as several projects in tranche 2 have done, simply decides to walk away from the PPA. And at that point, the ratepayer doesn't get any of the output from the facility, and the developer walks away with potentially, if the contract allows for it, liquidated engages. But that's always an option for the developer to walk away if those cost overruns reach a point where they're not tenable.

Q. Okay. Thank you for that. I think you and I maybe are using the word overrun in a different way. At the very beginning of your answer, you said there would be an overrun if a developer accounted for the risk of cost changes in their bid and they delivered on that bid. That does not sound like an overrun to me.

Would you agree with that?

A. If the cost estimates that the developer used in the development of its bid are met, no, that would

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not be a cost overrun.

Q. Okay. So if a developer's actual cost of development exceeded its bid, then it would be the developer that is exposed to that overrun, right?

A. Generally, but it depends on the RFP, if there's a big refresh mechanism or anything like that that would potentially allow those increased costs to be passed down to ratepayers. You know, that would put a risk on ratepayers.

Q. Okay. But as yet, no such bid refresh mechanism that would allow an upward adjustment exists under the RFP, does it?

A. I believe the 2020 RFP has downward-only adjustment, yes.

Q. Okay. So there is some ability for ratepayers to capture the benefits of any downward pricing changes during the RFP, but in no event would they be exposed to upward changes in cost during the RFP; is that right?

A. That's in this RFP. I think you're still gonna have the development of future RFPs. It's unclear what the parameters of those RFPs would be.

Q. Okay.

A. (Dustin Metz) Can I just add one thing?

It's also how, I mean, any facilities, not solar-specific because they're not interconnecting to the system. So to the extent there's transmission cost overruns associated with the project deployment, I mean, that's another risk factor to consider.

A. (Jeff Thomas) And also, you know, just to add onto that, that the cost overruns are not just for PPAs, right? 55 percent of this solar, of whatever quantify of solar is procured, will be utility owned. And to the extent that those cost overruns, you know, would fall on ratepayers, that would be incremental risk as well.

And, obviously, that would be something that the Public Staff and the Commission would review during cost recovery proceedings for prudency. But, you know, that would be a potential exposure to ratepayers on the utility ownership side.

Q. Thank you, Mr. Thomas. And I don't want to get too far into the details of the RFP, but as I understand it, under at least two out of the three structures that are allowed for utility ownership projects, it's just the developer who is exposed to cost overruns, and it's only if Duke serves as the EPC that ratepayers would be exposed to overruns; would you

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agree with that?

A. I'm not -- I'm not really -- I'd have to look over the IRP. I don't remember the three exact types of utility transfer, what they entail. I don't know what those contracts would look like, I would have to --

Q. Okay. Understood. But if an RFP bidder provided a set bid for the delivery of a turn-key project to Duke, it would be the bidder who was exposed to any cost overruns, wouldn't it?

A. Potentially, yeah. I think that would be most likely part of it. And then, obviously, if the developer were to walk away, that would be -- and always an option that they could potentially exercise if the cost overruns were excessive.

Q. Thank you for mentioning that. I do want to follow up.

You mentioned that a bidder who defaults on a PPA is exposed to liquidated damages; do you agree with that?

A. It depends on the contract and the PPA. I'm not a contract attorney. But yeah, my understanding is that generally there are some form of liquidated damages.

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Q. Okay. Thanks. And to be clear, I'm just talking about the current -- let's use the current RFP contract structure to work off of.

Would you agree that for -- that those liquidated damages would run into the multiple millions of dollars, depending on the size of the project?

A. I suppose they could. Like I said --

A. (Dustin Metz) We don't have the contract in front of us.

Q. Understood. Thank you. Would you also agree, though, that if a -- if a developer were selected in RFP, moved to the DISIS process and withdrew after signing that PPA, they would also be --

MR. JOSEY: I'm gonna go ahead and object to this line of questioning. I mean, we're getting into -- we've gone several questions into how the RFP works. This is the Carbon Plan proceeding. We're trying to determine the amount of megawatts selected, not how they're selected.

MR. SNOWDEN: Mr. Thomas raised -- the issue of execution risk has been a pretty important one in this docket. Mr. Thomas has talked a bit about the risks of nondelivery by bidders. This is, I think, my last question in this line of

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cross, but I definitely think this is highly relevant to what the Commission is being called on to decide.

CHAIR MITCHELL: All right. I'm gonna overrule the objection, allow you to ask this last question.

Q. Okay. Mr. Thomas, would agree that bidders in the RFP have fairly strong incentives to price their projects in a way that accounts for the risk of cost increases so they don't get stuck with liquidated damages or other penalties?

A. (Jeff Thomas) I certainly think that's probably a factor in how they develop their bids and what type of contingencies they include in their bid price.

Q. Thank you. All right. I'll move on from there.

Mr. Thomas, would you agree -- do you agree with, or does the Public Staff agree with Duke's general approach to the Carbon Plan of including a reasonable range of portfolios and then seeking approval for a Near-Term Execution Plan that supports all of those portfolios?

A. I think -- and I state this on page 6 and 7

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of my testimony. I believe that Duke's approach, right, of the multiple pathways and portfolios, sophisticated optimization tools determine those capacity expansion plans, proper input data and the identification of a Near-Term Action Plan is reasonable.

I don't necessarily think that the Near-Term Action Plan needs to cover every conceivable sensitivity and portfolio uncertainty that might be modeled. There's quite a few sensitivity analyses that Duke performed, and more that they may perform in the future. So I just -- I think that the Near-Term Action Plan is a reasonable step, to the extent that it aligns with the general goals of where we're trying to get.

Q. Okay. Understanding that sensitivities are not the same as portfolios, would you agree that the Near-Term Action Plan should support or be consistent with all of the portfolios that are actually included in the Carbon Plan?

A. Well, I'd maybe hesitate on that, because I don't believe that Duke has justified a delay beyond 2032. So I think that, you know, kind of reviewing the -- all the portfolios, I think that P3 and P4 were very -- and SP6 were very illustrative and, kind of,

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demonstrating what that additional delay would be, what that would look like. But I think what I said in my testimony, that Duke has not yet justified that according to 951.

So to the extent that a portfolio is more reasonable modeling that has been done, I think that's -- that's fair. But I'd also point out there's significant differences and changes from P1 through P4 and SP5 and 6. And so to the extent that our near-term action plan is really looking at SP5 is because, in my opinion, there were material improvements to the modeling methodologies and more reasonable assumptions on natural gas supply that we pushed for in SP5 to the point where SP5 is kind of its own portfolio.

And perhaps if we had more time we would have seen those modeling -- those modeling assumptions in SP5 play out in a variety of different sensitivities, much like P1 through P4 and P1-A through P4-A. But to the extent that -- it's kind of a different portfolio, in terms of the inputs and the methodology, and we support those. And that's why we, kind of, pointed at the SP5-compliant Near-Term Action Plan rather than a universal action plan.

Q. So the Near-Term Action Plan you believe

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should support SP5?

A. Yeah. I think I labeled it SP5 compliant in my table 3.

Q. And when does SP5 achieve compliance with the 70 percent reduction requirement?

A. No later than 2032.

Q. Okay. And P1 is the only portfolio that achieves compliance in 2030, right?

A. Yes.

Q. Okay. Does the Near-Term Execution Plan support P1?

A. I think the Near-Term Action Plan, and particularly our recommendations about the 2022 solar procurement, the quantity that we recommend there, could put us on a least-regrets path there. But, obviously, a lot needs to be, kind of, reviewed in the 2023 update and the 2024 Carbon Plan.

And I think -- I don't think that if we follow the 2022 solar -- if the Commission approves our recommended volume for the 2022 procurement, I don't believe, based upon the annual additions -- we've almost kind of, front-loaded it slightly from the actual resources selected in SP5 in 2026. So I believe that that puts us on a path towards compliance no later

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than 2032.

But like I said, I think the Commission needs to carefully consider its discretion and the optimal time and trade-offs between 2030 and 2032 compliance when making its decision.

Q. So, Mr. Thomas, I heard you say that the Near-Term Execution Plan, as you recommend it, potentially puts us on a pathway to compliance in 2032; is that what you said?

A. I think -- I think it generally could. I think some of your resource recommendations, like I said, are slightly front-loaded and I think we're gonna be revisiting this and looking at hopefully some updated modeling in the 2023 IRP update. But yeah, I think SP5 compliant, that Near-Term Action Plan and the specific numbers for the 2022 RFP would support a compliance date of no later than 2032.

Q. Okay. So the Near-Term Execution Plan the Public Staff recommends does not put us on a pathway for compliance in 2030; is that correct?

A. I think there's a lot of factors to consider there. I think -- I certainly think that it could, if we are able to execute better on interconnection limits, on onshore wind procurement than expected, I

think we could get there. If we have a mild weather year in 2031 or 2030, we might get there even earlier.

I think a lot depends on system conditions and the success of this RFP and the success of the red zone upgrades and other transmission-constraint alleviation. So I think we're trying to get there by no later than 2032, but I believe that we're trying to set up the system with some of the recommendations on a transmission plan that Mr. Metz has discussed.

We're trying to get there by no later, and that -- if we can get there by 2030, that's great, but I think we need to weigh and balance not only the carbon reduction but also the costs, reliability and execution risk.

A. (Dustin Metz) And another function not being picked up in the -- Mr. Thomas' table were sort of the volume adjustment mechanisms that we had within the 2022 RFP, which is Commission approved. There could be -- if solar or any resource that we seek procurement for comes in lower than the reference cost, depending upon what metric or percentage we use for that adjustment, we will continue to procure those carbon-free resources at a higher volume.

So that's why we're saying no later than

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2032. We believe that we're in a framework to set ourselves up for success to get us there in a proper glide path.

Q. Do you believe that Duke should be trying to achieve compliance in 2030?

A. (Jeff Thomas) I think we've looked at P1 and the 2030 compliance, and I think we have concerns, and I think I've enumerated those in our comments and my testimony. I think that the risk of extraordinary cost increases to North Carolina ratepayers associated with 2032 -- 2030 compliance has to be a factor in our transition.

And so that's why we've recommended 2032, Duke no later than 2032, but I believe I'd recommend that Duke take all the measures that they can to achieve compliance by 2030, or at least no later than 2032.

Q. Mr. Thomas, let me ask you, what would happen if we tried to achieve compliance with 2030 but we didn't get there on time because we couldn't hit the solar interconnection targets that were projected, say, for P1?

A. I imagine that, depending on -- depending on load and weather and how other resources are

interconnect and operated, all else equal, we'd probably achieve it at later date. But a lot depends on coal retirement, new gas resources, and other factors in the system operations.

Q. Okay. So what I'm hearing you say is that, if we shot for 2030 and we couldn't achieve it, we'd just achieve compliance a little later.

Is that a fair characterization of what you said?

A. I think there is a risk that if we -- I would agree that, generally, if you shoot for 2030 and you miss, you would land later. But I also would point out that, by shooting for 2030 and missing, you might incur substantial costs to ratepayers associated with that attempt that would, you know, cause significant cost increases for ratepayers that are already -- many who are already struggling to pay their bills.

And so I think we have to factor that in to a certain extent in the system that we plan going forward.

Q. I hesitate to ask this question, but what kind of cost increases are you talking about that we would incur if we set a more ambitious target, say, for solar interconnection and just didn't get there?

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A. I think it's more than just solar interconnection. It's battery storage deployment, it's operation of particular resources that are already on the grid, it's, you know, solar plus storage contract development, it's onshore -- to a certain extent, I think P1 relied upon -- well, not by 2030, by 2032.

But there's a lot that goes into simply developing and running those. And if you procure -- you know, if you procure resources that are delayed in interconnection, right, I think that there is a risk that, by procuring that resource in, say, 2022 and locking in a PPA in 2023 when you select that winter, because you've expanded that volume, I think if you were to shoot for 2,000 megawatts in the 2022 procurement, I mean, that would cause significant problems with then your -- you know, you're ranking your RFP, you're selecting the projects as you go up.

At a certain point, you're selecting projects that are the most expensive in that RFP and you're signing PPAs with them. And then if they're delayed coming online and you end up missing your interim target anyway, you're still paying the higher price that you procured because of the way the RFPs go from most cost-effective to least cost-effective, so.

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Q. Mr. Thomas, how many megawatts in are the 2022 solar RFP, if you recall?

A. Right now it has a floor, I think, of 700 megawatts.

Q. I'm sorry. Not the target, but do you recall Ms. Farver's testimony about the 2022 solar RFP?

A. Yes. Yes.

Q. Okay.

CHAIR MITCHELL: Are we getting into confidential information there? Because it's identified in your testimony as being confidential.

MR. SNOWDEN: I believe that Duke has said that the pricing is confidential, and I don't plan to ask about that. I believe Ms. Farver testified nonconfidentially about the number of megawatts. Please correct me if I'm mistaken about that.

MR. JOSEY: I would say -- yeah. I would say that maybe the number of megawatts that bid into is confidential, but the number of megawatts in the DISIS is not. I'm looking for Duke.

MR. BREITSCHWERDT: The rebuttal testimony of the Transmission Panel and solar panel

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speaks to approximately 4,900 megawatts bidding into 2022's solar procurement. So I think we can stipulate that that is public. But any granularity beyond that we would say is confidential. Thank you, Chair, for flagging that, we're agreeable that's appropriate.

MR. SNOWDEN: Thank you, Mr. Breitschwerdt, I appreciate that.

Q. So subject to check, about 4,900 megawatts have bid into the 2022 solar RFP?

A. Yes.

Q. Okay. So even if the Commission were to direct the procurement of 2,500 megawatts, which I believe is well in excess of what anyone suggests, you still would only be getting to, sort of, the halfway point, in terms of bid prices, right?

A. You'd be getting to the halfway points in megawatts, but I can't say that's the halfway point in bid prices.

Q. Understood.

A. (Dustin Metz) I would like, if I could, to come back a little bit. I didn't get a chance to answer when we were talking about the potential risks if we shoot too early. I covered some of this in my

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testimony.

The coal exit strategy, as I sort of characterize in my testimony, if we start planning to shut down some of these generation plants and we can't meet the RFP targets that we're set an aggressive goal for, there's a balance. And I think that's what we're trying to achieve here.

So when we talked about risks, if we want to start going after these aggressive targets and we start accelerating the coal retirements and we miss our targets, then I would say there's functions of reliability that need to be taken into consideration.

Q. But Duke wouldn't retire a coal plant if there weren't sufficient replacement resources, would it?

A. It would depend on function. I mean, for example, I mean, the overall Allen units were retired, and yet some of the transmission upgrades are underway. I believe that's why Allen Units 1 and 5 are still online while they're doing a transmission upgrade. But to the extent that Duke needs to -- again, from planning and modeling standpoint, if a resource is no longer required, I mean, I guess our expectation in isolation would be that Duke should be planning to

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start shutting down that plant.

Q. But if Duke can't procure or interconnect as much solar as it expects to, it can check and adjust, right?

A. It can check and adjust, but then we have to run that plant longer uneconomically, and after Duke had do multiple years when they look out multiple years in advance for fuel supply.

Q. Is that any worse than just planning to retire it at a later date, as Duke might with a 2032 or 2034 compliance portfolio?

A. No. I believe that's part of the balance that we're looking at here.

Q. Thank you. Mr. Thomas, I want to direct your attention to page 12 of your testimony starting on line 17.

A. (Jeff Thomas) Okay. I'm there.

Q. And do you see on page 17 -- I'm sorry, line 17, you say that, "Only after Duke" -- sorry about that. Let me start that again. On line 17, you say that, "Only after Duke has demonstrated that the interconnection of sufficient resources to meet the interim compliance date by 2030 is not possible, ideally through the results of the 2022 and 2023 DISIS

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cluster studies."

I'm sorry, I -- do you see where you said that? I'm afraid I --

A. Yes.

Q. I didn't quite take the full text of that. I apologize.

A. Yeah. So I'm talking here about the -- recommending the delay in the interim compliance and the Commission's discretion.

Q. Okay. But do you still agree that, in order for this Commission to authorize delay past 2030, Duke has to demonstrate that interconnection is insufficient?

A. I think that that would be helpful for the Commission to weigh into its decision on whether to delay the compliance or not. As I said before, I think that the -- I think that the near-term actions, particularly as it relates to the 2022 solar procurement, will be the procurement volume, will at least put us on the path for 2030 compliance, particularly around storage and the shift to solar plus storage.

And I think that we'll know when the 2022 DISIS closes and we start to see those results come in,

what kind of construction timelines are estimated, particularly for transmission upgrades. I think that will be informative to whether or not the -- whether or not Duke is even capable of meeting compliance earlier than by 2030.

Q. So as I read your testimony, you seem to be saying that the Commission shouldn't authorize Duke to go even past 2030 until the results of the 2022 and 2023 DISIS studies show that compliance by 2030 is impossible. Is that a fair characterization of your testimony?

A. I think that's -- that's what I'm saying here. I think that, in the next few pages, I talk a little bit more about the execution risk that the Commission should weigh. And I did a little bit of discussion about what the cost and -- the cost factors that the Commission should consider as well.

But here I think that this information is -- it would be informative to the Commission, but I think that the determination on actually approving a 2032 compliance date, saying in their order that Duke should seek compliance by 2032 as opposed to no later than 2032, I think that needs to be -- potentially would be helpful to be informed by interconnection studies and

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those types of timelines to see where we are in terms of capability.

Q. So would you agree that, until Duke shows, through the results of DISIS, that it cannot achieve the 2030 carbon reduction goal, the Commission should be directing Duke to engage in activities that would be consistent with achieving compliance by 2030?

A. I think that the -- I guess maybe there's a difference here between no later than 2032 and requiring 2030 compliance. I think saying delaying until 2032 may allow the Commission to develop a Carbon Plan with lower costs and execution risks, and I think that's an important factor. But I think that ultimately the Commission's Carbon Plan should -- should require Duke to take the steps necessary to achieve compliance no later than 2032, factoring into its decision costs, reliability, and execution risk.

Q. Thank you. One question on this. In your testimony -- in your prior testimony, I think it might have been in response to Mr. Burns' question, you talked about SMRs. And you said that we need to put SMRs in context. Do you recall that? And a 300-megawatt SMR is not a huge amount on a system as large as Duke's; do you recall that?

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A. Yeah. I think in terms of capacity, it's fairly small. It appears to be necessary to meet that -- those compliance dates. And it certainly produces significantly more carbon-free energy than a 300-megawatt solar facility. But yes, that's what I testified to.

Q. Okay. Well, let me ask you this. Do you think it would be --

CHAIR MITCHELL: All right. Let me interrupt you, Mr. Snowden. We're gonna pause for our afternoon break. We will take a 15-minute break and be back on the record at 3:15. Let's go off the record, please.

(At this time, a recess was taken from 3:00 p.m. to 3:16 p.m.)

CHAIR MITCHELL: Let's go back on the record, please. Mr. Snowden.

MR. SNOWDEN: Thank you, Chair Mitchell.

Q. Gentlemen, you'll be happy to hear that I spent the last 10 minutes putting big black lines across my pages, so we'll try to proceed expeditiously. Mr. Thomas, I think this question is for you. I'd like to direct your attention to page 55 of your testimony, lines 3 to 5. Yeah, this is your testimony.

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And you say here that, "Modeling performed by the Public Staff suggests that resource selection in the near term is not particularly sensitive to resource prices, particularly for renewables and storage."

Do you see that?

A. Yes.

Q. What do you mean by that?

A. I explain a little bit more in there, but I think, in the near term, at least, you know, in the next three or four years, the resource selection is, you know, driving full tilt to reach that interim compliance. So what's really important there is what's driving a lot of resource selection is not the cost necessary -- I mean, cost is a component, but the carbon characteristics of those resources, and the then the resource -- the cap on the carbon emissions, and then the characteristics of those resources as they, you know, contribute towards meeting those carbon reduction goals.

So we have an EnCompass license and we played around a little bit with some of the inputs for SP5. We didn't have much time, but changing resource costs. And we found that there was really -- you know, changing renewable and storage costs pretty

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significantly, and, I mean, over the long term it did, obviously, affect the resource that were selected. But in the near term, you know, you're really -- you're already maxing out your solar. You could drop the price of your solar to $0 a kW and you're not able to select any more because of the interconnection limits, right?

So I think there was very little deviation there, particularly with storage, and I think some of the other resources that we modeled.

A. (Dustin Metz) I mean, and for context -- and Mr. Thomas may say this better than me -- but we also looked at sort of SMR costs. Remember I was talking about the EI, how I entered the EI data from 2021 and '22, and we did do an adjustment up to 18 percent?

A. (Jeff Thomas) 18 percent, yes.

A. (Dustin Metz) We increased the price by 18 percent, and it was still economically selecting the model. So we continued to evaluate, sort of, push-pull concepts within the EnCompass license to see if any material changes would occur around the fringes.

Q. Thank you. So what I'm hearing you say is that, in the near-term, even if the prices for renewables and storage were significantly higher or

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significantly lower, the model would still be selecting the same amount; is that right?

A. (Jeff Thomas) Yeah, I mean -- I mean, generally. There's, obviously, small deviations. I think we saw, you know, maybe a couple-hundred megawatts difference over the near term. I don't remember the exact number. But, you know, I think there's only one -- at this near term, there's only a couple different resources that are able to meet the carbon reduction goals.

You know, you're not building any new nuclear between now and 2030. There's, you know, onshore wind, offshore wind, and solar. And that's essentially the resources that are available to the model in that very near term. So when you're already hitting your interconnection limits on an annual basis for offshore wind, for solar, reducing or changing those costs in the face of a carbon constraint is not gonna be a huge factor in the selection of those resources.

Q. So a 10 percent change in -- upward change in solar prices wouldn't affect the amount selected by the model at all, would it?

A. I think we actually tested a downward change of, like, 30 percent to see if it was driving changes.

But I would expect that, with all the other resources essentially being maxed out, a 10 percent increase in the cost of solar would certainly increase the PVRR of the facility -- of the portfolio, but -- and the cost to ratepayers and the bill impact, but would not really materially select the number of megawatts potentially in the model.

Q. Thank you. I want to ask you very briefly about the volume adjustment mechanism for the 2022 RFP.

Are you familiar with that?

A. Yes.

Q. Okay. And so basically, under the volume adjustment mechanism, if solar prices in the RFP are 10 percent higher than the solar reference price that's projected by Duke, the volume goes down by 20 percent, right?

A. Yes.

Q. And conversely, if solar prices are 10 percent lower than projected, the volume goes up by 20 percent; is that right?

A. Yes, I believe that's right.

Q. Okay. And you just testified that you wouldn't expect a 10 percent change either way in pricing to affect what the model would select, in terms

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of solar resources, right?

A. So the model is constrained by the interconnection limits. If we had recommended a procurement volume in the 2022 solar procurement that exactly matched the amount of solar that was selected in 2026, 750 megawatts, that would be one thing. And I think, you know, an upward or downward would maybe not be material. But we've recommended here a target of 1,200 megawatts, significantly above that model selected interconnection limit in the near term.

So yes, the volume adjustment mechanism, we believe, is an important mechanism there to protect ratepayers from potential higher costs relative to the model costs while still maintaining some optionality, in terms of reaching that goal a little bit earlier, or accommodating that price increase.

So I don't want to tie exactly the modeling results, the VAM, because, you know, modeling world and the RFP world where the rubber hits the road and contracts are signed and ground is broken are very different things.

Q. Thank you for that. Now, by increasing the amount of solar in the RFP, you would agree that you do, to some extent, increase the execution risk by

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procuring more; is that fair to say?

A. Yes. And that's part of the balancing act of the three-legged school, if you will, of cost execution or cost -- I guess cost and execution, reliability, and carbon reduction.

Q. Okay. And that's sort of what I'm getting at.

As I understand the intent of the volume mechanism, what you're saying is the Public Staff believes that it's appropriate to take on a little bit more execution risk if that creates opportunities for greater savings for ratepayers; is that right?

A. Yeah, I think that's appropriate. If the costs in the RFP come in significantly lower than expected, then that's great. If developers are able to secure those low prices, I think that's grounds for increasing the amount and incrementally increasing the execution risk. But like I said, it's a balancing act.

A. (Dustin Metz) And it is the iterative nature of the Carbon Plan, to the extent that we procure -- and correct me if I'm wrong, but to the extent that we procure more resources in the earlier years due to volume adjusted mechanism after the fact, the track and adjust, so in future years, depending on how the costs

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come in at, we could be procuring less solar, in this hypothetical example, on resources.

Q. Thank you. Mr. Metz, I want to talk for just a minute about -- actually, this would be for Mr. Metz and Mr. Thomas. I want to talk for a minute about Duke's model solar interconnection constraint.

Would you agree, with Mr. Kalemba's characterization, that the interconnection constraint represents Duke's forecast of the most likely rate of interconnection that you can achieve?

A. Can you point me to where he said -- are you characterizing his testimony or --

Q. Let me ask another way. Did you hear -- and I understand if you don't remember it all.

Did you tune in for any of Mr. Kalemba's testimony on the stand?

A. Yes, I did.

Q. Okay. Do you recall a discussion where we talked about Mr. Kalemba's characterization of the solar interconnection constraint as a forecast of how much solar Duke thought that it could actually interconnect?

A. I can't recall the exact conversations, but yes, the interconnection limit is a forecast.

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Q. Okay. And I'm gonna skip a ton of questions here and just ask, would you agree that there is just a fundamental uncertainty about how much solar Duke will be able to interconnect over the course of the next several years?

A. Yes. And many of those factors are outside of Duke's control, in my opinion. I mean, if we look at how we're gonna perform this solar procurement, I mean, pretty much defined by 951, it's worse -- where generation wants to locate is essentially how we're having to build the transmission system around it. And I don't mean that in a negative way, that's just the realities that we hear.

So to the extent that larger and larger upgrades occur, it could take more time to implement those upgrades to ensure system reliability.

Q. And you just testified that some of the factors that impacted interconnection rates are outside of Duke's control.

Would you also agree that some of the factors that impact interconnection rates are also within Duke's control?

A. Yes, I would agree.

Q. Thank you. Mr. Thomas, did you see Brattle's

analysis in CPSA's comments stating that Duke's interconnection cost -- I'm sorry, that Duke's interconnection constraint would raise the annual price of the portfolio by several hundred million dollars?

A. (Jeff Thomas) I'm familiar with that concept. But I would just reiterate for the Commission that any binding constraint at all that you put on the model is going to increase costs relative to that unconstrained portfolio. That goes for any constraint, whether it's a constraint on natural gas supply access, the number of plants you can build per year or the interflows between DEC and DEP. So all that, if they're binding, they're increasing costs. That's a simple concept of linear optimization.

Q. So when you say "binding," what do you mean?

A. The limit is reached.

Q. Okay. So a constraint only increases costs if it results in the model selecting higher priced resources; is that a fair characterization?

A. If a constraint of 750 megawatts of solar added in a particular year is reached, and the model selects 750 and it would have selected more in the absence of that constraint, that would increase costs, all else equal.



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A. (Dustin Metz) And another example, I mean, focusing on constraint is how Duke set up the EnCompass run as looking at real-life interties that sort of exits between DEC and DEP. And this is in our initial comments and it's in one of the figures, I can't recall it off the top of my head, is there's a physical limit that we live in today, how much energy can flow from DEP to DEC.

Now, that is a physical constraint. And I'm glad that Duke modeled that constraint, because that's a physical reality that system operators have to work with every day. If we lifted that constraint and disallowed energy unconstrained to flow from one utility to the other, we'd be setting ourselves up for reliability issues.

And it's my understanding, coming out of the Brattle model, is that it was a joint BA, so in other words, there was no physical constraint on the amount of energy that can flow between the two areas. So when we look at what resources are being selected, constraints -- as Mr. Thomas stated, constraints are binding, but we evaluate whether they're reasonable or not.

Q. Okay. Understanding that there is, in

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reality, some limit to the amount of solar or any resource that Duke can interconnect in a given period of time, are you aware of any analysis that contradicts Brattle's basic point, that limiting the amount of solar that can be interconnected increases the cost of the portfolio?

A. (Jeff Thomas) So I think that, you know, as far as the portfolio, the modeled costs, yeah, I think that -- you know, like I said before, a binding constraint will increase costs. But, you know, I think that -- and I spoke a little bit about this before, you know, solar RFPs have a -- will have a range of price, right, but bidding in all sorts of prices.

The modeled costs compared to those prices are going to be different. They're just -- the assumptions made in the model are not the assumptions in the real world today, and there's going to be mismatches in assumptions about future cost increases and developers versus Duke. And those bids will reflect that.

And so, all else equal, procuring more of a resource in a competitive procurement will raise the weighted cost of the -- that resource that's been procured through the RFP. That's just simple math. So

I think that, while Brattle's contention is right in the modeling world, I think we need to make sure we're tempering that with an understanding of what can be done and what's the effect of that as well.

Q. Would you agree that, if there is the potential to achieve greater ratepayer savings, we should be investigating whether Duke can achieve higher solar interconnection rates?

A. Oh, absolutely. And I think Duke, you know, has its work cut out for it, in terms of interconnection rates. Subject to check, but I believe, in discovery, from 2019 to 2021, in those three years, Duke only was able to interconnect approximately 300 megawatts of solar across its combined system. That's a significant fall from 2016 or 2015, 2016 when they were able to connect over 700 megawatts.

But there's reason for that, right? And it reflects the reality of the system and these more triggered transmission upgrades and the challenges associated with moving from small distribution facilities that have no transmission impacts to small distribution facilities that have major transmission impacts. And they're small transmission impacts. And

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now the next phase is large transmission projects that have large transmission impacts.

So I think pretending that it's going to be easy to hit the baseline assumptions in Duke's model is naive. I think it's going to be a huge challenge just to get to the baseline, and then even to move beyond that and to get to the more ambitious solar interconnection constraints used by some of the solar intervenors is -- I mean, that's -- even on top of that is additional -- you know, is problematic, in terms of exposure to that risk.

A. (Dustin Metz) And to get there -- and I'm not -- this isn't quantified, but there's a premium to get to that extra level interconnection. To the extent that the Commission finds that they want to achieve these goals, they'd have to go back and look and say, okay, what is now the incremental transmission cost to continue to march this timeline. I don't -- based upon my review, that isn't quantified right now.

A. (Jeff Thomas) And I would just add one more thing. I don't believe that the CPSA interconnection limits and the interconnection cost adders that they use for the solar resources reflected that increased need for -- you know, the first tranche of solar might

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cost X dollars a watt in terms of transmission upgrades, but that next tranche and the next tranche and these higher and higher levels might -- they might see larger increases in terms of cost, if you're starting to trigger affected system studies and you're starting to have wide-ranging impacts that extend beyond the local network that it's being interconnected to.

So I don't believe that that was reflected in CPSA's study. So the contention that higher solar interconnection rates necessarily means lower cost to ratepayers, I don't -- I don't draw that conclusion.

Q. Well, Mr. Thomas, you would agree that all the portfolios that are under consideration eventually result in the addition of in excess of 10 gigawatts or more of solar generation on Duke's system, right?

A. Yes. Obviously, there's a difference in the pace, you know, the orderliness of the transition, so.

Q. So --

A. (Dustin Metz) And I want to add, it's also -- 10 gigawatts, from a modeling standpoint, it's a model, it's not where it's actually locating at, and that's sort of some of the differences in the model. From terms of EnCompass and Duke's plan and some of the

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supplemental portfolios, it's this 40 percent -- 40/60 split, 40 percent is located in DEC and 60 percent is located in DEP.

If we oversimplify the model and just say you can go build it anywhere -- let's say again, hypothetically, that that 10 gigawatts, regardless of BA -- and let's say we look down the road at a merged utility. If we go locate that 10 gigawatts over in a concentration in any part of the system, you're gonna have transmission impacts larger the amount of generation, exceedance of load, you're gonna have new transmission impact, new transmission requirements that we haven't even seen yet today.

Q. Would you agree that, given the amount of solar that is ultimately gonna be going on the system to achieve compliance, that the amount of near-term solar that CPSA, all of the parties are proposing, is ultimately gonna be required, isn't it?

A. (Jeff Thomas) I mean, I think there's differences in the near-term procurement volumes.

Q. Understood. But we know we're gonna need at least that amount of solar, it's just a question of when?

A. (Dustin Metz) And also where.

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Q. Understood. Appreciate that.

A. (Jeff Thomas) I mean, I know over my life I'll probably need three or four vehicles. I don't go buy them all today, right?

Q. Understood. Okay. We're almost finished here.

Mr. Thomas, did you hear Mr. Snider's testimony when he was on the Modeling Panel about what he characterized as the risk of an over-procurement?

A. I was there for that. If there's a particular risk you want to discuss, maybe you could --

Q. Okay. I'm just trying to set the stage. And I do want to clarify something. If solar is procured through an RFP, neither Duke nor ratepayers actually pay anything for it until it actually goes online or is sold to Duke in the case of utility ownership, right?

A. I think there is the power, the output, yeah. I think once -- the PPA, you don't pay anything for the PPA until the power is delivered, but you may build transmission upgrades or even potentially interconnection facilities in advance of that facility achieving COD, and those costs would be incurred whether or not the PPA was -- you know, began delivering power.

Q. But interconnection facilities are paid for by interconnection customers, right?

A. Yes, but not network upgrades.

Q. Understood. Well, I'm not sure we've established that.

A. Yet.

Q. Yet. Okay. Does the Public Staff think that it makes sense to delay procurement of solar in the hope of achieving greater cost savings on solar or storage in a few years?

A. I think the near-term procurement, and particularly the 2022 solar procurement volume that we've suggested, appropriately balances the risks of waiting and the risks of moving too early. I think portfolios that are suggesting significant amounts in the 2022 procurement run the risk of over-procuring and potentially paying those higher costs. While, obviously, waiting too long, you know, risks not meeting that compliance date and potential subject to future, you know, market uncertainties that could drive prices up.

I think the volume we've recommended and the volume adjustment mechanism for ratepayer protection that we've proposed adequately balances these factors.

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Q. And when you say those higher costs, though, there is no certainty as to whether solar costs will be higher or lower in subsequent years, right?

A. No, there's no certainty.

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

CHAIR MITCHELL: All right. We've got CUCA?

MR. QUINN: I believe I don't want to --

MR. TYNAN: CUCA waives its questions.

CHAIR MITCHELL: Okay. NC WARN.

MR. QUINN: Thank you very much.

CROSS EXAMINATION BY MR. QUINN:

Q. Gentlemen, good afternoon. My name is Matthew Quinn. I am the lawyer for NC WARN and Charlotte-Mecklenburg NAACP. I don't know if it's a blessing or a curse, but I'm going after a lot of lawyers who have asked a lot of good questions. So I'm gonna try to talk about maybe some topics that haven't been touched on yet. And, Mr. Thomas, I'd like to start the conversation with you, if I could.

My understanding of the Public Staff's, or your testimony, is that the Public Staff does not recommend any changes to Duke's forecast of natural gas

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prices; is that a correct understanding? This is on page 40 of your testimony, by the way.

A. (Jeff Thomas) Yes. Given the fact that we submitted this testimony in early September and the Commission has a deadline of late December, we did not feel -- and given that the natural gas resources selected in the model occur largely beyond any of these near-term procurement activities, we felt that updating the natural gas prices in this proceeding was not necessary at this time.

But we do recommend that, in future updates and CPCN proceedings, that updated natural gas pricing forecast be used to help justify the necessity and convenience of new natural gas resources.

Q. I appreciate that explanation, and you did a little bit anticipate where I was going to be going with this, so you might have streamlined our conversation just a little bit. But there are a few points I do want to touch on.

I think in your testimony, you do explain that there are some -- these are my words, not yours, but, I mean, there are concerns the Public Staff has concerning Duke's natural gas price forecast; is that a fair characterization?

A. I think we're -- mostly, I think we're acknowledging that price volatility that's been happening recently is not reflected in the forecast used in this model.

Q. In fact, would you agree with me that Duke's forecast of natural gas prices never anticipates that those natural gas prices will get as high as the levels of natural gas are today; is that correct?

A. I mean, that's largely a function of the pricing forecasts that are used in their model, right, but I don't think the EIA with McKinsey, I don't think any of those forecasters anticipated the price hikes.

Q. Okay. And that's one reason why you do recommend -- I mean, I know you're not recommending it right now, but you do recommend, moving forward, that Duke update its forecast, in light of where prices are right now?

A. Yes.

Q. Okay. And it is important that any forecast take account of current natural gas price trends; is that fair to say?

A. I'm sorry, say that again.

Q. Sure. I mean, would you agree with me that it's important that any natural gas forecast take into

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account recent trends in natural gas prices?

A. Yeah. I think -- I think generally, though, you know, the pricing -- the agencies that are putting together these fundamental price forecasts are not just looking at the next couple of years, they're looking at the longer term. And I think even the EIA is anticipating a reduction in natural gas prices and a levelling out over time.

Q. And I'm not gonna mark it as an exhibit. I don't think, you know, for time purposes it's necessary.

But, you know, would you agree with me that an exhibit presented by NC WARN, I think to the Modeling Panel, to the extent you know, showed that natural gas prices, at least in August of this year, were over $8?

A. Yes.

Q. Okay. And that's higher than Duke ever projected natural gas prices would be under its forecast; is that correct?

A. Yes, that's correct.

Q. Now, would you also agree with me that natural gas price volatility can create an asymmetrical risk to ratepayers?

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A. Yes. I think I talked about that a little in my testimony, that the risks of price over -- like higher prices than modeled are greater. But, you know, also I want to emphasize that, you know, the pricing forecasts generally return to that fundamental level and are expected to return to lower prices over time, by the time those new natural gas resources are selected.

Q. And I think -- this is on page 40 of your testimony if you want to look at it, but in your testimony, you -- I think you actually gave an example of how natural gas price volatility can create these risks to ratepayers, did you not?

A. Yes.

Q. Okay. And before I get to that example, would you agree with me that we are experiencing a period of natural gas volatility?

A. Yes.

Q. Okay. So what example did you give in your direct testimony concerning the risk to ratepayers in the event of natural gas price volatility?

A. I think you're referencing my, kind of, decision of Dominion Energy versus Duke; is that correct?

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Q. Yes.

A. So Dominion Energy, who is currently getting approximately 50 percent of its energy from natural gas, is seeing very significant under-recoveries in this year's fuel proceedings, versus Duke is only achieving approximately 30 percent today from natural gas. But then they go on to point out that, you know, while there is significant capacity from gas added, the total natural gas burned does go down over time, actually, in MMBtu, and that's in Figure 5 on page 43.

So to the extent that, you know, we are building some capacity, I think that there's certainly a reduction in the amount of gas that's being burned and the share of natural gas as a percentage of total energy consumption, which, all else equal, would reduce ratepayers' exposure to the natural gas volatility.

Q. Okay.

A. (Dustin Metz) I'd like to add, I mean, to -- from a cantilever force was also not represented there, or the energy rates at which Dominion has experienced with this 50 percent portfolio when natural gas prices were at their all-time low.

Q. Okay. And I think the point in your -- the example of Dominion is just to illustrate what the risk

can be to not properly -- of not properly forecasting natural gas prices and under-forecasting them, right?

A. (Jeff Thomas) I think the example I was specifically talking about was over-relying on natural gas simply as an energy resource. Which, as I point out, right, due to the heavy proliferation of carbon-free resources in all of Duke's portfolios, the natural gas is -- I mean, this chart on page 5 shows to me that natural gas is being used as a transition fuel, right? We're burning it now, and over time, as we add all these carbon-free resources, we're gonna burn it less, and that's the bridge.

Q. Okay. So I understand that explanation. I want to close the loop and then move on from this example of Dominion.

A. Sure.

Q. My understanding is another thing that you included in your testimony concerning this example, is that Dominion Energy is currently seeking a fuel deferral balance in Virginia of $1.02 billion; is that correct?

A. Yes, that's what my testimony says.

Q. Mr. Thomas, also on page 42 of your testimony, from lines 1 to 4, you testify, just in

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1 general terms, that these risks that we're talking
2 about are -- you say are acceptable because Duke -- and
3 this is a quote on line 3, "Significantly decreases the
4 total amount of natural gas burned annually."
5 Did I read that correctly?
6 A. Yes.
7 Q. Okay. Now, I hesitate to ask this question.
8 This is typically a question you do in a deposition,
9 not actually in the hearing room. But I'm just gonna
10 ask you because I'm curious.
11 You know, one of the decreases that you refer
12 to there, does that include Duke's proposal to
13 transition to green hydrogen?
14 A. So, in Figure 5, P1 through P4, this is
15 the -- P1 through P4 would include the -- it would
16 include hydrogen up until, I think, 2047 when full
17 hydrogen starts to be burned, so that's a different
18 chart. But SP5 and SP6 have no hydrogen, and so that's
19 the same, kind of, chart downwards as you see in the
20 other portfolios.
21 Q. Well, to the extent, then, that your --
22 sounds like for some of your portfolios or some of the
23 lines on that chart did indeed -- the decrease that
24 you're referring to in your testimony includes this

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proposed transition of the natural gas lead to green hydrogen, correct?

A. Yeah. I think what you're getting at is the P1 through P4 lines, as they go over time and the hydrogen blend increases, more of this natural gas is actually -- it's actually part hydrogen. So if you were actually to pull out that hydrogen component, they would see an even steeper decline in the volumes of CH4 natural gas that's burned. There's -- so I'm kind of showing both of them.

Q. So partly, I guess, then, is my -- I'm partly correct, then, that the decrease that you're talking about in your testimony is in part at least contingent upon the transition to -- of the natural gas fleet to green hydrogen; is that correct?

A. No, I don't think so. And I think SP5 and SP6 show that, even in the absence of hydrogen -- green hydrogen, you're still seeing that decline, because every time you add solar and wind and storage, those carbon-free low-dispatch stacked resources are displacing largely natural gas because there's nothing else to displace.

So gas is being displaced, we're burning less, and it's a transition fuel exactly, kind of --

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you know, that's how -- that's how I view this chart, that's the conclusion I came to.

Q. Okay. And would you -- would you agree with me that the Public Staff has advocated that it's premature to include hydrogen -- green hydrogen in Duke's modeling; is that correct?

A. Yes.

Q. Okay. I had a long discussion I wanted to go through about SMRs, I don't think that's necessary anymore, and a few other things. Let me move on to this topic, Mr. Thomas, and I think I'll stay with you.

My understanding is that the Public Staff believes that Duke's assumptions about EE/DSM and customer-sited generation are two aggressive; is that right?

A. I think I might defer to witness Williamson.

Q. Oh, that's perfect, yes. You haven't had a lot of chance to talk today, so.

A. (David Williamson) Could you repeat the question?

Q. Sure. Would you agree with me that the Public Staff believes that Duke's assumptions about EE/DSM and customer-sited generation are too aggressive?

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A. So I go at length in my testimony about the Public Staff's thoughts on the UEE forecast, but as far as the net metering behind-the-meter solar forecast, I believe we -- I believe early in my testimony that I pretty much say that we don't take issue with that forecast.

Q. Okay. Let me -- and -- first of all, Mr. Williamson, let me ask you this, because I do think this is part of your testimony, specifically on pages 8 through 9. Begins on page 8, line 17. You say, "The Public Staff agrees, in principle, that it is preferable to reduce the need to build capital-intensive resources through the use of cost-effective alternatives so long as system reliability is not compromised and those alternatives are least cost"; is that correct?

A. That's what it says.

Q. Okay. What kind -- what are you referring to when you say that, Mr. Williamson?

A. So the -- essentially, I guess, in particular to this -- as the load decreases --

Q. Yes.

A. -- it decreases the need to plan for resources in the future. That doesn't necessarily mean

that it will entirely wipe away the need for additional capacity, but as we proactively reduce load, the number of avenues we contribute to not having to plan for resources in the future.

Q. So it's a good thing to -- just as a general principle, as long as it's compliant with least cost, it's a good thing to reduce load through certain programs instead of building capital-intensive projects; is that correct?

A. As long as it fits the bill of least cost and doesn't impair system reliability in the long run, yes, I would generally agree.

Q. Okay. And, Mr. Thomas, I'd like to talk for just a second about a part of your testimony that appears on pages 56 and 57.

A. (Jeff Thomas) Okay. I'm there.

Q. Now, on these pages, Mr. Thomas, I think you're talking about Duke's modeling of, perhaps among other issues, also net -- net metering forecast; is that correct?

A. Yeah. I think I tried to focus more on how these resources are modeled.

Q. Yeah. And I think you made the point, did you not, in your testimony, that Duke's forecast did

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not take into account the proposed tariff changes pending in a separate docket; is that correct?

A. I believe that's correct.

Q. Okay. And you understand that these proposed tariff changes, they were proposed, some new charges upon net energy metering customers; you're aware of that?

A. Yes. I'm aware they're attempting to recover the full fixed cost of service for net metering customers.

Q. Okay. And we are gonna agree to disagree to that.

But my point being, there are gonna be new charges imposed upon net energy metering customers --

A. Yes.

Q. -- if the tariff were to be approved?

A. If the Commission approves it as filed, yes, there could be more --

Q. Mr. Thomas, is it possible that those new charges would reduce the savings for net energy metering customers?

A. Yeah, I think it's possible. I think there's a lot going on in that space in terms of solar, potential rebates that have also been proposed that

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have been attempted to blunt that. I'm not gonna get into all that. But I will just say, from the 2020 IRP to the 2022 Carbon Plan, Duke's projections for growth of net metering solar have significantly increased, almost doubling in year-over-year growth in DEC, and tripling in DEP.

So I think that the growth is being reflected hopefully there in that segment. But those tariffs have not been approved by the Commission and are not reflected in these estimates.

A. (David Williamson) So as a point of clarification, when you say "savings," who are you meaning in savings with respect to?

Q. The customer.

A. The customer.

Q. The roof on which the system is located.

A. Okay. Because the utility is experiencing savings and the customer is experiencing savings.

Q. Yeah. So I think -- any of you answer it, but I think this goes back to Mr. Thomas' testimony that we were looking at a moment ago. If it's possible the savings for these net energy metering customers are gonna be reduced, would you agree with me that it's also possible that the -- that that would have the

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effect of reducing the rate of growth of net energy metering solar in the state?

A. (Jeff Thomas) Yeah, I think that reduction savings for net metering customers could reduce adoption, an increase in module costs could reduce adoption. There's a lot of things that could reduce or accelerate adoption in net motoring, and not all of it is reflected in this -- these estimates.

Q. Mr. Thomas, I would like -- if you could please turn to page 57 in your testimony.

A. Yeah, I'm there.

Q. I want to talk about -- a little bit about footnote 71 that you put in your testimony. But before I do, I just want to give us a little bit of context for the discussion. I mean, I think the basic point -- and take as much time as you want to read this page of your testimony, but I think the basic point you're making before that footnote is you questioned how much net energy metering solar contributes to demand reduction.

I think that's what you were saying; is that correct?

A. The footnote specifically says that rooftop solar contributes very little, if any, of its capacity

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during winter morning peaks, which typically occur between 6:00 and 8:00 in the morning when solar is generally not generating. Particularly rooftop solar, which does not have tracking and is fixed tilt and has a significantly lower capacity factor than the utility-scale solar that's modeled here.

Q. And when you put that footnote, are you including within the scope of that footnote rooftop solar systems that are paired with some battery storage component?

A. I'm not. I'm not aware of -- my understanding is the vast majority of rooftop solar that's on the grid today is standalone, but I'm aware that that is -- that dynamic is changing.

Q. And I guess that was -- you anticipated what my next question was gonna be, but I'll just -- I'm a lawyer, so I can't help myself.

So would you agree with me, then, that dynamic is changing; in other words, more and more rooftop solar systems are being paired with battery storage?

A. Based on my understanding -- I don't have a solar system, but based on my understanding of this industry, yes, that's what's happening.

Q. And you also understand that the cost of these battery storage components of a solar system are -- the cost is going down for customers; would you agree with that?

A. I'm aware that battery storage costs were going down, but my understanding is that that trend has been upended here lately, yes.

Q. Now, the issue that you're talking about here in footnote 71 about rooftop solar's contribution during winter morning peaks, is that an issue with which a battery paired with solar storage could help address? In other words, that energy generated by the solar system during more sunny times could be stored in the battery and used during that winter peak; is that fair to say?

A. Yes. Yeah.

Q. Mr. Williamson, I'd like to speak with you briefly about a portion of your testimony on page 9.

A. (David Williamson) I'm there.

Q. You were quicker than myself. Hold on just a second.

And really, on pages 8 and 9, you provide some testimony concerning NC -- or NC WARN's concerns about Duke's NEM load forecast, right? I think we

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talked about that a minute ago?

A. Yes. I'm just highlighting that NC WARN brought up these issues in its initial comments.

Q. Okay. And on line 10 of page 9, you say, "NC WARN, et al., takes issue with the fact that the NEM load forecasts included in the proposed Carbon Plan is lower than the forecast that was provided in the Companies' 2020 IRP."

Did I read that correctly?

A. You did.

Q. Okay. And we did make that conclusion in our -- I think our comments maybe. I want to ask you this, Mr. Williamson.

Did you reach the same conclusion in your evaluation of Duke's forecast -- load forecast?

A. So in comparing the -- I guess the Grid Edge-related forecast in the Carbon Plan to the forecasts that were in the 2020 IRP, almost all of them are gonna be slightly different. I mean, you're gonna have some forecasts a little lower, some forecasts that are a little higher. I guess the big takeaway is what has the Company learned since that filing.

There are a number of things that have changed, there are a number of realities that the

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Company has had to incorporate in order to make sure that its planning process for this net load forecast -- so not just gross load, but net load forecast, is as accurate and as reasonable as it can be. I mean, understanding that it's not going to be perfect, but we can be realistic about these forecasts.

So yes, it will go up or down.

Q. Okay. And I appreciate that explanation. My question was maybe a little more narrow than that.

What I was asking specifically is that did you, or did the Public Staff, likewise conclude, like NC WARN, et al., that Duke's NEM load forecast in the proposed Carbon Plan is lower than the forecast that was provided in the Companies' 2020 IRP?

A. I can't, off the top of my head right now, remember if it was lower or higher. I do -- I will acknowledge that it is different.

Q. Okay. I have no more questions. Thank you.

CHAIR MITCHELL: All right. Is EJCAN present?

MR. QUINN: They are not.

CHAIR MITCHELL: Okay. All right. SACE, you're up.

MR. NEAL: Thank you, Chair Mitchell.

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CROSS EXAMINATION BY MR. NEAL:

Q. David Neal for SACE, et al. Good afternoon, Mr. Thomas. Starting at page 21 and continuing through 23 of your testimony, you critique the battery CT replacement step that Duke employed in its modeling; is that right?

A. (Jeff Thomas) Hold on. Let me get there.

(Witness peruses document.)

Yes. Yeah, that's generally analysis there of some of those results.

Q. And that page 21, lines 3 through 5, you ultimately conclude that the gas CTs that are forced into Duke's model to replace batteries and solar plus storage appear not to be necessary?

A. So what I do is I point out that they're very -- utilized very infrequently. Annual capacity factors of generally less than 1 percent until later model years, despite high winter reserve margins. But I note that most of this forced-in CT capacity is out.

Q. And you discussed projected decreases in gas burn with Mr. Quinn, so I won't go over that.

Later in that same section of your testimony at page 42, lines 10 through 12, you note that that reduced gas burn raises the issue of whether gas plants

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1 built prior to 2030 will become underutilized and
2 potentially stranded assets; is that right?
3 A. Yes. I think that raises the issue. And I
4 think, in a decarbonizing world, that's always an issue
5 that you have to consider.
6 Q. And you would agree the Public Staff has also
7 expressed concerns about gas supply; isn't that right?
8 A. Yes. Our SP5 baseline was no AP Gas with
9 limited Transco expansion.
10 Q. And even if Appalachian Gas becomes
11 available, I believe it's your testimony that it's not
12 clear whether there would be a firm pathway for DEC to
13 supply that under the SP5 portfolio to a gas CC in
14 DEC's territory? I think that's at page 46 of your
15 testimony.
16 A. (Witness peruses document.)
17 Thank you. Right. Yeah, we're talking here
18 about the shift in -- talking about a shift in SP5 from
19 both CCs being in each territory to having both of them
20 located in DEC's territory. And, obviously, that
21 creates challenges as MVP brings gas down. But like I
22 said, SP5 did not rely on Appalachian Gas.
23 Q. And you would agree, I think also at page 46,
24 lines 4 through 5, that as you just said -- well, no,

this is a little different.

SP5 delayed one gas CC to 2030?

A. Yes. There was a shift in territory and a delay in years.

Q. And nevertheless, the Public Staff is not recommending any change to the near-term procurement actions proposed by Duke with regard to 800 megawatts of new CTs and 1,200 megawatts of CCs; is that right?

A. So yes. One -- one CC was selected in 20- -- needed to be in service in 2029, and we experience that over a range, a range wide range of portfolios and sensitivities.

A. (Dustin Metz) And I'd like to give a little bit of context to the Commission. Sort of this has been a little bit of a moving target, that either 2020 or 2021 IRP, the Public Staff started raising a potential concern about firm deliverability of natural gas given limited pipeline capacity and whether or not we should be banking on that uncertainty for future combined cycles, and how to incorporate that, sort of a, what-if in a model.

Through -- as time has advanced since those filings, we've continued to see the potential -- or the actual delays of Mountain Valley Pipeline gas, and so

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there we continue to support that Dom Zone south gas pricing should not be included. However, what has transpired since the time of our either 2020 or 2021 comments, was Transco has announced and has filed with FERC, expansion projects from Virginia into North Carolina, station 165 down into -- I forget the other part. But it gets, I believe, into Iredell, subject to check.

But they're on Williams Transco's web page. Again, subject to check, that was approximately 400,000 or 400,063 dekatherms of new natural gas potentially coming into North Carolina. For those reasons, in conversation with Duke, we said, okay, there is now a -- at least a more clear pathway from our view of potential new natural gas supply that could be allocated to combined cycles for rough climates of scale that the 1,200-megawatt combined cycles are approximately 200,000 dekatherms demand.

So the approximately 400,000 dekatherms that we get from the William Transco expansion, if one would assume that one could get all of that capacity to either Duke utility, we thought that was reasonable to allow firm capacity to the combined cycles for modeling purposes. Again, when the Company comes in potential

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for a CPCN, those assumptions will be analyzed again as we continue to evaluate any changes and deliverability of natural gas to North Carolina.

Q. Mr. Williamson, turning to you.

Throughout your testimony, you criticized Duke for using a utility EE or energy efficiency savings target of 1 percent of eligible load in its carbon plan modeling; is that right?

A. (David Williamson) 1 percent of available load, yes.

Q. Would you agree that Duke labels that 1 percent of eligible load?

A. Yes.

Q. We're talking about the same thing; is that right?

A. Yes.

Q. And --

A. Just for clarification of the record, net of opt-outs.

Q. And as I understand it, you repeatedly call on Duke to instead stick with the utility energy efficiency savings potential from the most recent market potential study; is that right?

A. That's right.

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Q. And by that, you mean the market potential study, or MPS, that was prepared by Nexant and submitted with Duke along with its Carbon Plan application as Attachment 4; is that right?

A. So this market potential study was actually the same market potential study that was filed in the 2020 IRP, and it was accepted by the Commission for use in that hearing. And the reason we advocate -- the Public Staff advocates for the market potential study as the use is just because it doesn't necessarily provide a perfect projection, but it provides a realistic projection on customer adoption trends.

And that's pretty much the key point for a number of the Grid Edge technologies, is how are customer adoption trends changing from iteration of Carbon Plan and IRP to the next. And so the market potential study is going to take the realities of what's occurred in the -- since the last proceeding, and it's going to assume -- it's going to determine the economic, technical, and achievable potential that is available for Duke to use in its assumptions for whether or not there's a market for particular measures or there's a reason to continue offering certain measures.

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Q. Mr. Williamson, you would agree that that market potential study didn't take into account any of the carbon reduction requirements that are before the Commission today?

A. This market potential study was prepared -- like I said, it was filed in the 2020 IRP, so it was pretty much concluded back in 2019. So no, there was no law on carbon reduction.

Q. And isn't it true that the market potential study's projections are based on business-as-usual assumptions that were in place at the time the market potential study was conducted?

A. Can you clarify on "business-as-usual"?

Q. Sure. And I'd be happy -- I have a copy of that -- do you have a copy of the market potential study handy?

A. I do.

Q. And I'll say this is challenging, because the copy that Duke included doesn't have any page numbers in it, but I'll do my best to direct you.

A. I came to that same issue.

Q. So the PDF page 20, which is Section 2.2, methodology.

A. I do not have a PDF before me.

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Q. And again, I'm happy to walk this up if that would be appropriate.

(Pause.)

Q. So under the methodology section, there's text there. "A market potential study is therefore a discrete estimate of EE and DSM potential based on current market continues and savings opportunities." It continues, "An MPS does not contemplate potential changes in utility rates, changes in technology costs, nor changes in underlying economic conditions that provide a context for current consumption trends."

Do you see that?

A. After turning the page, I do see this.

Q. Okay. And so you would agree that that -- those current rates, current market conditions, those reflect business-as-usual assumptions at the time the market potential study is being conducted?

A. Sure. The market potential study, I mean, one of the reasons we support the use of it is because, as it just described, it uses current situation, current trends, and this market potential study is gonna get updated every two, three years, roughly. I think Duke's on a relatively -- a three-year path as far as updates.

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And, I mean, for purposes of whether or not program continuation should continue, it's an excellent tool for understanding where the market is and where it can go. What is realistic to the utility to continue to offer to customers.

Q. Or put another way, what was realistic for the utility to offer to customers in 2019 when the market potential study was created?

A. Well, similar to how EM&V is conducted, once an EM&V is concluded -- for EM&V on program evaluations -- once the EM&V is concluded, those savings and those levels of savings persist until the next model regardless of changes. Changes in savings will persist. The program may change based off of regulatory requirements or federal guideline changes, but those savings will persist just like the guidelines that are produced in this market potential study will persist until the next market potential study.

Q. And again, one of the issues that was lifted up that was a business-as-usual assumption were utility rates.

You would agree, all other things being equal, that changes or increases in utility rates send a price signal that can encourage customers to

participate more in energy efficiency than they did before the price increase?

A. Changes in electricity rates can play a factor into whether or not they participate in energy efficiency programs.

Q. And another one of the business-as-usual assumptions that was used for that market potential study was the use of the total resource cost test, or TRC. And again, that's -- there's tabs there that hopeful label page 12.

But do you agree that the TRC was the principal cost-effectiveness test used for that market potential study?

A. In 2019, the TRC was the traditional cost test that the utility used, so it's fair to say that that's the reasonable assessment that was used in 2019 to prepare this study. Now we have switched over to the UTC.

Q. So you -- so the Commission, you would agree, adopted the utility cost test, or UTC, as the predominant cost-effectiveness test in order -- issued on October 20, 2020, in the mechanism docket?

A. It was ordered on that date, but it didn't take effect until -- I believe it was this year.

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MR. NEAL: And, Chair Mitchell, if I could, just the Commission take judicial notice of its Order on October 20, 2020, in the mechanism Dockets E-2, Sub 931 and E-7, Sub 1032.

CHAIR MITCHELL: All right. We'll take judicial notice of that order. Mr. Neal, is there a -- what is the title of the order?

MR. NEAL: I think it's order adopting -- something along the lines of order adopting changes to the DSM/EE mechanism.

CHAIR MITCHELL: As long as the date is clear in the record, we'll take judicial notice.

Q. Turning your attention to page 82 of the market potential study, which again, there's, I think, a tab that's got a little arrow on it, about UTC, you agree that Nexant used a utility cost test sensitivity in its market potential study?

A. That appears to be what this section is about.

Q. And do you see where Nexant found that the results of that sensitivity, using the utility cost test instead of the TRC, indicate an increase of economic potential by 37 percent, and that's for the residential sector, 46 percent for the commercial

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sector, and 15 percent for the industrial sector in DEC; do you see that?

A. I see that.

Q. And that Nexant found that using the utility cost test instead of the TRC would indicate an increase of economic potential by 51 percent for residential, 51 percent for commercial, and 8 percent for the industrial sectors in DEP?

A. That's what it says. But, I mean, I guess the big thing is that we don't -- the market potential study and the forecasts that the market potential study is reflecting in that UEE forecast that we're recommending to be used, it's not -- it's not using the economic potential as its baselines. It's using the achievable potential, which is -- I can't remember the steps, but it's at least one, maybe two steps farther down in the pyramid.

Q. But -- so you don't -- nevertheless, it does indicate that using the utility cost test indicates an increase in achievable potential, whether it's economic or otherwise?

A. There are other factors that the technical and the achievable potential will take into consideration on whether or not customer adoption

trends will actually become achievable, so.

Q. And turning your attention to page 12 of the MPS, again without page numbers, the PDF page 12, they -- another business-as-usual assumption at the time that market potential study was conducted reflects current trends -- or the cumulative economic potential reflects current trends of declining avoided energy costs for utilities; do you see that?

A. I do see that highlight -- there are a lot of highlights on the page.

Q. I know. It's my copy.

A. Gotcha.

Q. Now, you don't anticipate that the trends of declining avoided energy costs will continue, do you?

A. So, like I was describing a little earlier with -- I believe it was CIGFUR's attorney, the avoided cost proceeding is what guides what avoided cost rates flow into the DSM/EE proceedings for cost-effectiveness. And so every -- every avoided cost proceeding is gonna introduce a new baseline of avoided costs. And so whether or not those avoided costs go up or go down is dependent on the avoid cost proceeding. So we could see increases or decreases.

Q. Well, again, the question I asked is, this

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MPS reflects current trends of declining avoided costs.

Do you anticipate a trend of declining avoided costs in the next few years?

A. So I can't speak on avoided -- on the avoided cost proceeding. My testimony doesn't cover the avoided cost proceeding. It -- yeah.

Q. If I could -- I don't need to mark this as an exhibit.

You testified in the most recent Duke Energy Progress DSM/EE rider docket; isn't that right?

A. I did.

Q. And that's Docket E-2, Sub 1294?

A. Yes.

Q. I'm just gonna hand you an excerpt from that testimony and ask you a question. All right. Turning your attention to page 11, there's a highlighted section in the middle. You see where it reads, "Finally, as avoided cost rates have decreased in recent years, cost-effectiveness has decreased." And then it continues. "The Public Staff does not anticipate this trend to continue. As fuel costs increase, more renewable capacity is added and coal plants are retired, the need for additional capacity resources grows, and the emphasis on great improvement

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1 increases. Each of these factors is likely to produce
2 higher valuations of the benefits from DSM/EE programs,
3 and increases the cost-effectiveness of both."
4 Do you see that?
5 A. I do see that.
6 Q. Okay. So again, the question was, you don't
7 anticipate that that trend of declining avoided costs
8 will continue in the near term, do you?
9 A. So until the next avoided cost proceeding is
10 concluded, I won't be able to answer that question.
11 Q. But again, it was your testimony in the most
12 recent DEP rider docket that the Public Staff does not
13 anticipate that trend to continue?
14 A. I mean, we can anticipate, based off of what
15 has happened, but we don't know for sure what will
16 happen.
17 MR. NEAL: Again, Chair Mitchell, I
18 would just that we take judicial notice of Public
19 Staff witness David Williamson's testimony from
20 August 24, 2022, in Docket E-2, Sub 1294.
21 CHAIR MITCHELL: All right. The
22 Commission will take judicial notice of the
23 testimony as indicated by Mr. Neal.
24 Q. Now, one other question about the market

potential study. You mentioned that there's different levels: economic, achievable, et cetera.

You would agree -- and again, I think this is summarized on page 12 of the market potential study -- it includes additional sensitivities; one is an enhanced scenario which looks at increased program spending over the base scenario, correct?

A. Yes. Increased spending via incentives is what it says.

Q. And the market potential study includes an avoided energy cost sensitivity, which is also built off of the base scenario but considers higher avoided costs, which we were just talking about, which may lead to increase in achievable potential, correct?

A. Well, our conversation earlier was on the economic potential, so are you referencing your economic potential conversation or achievable?

Q. Here, as I said, this is a section on the market potential study's achievable energy efficiency potential.

A. (Witness peruses document.)

Subject to check, yes, this is one of the scenarios that they used to evaluate.

Q. And you would agree that the following Tables

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1-2 and 1-3 show higher achievable program potential under both of those sensitivities, both the enhanced scenario and the avoided energy cost scenario, than the base scenario?

A. Where are you at again?

Q. The following -- I believe it's in the following pages, Tables 1-2 and 1-4, I think. I've given you my copy.

A. Yes. Where in the tables were you directing me? I'm sorry.

Q. I'm directing you to the -- how those tables reflect a higher achievable program potential under both the enhanced scenario, when compared to the base scenario, and under the avoided energy cost scenario, for each of the time periods in the market potential study.

A. When you talk about higher achievable potential, are you talking about the energy gigawatt hours or like --

Q. The percentage of savings, I think it's the last column.

A. Okay. Okay. Okay. There are a couple different columns, I didn't know what you were defining as the program potential column.

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(Witness peruses document.)

So based off of what I see here, as time goes on, the average annual percentage of base sales goes down.

Q. Again, turning your attention to the percentage, not over time but comparing the scenarios, comparing the enhanced scenario to the base scenario.

A. So an enhanced scenario is obviously going to provide a -- it's a more extreme scenario. So not really realistic to what we're dealing with here in the Carolinas. It could happen if certain things were to -- like, as the enhanced scenario described, if more incentives were to be offered or just increased program spending, you could -- you could achieve more savings. But again, that comes at a cost.

Like it says over here, increasing program spending via the incentives, you know, that's going to increase the rider, itself, regardless of the amount of savings that are achieved.

Q. As a general matter, Mr. Williamson, would you agree that models like the one used by Nexant for its market potential study are subject to more uncertainty the further out into the future they're looking?

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A. I mean, for the perspective of this -- and I would ask Mr. Thomas to help me out through another model of when you start assuming, you know, projections out that far in the future -- every model, as you get closer and closer towards the end of whatever planning horizon you are, you do have the potential to not necessarily have the same projections as you get -- as time moves on, your projections are going to update and change based off of what's really occurring. And so you potentially could have some level of forecast error the farther you go out across the horizon.

Q. And you refer in your testimony to Figures 7 and 8 from page 54 of the Public Staff's initial comments that were filed on July 15th.

Do you have those comments with you?

A. I have a select portion of it.

Q. Does it include page 54, by any chance?

A. (Jeff Thomas) I've got them here, I can pull them up.

A. (David Williamson) So I do have page 54, Figures 7 and 8 from our initial comments.

Q. And you would agree that Figures 7 and 8 were a way to compare the energy efficiency savings that could be achieved under three different scenarios; the

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achievable potential from the market potential study, which is in blue, labeled "Base UEE Sales"?

A. Uh-huh.

Q. And then second, 1 percent savings of eligible retail sales?

A. It says "available," but I think we agreed they're essentially the same.

Q. And that's, I believe, in red.

Then three, 1 percent saving of total retail sales in green?

A. Correct.

Q. So you would agree that, over the next few years, there's not a big divergence in those three different utility EE savings?

A. So on the early planning horizon, because of the amount of time it takes to actually incorporate change in how we facilitate programs, there's not gonna be a huge difference in the savings. But the big -- I guess the reason we incorporated these figures was to show the longer term, the 2030 and beyond, impacts that could be seen by the utility.

Because what that does is that incorporates a huge amount of error that, if that 1 percent of available sales as I've categorized it, or eligible

sales as they've characterized it, that's a potential where the -- if that 1 percent of eligible sales does not materialize, as far as the target that they're achieving, then that is -- that is kilowatt hours and megawatt hours and megawatts that the utility is going to have to find somewhere else. And it's gonna cause potential some reliability issues because it might sneak up on them. And then it might present a situation where they're gonna have less time to plan.

And so you might be in a situation where you would want to pick a resource, but you can't choose that resource, because you don't have enough time to get that resource out there by the certain time period, so you might have to select a different resource.

Q. Mr. Williamson, the question I was gonna ask is a little bit different.

When you, on page 23, line 18 of your testimony, expressed a concern about 1 percent of eligible sales going well beyond the market potential study, you weren't testifying about 2023, were you?

A. What page you were talking about?

Q. Page 23, line 18.

A. Okay. Sorry. What was your question?

Q. So you testified about a concern, about

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1 percent of eligible savings going well beyond the market potential study.

And my question is, you're not testifying there about 2023, are you?

A. I am talking about the planning horizon that the utility has used and how it -- for all of this net load contributors -- net load forecast contributes, so EE, electric vehicles, net energy metering, time-of-use customers, all of these components of Grid Edge are going to configure what becomes the net load forecast, which, in turn, feeds into what the model is going to be able to select as a resource on the supply side.

And so if we're not reasonably forecasting our baseline, where we're starting, then we're introducing potentially more forecast error in the long run.

Q. So to be clear, your testimony about being concerned about the 1 percent going well beyond the market potential study, those are the out years, that's not the next few years, just to be clear, correct?

A. It is the out years. But like we've heard from some of the Duke employees over the last two weeks of sitting in here, they are very hyper-focused on the realities of the system, where are we at, what are we

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having to deal with. And so it is very important to deal with this forecasting in not just the right now, but 2030, 2035, 2050, and start the planning process now.

Q. Mr. Williamson, you've heard -- I believe I've heard some of your colleagues generally agree with the check-and-adjust concept that Duke witnesses have referred to a number of times.

Is that generally correct, that you-all agree that the Carbon Plan has built into it a mechanism for checking and adjusting; isn't that right?

A. Yes. Similar to the IRP, it's a recurring proceeding to update forecasts and inputs and assumptions to gauge where we are and where we need to be and address any issues that have arisen with current policy or law.

Q. So in two years we'll be back here and we'll have a chance to evaluate how the Companies have done with trying to achieve 1 percent, or hopefully 1.5 percent of sales, and have a chance to check and adjust about how they're doing, what the trends are, in terms of reaching that goal or not, correct?

A. We will be back here in two years. Potentially my -- what I'm trying to get across is, if

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we don't set ourselves up for the most appropriate baseline in a forecast, then we are continuously adding on forecast error in the long term, like I was just saying, that we might have to address in a shorter amount of time period in the next few years, as opposed to acknowledging that we have an amount of megawatt hours that is -- realistically could happen, as opposed to setting a target to where we're going to hope that those savings are going to appear.

And when it comes to reliability and operating the grid, I don't think hope should be a plan. We should be -- we should be planning as realistically as possible.

Q. Mr. Williamson, in that response, when you talked about introducing error, you're basically saying anything that deviates from the market potential study that was prepared in 2019, before there was a Carbon Plan, before some of the other trends we've talked about that have changed the business-as-usual trajectory, when you say introducing error, you're saying just that it deviates from an almost three-year-old market potential study; isn't that right?

A. Well, every forecast, after it's finalized,

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is gonna have some level of error. As far -- as you go out, you're gonna see plus or minus more and more error. But what I'm getting at is that, by selecting a more -- the most appropriate forecast to keep as a guideline of where we realistically could see these savings, because the Carbon Plan is just taking in from these -- the Carbon Plan is taking in what's really occurring in the Companies' DSM/EE portfolio, and it's using this market potential study to project where -- knowing what we know, where could we be in the next 5, 10 years.

Q. Or again, as we've already been through knowing what we knew in 2019. I have no further questions.

CHAIR MITCHELL: All right. Tech Customers?

MR. SCHAUER: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MR. SCHAUER:

Q. Craig Schauer on behalf of the Tech Customers.

Mr. Thomas, starting with your testimony, on page 9 you mentioned that the Public Staff has a license for EnCompass; is that correct?

A. (Jeff Thomas) Yes, that's correct.

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Q. And the Public Staff downloaded the inputs and outputs that Duke provided to the intervenors; is that correct?

A. Yes. Yeah, when they were provided on the 19th, we did download those input files.

Q. All right. And then your testimony goes on to say that the import of the data failed; what did you mean by that?

A. So when you first load the EnCompass, the Excel input files, there's a master import file. You upload that file. That tells EnCompass where to find all the dataset and scenario settings to load in all the same scenario tree, as it's called, that Duke uses. And during that import process, errors were identified, which is unusual. And then sometimes errors you can bypass, but in this particular case, when I tried to bypass them, the import simply would not fail and I ended up with blank database and was unable to run any of the models.

Q. All right. And according to your testimony, the Public Staff has been working with Anchor Power Solutions about that issue?

A. Yeah. So we -- I communicated with them. And, obviously, all this was going on as we were trying

to write our testimony. So there was a bit of a crunch of time. By the time we went back and forth with APS, they -- I think they got back to me -- I want to say it was, like, the week before our testimony was filed, the week of our testimony was being filed. And they gave some identifications for how to correct this, and I was able to do this. This is actually a quote from EnCompass on the issue. But I was able to fix it and finally get it uploaded. But unfortunately none of the modeling or sensitivities that we've since done on SP5 have reflected in here. So we did have some challenges associated with that.

Q. When you said APS helped you correct this, what do you mean by correct "this"?

A. So Anchor Power Solutions, I reached out to them, I explained to them what's going on, the failure. That -- they provide really technical support. And then they looked at the errors I was seeing and helped me identify the problems. There was a dataset that had a duplicated line that was causing an error.

Then there was -- I don't remember the exact fix but they gave me like a four-step process to go through. I had to modify one of the input datasets. I had to change a couple things. They gave me a new

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dataset to upload that would help get rid of some of the errors. And then after I was able to get that done, I was finally able to load the dataset.

Q. All right. So I want to make sure I, kind of, paraphrase what you're saying.

Is it correct that the error that APS identified and helped you solve was not a user error on the Public Staff's part, but was because of the data provided by Duke?

A. I don't believe it was a user error. It was a new process. I've uploaded many datasets into EnCompass, and I've never had this happen before. I'm not sure what happened, but talking to EnCompass, I think they thought it might have been an expert error, but I don't know. I didn't have time to do a root cause analysis, unfortunately.

Q. Now, after consulting with APS and after having received corrected data from Duke or APS, has the Public Staff been able to completely replicate Duke's portfolio results?

A. So we ran the -- Duke's datasets, and I compared the output files that we received to the output files that Duke provided. As with P1 through P4, we were not able to exactly replicate the outputs.

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There's very, very slight deviations and differences in the resources selected, although that's very, very minor, particularly by 2035. I'm talking, like, 50-megawatt differences. And there's some differences in dispatch of the resources, like generation from different sources.

Some of that's to be expected by the way the outages are handled in EnCompass, right? Each unit has a forced outage rate. And to a certain extent, the outage timing is somewhat random, but they converge so that the outage rates are achieved in each -- you know, over the planning horizon. But you might have one unit go into forced outage in October, one in April, or something along those lines during the modeling process.

So I never expect it to exactly match. But since we were experimenting with P1 through P4, we've been struggling to exactly replicate, particularly the capacity expansion results from Duke. But like I said, we mostly got the same through 2040, so we found that that was, kind of, reasonable for use in our analysis.

Q. So you said some of the deviations were to be expected, and you explained why.

Were any of the deviations you found

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unexpected?

A. Just the capacity additions. I guess I was surprised that, given all the input files and everything, I expected that the capacity additions over time would be similar, or I mean identical. I know that sometimes running models, there's different processors, there's a lot of factors that go into the linear optimization, how it solves.

Duke has the server client, we have the desktop client. Our versions were the same. I stayed in the version that Duke had suggested. But regardless, I was seeing these slight deviations. And so that was just something we've experienced, and I think we mentioned this in our initial comments as well.

Q. I'd like to move to page 18 of your testimony.

On page 18, starting at line 11, do you recall that you discuss an analysis that Duke conducted which you call the loss-of-load expectation, or LOLE, and resource advocacy validation, also known as the LOLE validation step?

A. Yes.

Q. All right. And according to your testimony,

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in this step, Duke took the capacity expansion plans and ran them through the Companies' strategic energy risk valuation model, also known as SERVM, to ensure that the LOLE targets were maintained; is that right?

A. That's correct.

Q. All right. And later in your testimony, at page 24, you were asked about out-of-model steps taken by Duke, and you identified the LOLE validation step as an out-of-model step.

Why do you consider it to be an out-of-model step?

A. Because you're taking a -- it's not performed in EnCompass. I guess maybe I'll step back. Out of model is just out of the EnCompass model. You know, they do the capacity expansion in EnCompass, the production costing is in EnCompass, but then they take that resource selection and they run it through -- they take it out and they go convert it to the SERVM datasets, or they may have some scripts that help them with that. And they input that expansion plan into SERVM.

And SERVM may -- some may recall that this is the same model that was used in the resource adequacy study, the effective load carrying capability studies

that support the ELCC values for intermittent resources, the solar integration services charge study for integrating ancillaries -- integrating solar. This is not a new model.

So they feed this in there and then they -- this model is unique in that it doesn't have perfect foresight, unlike EnCompass within its optimization horizon. So this actually has uncertainty in load, it runs, I believe, thousands of times to estimate the effective -- the loss of load expectation for each portfolio to make sure it's within reasonable limits to achieve that one day -- per one outage per year, or 10 years, sorry.

Q. And you testified that -- on the same page that the LOE -- LOLE validation step using SERVM appears reasonable, correct?

A. Reasonable and consistent with the requirements of HB 951 regarding system reliability.

Q. All right and I noticed that you stated it appears reasonable. So did the Public Staff have access to SERVM?

A. No, we did not.

Q. All right. So the Public staff was not able to replicate or validate the LOLE validation step that

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Duke conducted, correct?

A. No, we didn't attempt to do that. I will say we -- I think we sent some discovery on that to confirm that -- essentially we've reviewed the Astrape model before, the SERVM model before, and we feel confident at least in its ability to calculate the LOLE. I've testified to that model before. So I didn't -- you know, I think it appears reasonable, because it appears a step to take the outputs from production costs, which is an hourly model, and feed into a much more granular model. I think the time steps in SERVM are 5 or 15 minutes. I forget exactly what it is, but it's much more granular. And so I thought that that was a reasonable step to make sure that these portfolios were still gonna meet the reliability requirements of 951.

Q. All right. And while you say it's a reasonable step, you can't opine on whether Duke's SERVM analysis accurately computed the LOLE values of Duke's portfolios or the intervenors' portfolios, can you?

A. I mean, without the model and training in that model, no, I can't confirm that they -- that the model outputs -- or the model was -- you know, I can only confirm that they use the SERVM model in the

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generally accepted way. And I think I -- in response to some discovery, I think they essentially explained that there's very little difference in how they modeled SERVM relative to historically how they've used it.

Q. Okay. Moving to page 50 of your testimony.

CHAIR MITCHELL: Mr. Thomas, make sure you're talking into your mike so we can get those -- you trail off a little bit.

THE WITNESS: Sorry about that.

CHAIR MITCHELL: I want to hear everything you're saying.

THE WITNESS: I'm sorry, could you repeat the page?

Q. Page 50, starting at line 8.

A. Okay. I'm there.

Q. So is it the Public Staff's position, just looking at your testimony on page 50, that if North Carolina law allowed the Commission to select PPAs as a resource for the Carbon Plan, then the selection of PPAs could allow Duke to achieve the carbon reduction requirements at a lower cost and with less risk?

A. I think that's what my testimony says. I think it could facilitate lower risk and lower cost,

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but obviously the devil's in the details when it comes to that. And whether or not they're legally permissible is an issue I think I've testified to at length today already.

Q. All right. And you note later, on page 50 of your testimony, that if Duke, itself -- I'm sorry, that Duke, itself, modeled importing onshore wind through PPAs in DEC's territory, correct?

A. Yes. I think there's multiple resources modeled as PPAs in the Carbon Plan. Some existing, and onshore wind was one of them.

Q. Right. But for onshore wind in DEC, you go on to testify that the Mountain Ridge Protection Act largely prohibits Duke from accessing higher wind resources in Western North Carolina; is that right?

A. I think generally therein -- yeah, I was summarizing Duke's Appendix J which discusses those challenges with siting wind.

Q. Right. But is it your belief that, due to the Mountain Ridge Protection Act, if DEC were to secure onshore wind generation, it would likely be necessary for DEC to import the onshore wind through a PPA?

A. I can't -- I can't speak precisely how much

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wind capacity could be available in DEC without importing. There may be some, but I can't speak to the exact numbers or costs there.

Q. Okay. Thank you. Moving to page 55.

Starting at line 7, you state that the resource costs used by Duke in the model are reasonable for planning purposes and based on reasonable assumptions; do you see that?

A. I do.

Q. All right. So the Public Staff's position is that Duke's assumptions for the capital expenditures for natural gas plants are reasonable; is that correct?

A. Generally, yes. I think they reflect, you know, particular for CTs, or similar to the CT cost that's used for avoided capacity and avoided costs, recognizing economies of scale and other savings relative to other publicly available data, so.

Q. So if I could just ask you to -- if I could revisit that answer. In your testimony, you said your conclusion that the costs were reasonable was based on the review of resource cost data that Duke used. And it sounds like you were giving me some examples of that.

Could you walk through what data you looked

at to determine that Duke's cost estimates were reasonable?

A. Sure. So, obviously, we look at the supply side data manual, which contains Duke's confidential estimates of capital costs. We do review NREL, you know, ATV, and EIA capital cost assumption data. I think PJM Cone as well. We do look at these and try to reference them. I think we do, to a certain extent, try to look at not only changes from past IRPs but also how the estimates from Duke kind of fit in in context to some of the more national or regional estimates that are used in, you know, say, EIAs estimates.

You know, and I think we also look at the source of those EIA estimates as well, you know, particularly digging into EIA's cost performance characteristics or capital resources are based on a 2020 study from Sargent & Lundy, and, you know, it's hard to kind of get a lot of the details there.

Whereas, when we look through Duke's estimates, I think a lot of their cost data is -- you know, we can look at what is the pipeline spur cost, what is the -- you know, there's a little more detail there that we're able to review.

Q. So is it correct to say that you looked at,

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kind of, two buckets of data; Duke's supply side data from its manual -- and I apologize if I didn't state that correctly -- and then publicly available benchmarks?

A. Yeah. I think to an extent we try to check that against as we can.

Q. So do you recall that, in the Gabel report, if you read it, on page 8, Gabel presents a chart that shows Duke capital cost estimates for CCs and CTs were lower than every benchmark that Gabel Associates found?

A. Yeah. I recall a lot of discussion about the cost of CCs and gas plants.

A. (Dustin Metz) And for context, I mean, for the Commission's benefit, the avoided cost docket went into great detail of the cost comparisons that both Duke Energy and Dominion did in comparison to the EIA published data and what adjustments that the utility found, and which we agreed with through detailed conversations.

Q. But focusing on the public benchmarks, I mean, is it the Public Staff's position that the cost estimates of all those sources that Gabel Associates found overstate the cost of construction -- constructing natural gas assets?

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A. (Jeff Thomas) I think that there's -- I mean, there's fundamental differences in the configuration and sizing, I think, that need to be taken into account that aren't always reflected in the publicly available data. And I think that that's part of it. And I think, ultimately, you know, comparing it to publicly available data is one thing, but Duke's -- Duke's estimates, which are largely derived from, I think, I believe Guidehouse, you know, they do these estimate for Duke, and that underlies a lot of these estimates as well.

In terms of reputability, I know Navigant, you know, and Guidehouse have been doing this for some time and do have knowledge specific to the North Carolina market and to how Duke would build these systems that I think is relevant to these proceedings.

Q. So one of the things you mentioned are configurations.

Are you sure that the configurations and the sources that Gabel Associates found are different that the configurations that Duke is siting for construction of the CCs and the CTs?

A. So it's been a while since I've reviewed this data. I'd have to -- I'd have to take a look at it

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again, but I recall that there's -- like, for example, the CTs, you know, Duke models this four-unit CT, I believe the EIA does a single unit. I just was looking through some of EIA supporting data earlier, but mostly for other resources --

A. (Dustin Metz) And for another example, we ran into avoided cost, when you look at the -- it may not be the most recent PJM Cone study, but it was at least 2020. When you go to reference to reference to about the third or fourth reference, you found what they were using for combustion turbine was not an F-frame, but it was actually advanced class. But you didn't find that out until you did expansive research.

So you can get what looks like -- it's like, oh, that's a peaking CT, but by the time you get to the research, you're like, oh, that's a peaking CT located in the northeast as the proxy which they had higher labor, land cost, and transmission expansion cost.

So I'm not saying anything negative towards the Gabel report, just based upon our past experience when we go to this published data, sometimes it's very challenging to find what they used, but another times it's enlightening what they use.

Q. And I just want to clarify that you've

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referenced EIA and a 2020 PJM report. You're not discussing the IEA, the NREL, or NREL, Lazar, or Brattle Group estimates that Gabel Associates cited?

A. (Jeff Thomas) So I don't think I said the 2020 PJM. 2020 Sargent & Lundy was a forecaster who underlies the EIA data. And we'd looked at the EIA data. I mean, we were looking at both gas and renewable costs that, you know, largely discern how recent price increases and changes to commodity prices were reflected in some of these publicly available estimates.

And, you know, so I think we are really kind of comparing those. I don't -- I'm not gonna sit here and say that we've reviewed every publicly available capital costs estimate for renewable resources that's out there, there's quite a few, but we have tried to look at some of the more reputable, I guess, government agencies and organizations.

Q. Right. And just to be clear, you were looking at a 2020 PJM report, whereas the Gabel report cited a 2022 PJM report?

A. I don't think I said the year of the PJM report. I thought we were looking at the more recent PJM Cone. But the 2020 Sargent & Lundy report, not

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PJM. That underlies the 2022 EIA AEO, the annual energy outlook capital costs that are referenced in the Gabel report.

A. (Dustin Metz) And for example, when you get further into the details, when you look at some of these more recent EIA data, they go back to 2019. So something like the more recent solar studies, they go -- still they're using 2019 benchmark functions for certain elements of the consideration.

Q. Thank you for clarifying that. Mr. Metz, I'd like to focus on your testimony for a few minutes.

Starting at page 24, you recommend that the Commission deny Duke's requests to begin near-term resource development activities for offshore wind; do you recall that?

A. Yes.

Q. All right. And you ask that Duke re-evaluate the need for offshore wind resources in the 2024 Carbon Plan; is that correct?

A. That's correct.

Q. Having reviewed Duke's rebuttal testimony, has the Public Staff's position changed regarding a denial of Duke's request to begin development activities for offshore wind?

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A. It has not changed.

Q. Moving a little earlier in your testimony, at page 13, you discuss early retirements of coal. I'll give you a second.

On line 16, you make the statement that Duke refuted the contention that early retirements could be achieved while still maintaining system reliability; do you recall that?

A. Yes.

Q. And in the footnotes, I believe you cite the Modeling Panel's testimony at pages 134 to 138?

A. Correct.

Q. Do you happen to have the Modeling Panel's testimony in front of you?

A. I do not have the direct testimony in front of me. You have it, Mr. Thomas? Mr. Thomas has it.

Q. If you could flip to the -- I believe 134 was the first page you cited from the Modeling Panel's testimony.

A. Okay.

Q. By all mean means, if you want to take a second to acquaint yourself with those pages, you're free to do so. I would suggest that we start on 136, which is where I believe it really gets into the issues

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you discussed. But please take a moment to acquaint yourself, because I want to ask you some questions on the testimony.

A. (Witness peruses document.)

Okay.

Q. So starting at page 136, at line 8, do you see the sentence that starts, "The assertion that the Companies' adjustments," and then it goes on?

A. Yes.

Q. Am I correct, just to paraphrase this for the record and the Commission, that Duke first talks about the necessary transmission timelines needed for retiring Marshall 1 and 2 and Mayo?

A. (Witness peruses document.)

Starting on line 12, for example, optimally timing the coal retirements to recognize the necessary transmission timelines is an appropriate consideration.

Q. Right. And so it's specifically in that section speaking of Marshall 1 and 2 and Mayo; is that correct?

A. That is my understanding of their testimony.

Q. Do you have Appendix P of the Carbon Plan in front of you?

A. I may. One second.

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Q. If not, I have an excerpt for you.
A. (Witness peruses document.)
Okay.
Q. If you could turn to page 15.
A. (Witness complies.)
Page 15?
Q. Right. Where it talks about transmission planning for enabling coal generation retirements.
A. Yes.
Q. Do you see the bullet points at the bottom of 15 that continue on to 16 discussing the coal units in DEC and DEP?
A. Yes.
Q. All right. If you need a minute to read that to answer my question, by all means do. I'm gonna pose a question to you and see if you can answer it without reading all of that. But by all means take the time if you do.
So to summarize what it says on all those various bullet points, it says that coal units, including Marshall and Mayo, would require significant transmission projects only if replacement generation is not sited at the location of these retiring coal units; is that accurate?

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A. Is not replaced efficiently at those locations, but yes.

Q. Do you recall that, in the Gabel report, on page 5, Gabel recommends that the Commission take advantage of the new generation being located at decommissioned coal sites to mitigate these transmission challenges?

A. Subject to check.

Q. Okay. Returning to the Modeling Panel testimony at page 136, line 19.

A. Page 119?

Q. Sorry, page 136, line 19.

A. Page 136, line 19.

Q. Duke's testimony states, quote, the Companies discuss in Appendix E the necessary adjustment to the Marshall 1 and 2 retirement dates endogenously identified by the capacity expansion model. To reliably retire Marshall 1 and 2 requires the completion of a transmission project to retire the units without replacement resources on site.

Do you see that?

A. Yes. I and believe Mr. Roberts had spoke to some of the logic -- the underlying logic on the 230 kV line explicit to the Marshall site.

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Q. Right. And Duke's statement was they had to adjust the retirement date of Marshall 1 and 2 in order to a accommodate a transmission project, correct?

A. That is my understanding.

Q. All right. Do you recall, on 27 and 28 of the Gabel report, that Gabel identifies the retirement date of the coal units in the preferred portfolio, and shows that the preferred portfolio retires Marshall 1 and 2 at the same time as the Duke portfolios?

A. Subject to check.

Q. All right. If that were the case, the preferred portfolio would allow time for the necessary transmission projects for Marshall 1 and 2, correct?

A. (Witness peruses document.)

I'm just trying to process the dates here.

Q. Sure.

A. To the extent that the Carbon Plan has already dates associated with the Marshall retirements as stated here and accounted for the transmission upgrades, then yes.

Q. Okay. Finally, if you can turn to page 137 of the Modeling Panel testimony, starting on line 8, and it goes really through the beginning of page 132. I'm not gonna read that into the record, but if you can

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take a second to read that, and I'm gonna ask you a question and see if I can paraphrase it correctly.

A. I would also ask Mr. Thomas to look over this over my shoulder, as it has some modeling implications as well. So can you repeat the pages again, please?

Q. 137 starting at line 8, through 138, line 2.

A. Okay.

(Witness peruses document.)

Okay.

Q. And here Duke talks about the challenges of advancing the retirement of Mayo from 2029 to 2027; is that right?

A. Starting at line 15, completing any transmission project by 2027 to enable the Mayo retirement continues to be an aggressive timeline.

Q. All right. And it closes by saying the challenges with transmission upgrades make an accelerated retirement ahead of 2029 significantly challenging; is that right?

A. That's my understanding, yes.

Q. Okay. And do you recall page 27 and 28 of the Gabel report, that Gabel shows that the preferred portfolio retires Mayo at the same time as Duke's portfolios, which is in 2029?

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A. Subject to check.

A. (Jeff Thomas) I don't know --

CHAIR MITCHELL: All right. I'm sorry, go ahead, Mr. Thomas.

THE WITNESS: I was just going to add, I know you're referencing the Gabel report, but this paragraph, in particular, is responding to Strategen, so I don't know if that's -- I just wanted to point that out. I believe this is -- we're talking about replacement battery resources at the Mayo site that Strategen is siting.

THE WITNESS: (Dustin Metz) I am getting a little bit cautious here if I'm testifying to the direct testimony of someone else here. I don't know what their underlying assumptions are. And we're picking dates and I'm not familiar with what you keep referencing back to the Gabel report. That's why I'm saying subject to check.

MS. LUHR: Yeah, I would add if you can provide -- if we can get them a copy of the Gabel report as we're asking questions about it, that would be helpful.

MR. SCHAUER: Sure.

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CHAIR MITCHELL: Let's do this. It's 5:00. We're gonna end. So bring the Gabel report tomorrow --

MR. SCHAUER: Yes. I have a copy. Yes, ma'am.

CHAIR MITCHELL: -- for this panel and you can resume. All right. With that, we'll be off the record. Go back on at 9:30 in the morning.

(The hearing was adjourned at 5:00 p.m. and set to reconvene at 9:30 a.m. on Friday, September 23, 2022.)

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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 27th day of September, 2022.

JOANN BUNZE, RPR
Notary Public #200707300112