PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Friday, September 23, 2022

TIME: 1:15 p.m. - 4:56 p.m.

DOCKET NO. E-100, SUB 179

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Kimberly W. Duffley

Commissioner Daniel. G. Clodfelter

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 23

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T A B L E   O F   C O N T E N T S

E X A M I N A T I O N S

E X H I B I T S

P R O C E E D I N G S

CHAIR MITCHELL: All right. Let's go back on the record, please, to continue with Commissioner Hughes. I'm sorry, Commissioner McKissick.

COMMISSIONER MCKISSICK: Just one or two quick questions.

EXAMINATION BY COMMISSIONER MCKISSICK:

Q. Mr. Williamson, this is addressed to you about the DSM/EE measures, you know, whether 1 percent or 1 and a half percent goals or target are reasonable. And I guess the question is simply this:

MR. BURNS: In the back Mr. McKissick, I hate to interrupt you. We can't really hear you, sir.

COMMISSIONER MCKISSICK: Oh, really?

MR. BURNS: Yes, sir.

COMMISSIONER McKISSICK: Is this a bit better now?

MS. GRUNDMANN: Yes sir.

MR. BURNS: Thank you.

Q. Yeah. And this is addressed to Mr. Williamson, and it kind of tags some of the issues Commissioner Hughes was asking about, and it's looking at that 1 percent, 1 and a half percent reduction in terms of a potential target. I mean what do you see as being objectionable about a plan to perhaps phase in that kind of production, say, over some period of time, some reasonable, measured period of time? And doing it in a way where it's -- you can verify the extent of the reduction, but with a target. Let's say you're looking at maybe six years, well hypothetically, you know, starting out at 1 percent, moving to 1 and a quarter, moving to 1 and a half, because I did notice in your testimony you say the Public Staff is open to consideration of incentivizing aspirational savings, targets in DSM and EE mechanisms. So maybe you can just give me your thoughts about that, if you could, sir.

A. (Mr. Williamson) Yes. So in the EE mechanism, we actually do have an additional incentive that came about -- I want to say that I might have a cite in my testimony to it, but it originated out of a South Carolina settlement during the time whenever they were trying to pull together a mechanism for their DSM/EE portfolios, and it was brought up to North Carolina to kind of create some alignment as far as what is offered. The Public Staff didn't take any issue with that type of target at that time. We saw it as more of a -- the mechanism in the EE Rider as far as the Senate

Bill 3 is designed to encourage energy efficiency, and we thought that that was a reasonable type of incentive to try and pursue a specified target and encourage the utility to try and hit it.

Now that we're a decade down the road, I know the majority of this -- all of this proceeding is on the first section of House Bill 951, but there is a piece in the second section of 951 that gets into the Multiyear Rate Case and how that proceeding is going to be handled. And we've already had plenty of conversations and rulings from the Commission on how to handle PIMS and other aspects of that Multiyear Rate Case. And now prior to -- prior to that language, we didn't have an establishment of -- prior year, retail sales target to -- for the Company or any utility to achieve by certain timelines, kind of similar to how we have swine, poultry, REC requirements and the REPS, REPS compliance as far as year timeline requirements.

But now that we have a system set up in the Multiyear Rate Plan, that could have something as far as a target or percentage of sales type achievement, goal or target, and that means it -- the Public Staff, I don't think, would -- we would -- we would believe that that would be the more appropriate forum for those types of discussions for us to look into how that performance could be evaluated across this whole Multiyear Rate Case and Carbon Plan reduction plan, planning. And, so, as far as in the mechanism, I know I do state that, but I also kind of caveated that this PIMS situation could be another alternative, and that might actually be another -- I guess more appropriate now that we actually have an established, you know, path for PIMS. That might actually be a more appropriate topic of consideration there.

Q. Okay. Well, that's what I was just curious about. I know you mentioned PIMS as a potential, but you also had the language there about, you know, consideration of incentivizing these aspirational savings with targets, so, I mean, I was just interested in getting further clarity from you in terms of what your thoughts are. I think you provided that in the interest of time since we have a lot going on this afternoon. Chair Mitchell, that's it.

CHAIR MITCHELL: All right. Commissioner Kemerait.

COMMISSIONER KEMERAIT: No questions.

CHAIR MITCHELL: Okay. I have a few for

y'all, and -- let's see. I'm going to start with the -- let's go back to natural gas supply issues.

EXAMINATION BY CHAIR MITCHELL:

Q. So let's start - sort of high level. Help me understand how gas gets into North Carolina and delivered to those power-generating stations? What happens from a transactional standpoint?

A. (Mr. Metz) So from my view, Duke Energy will need to secure transportation across the natural gas pipeline.

Q. And when you say "natural gas pipeline," you mean the interstate pipeline?

A. Correct.

Q. Okay.

A. And so let's say Williams Transco, they say all right, we want X amount of units off Williams Transco in terms of dekatherms, and then they have to say -- let's use Sutton as an example. They have to use Piedmont system, so that would be a transportation customer. So Duke will secure the right-of-way through Piedmont system, and the main Transco system for that unit of volume, subscribed unit of volume to that overall plant.

Q. Okay. And when you say "right-of-way," you're just using that figuratively. You mean they're going to secure rights to transport a specified volume across the LDC Piedmont, in this case is pipelines, intrastate pipeline system?

A. That is correct.

Q. Okay.

A. That's the issues when you have someone with electrical background trying to explain natural gas.

Q. Okay. Go ahead. Go ahead. And where does the actual gas -- where do the molecules come from?

A. The -- it's just based upon words injected. Predominantly, you have it down in the Louisiana area or off the Gulf, but then you also have the Marcellus Shale up in the northeast. I think you've heard another docket, sort of that pressure bubble. It's just an input to the system. I mean you can't trace that gas molecule from that point all the way to the other point.

Q. And that's fair, and my question wasn't very clear. But my real question was the gas is procured separately from the transportation -- from the right to transport that gas. Is that correct?

A. That's correct.

Q. Based on your understanding; recognize you're not the guy or girl that's having to enter into those transactions, but this is your understanding.

A. That is my understanding, that you procure the capacity, the pipeline, and then you also then procure the energy. In this case, it would be natural gas.

Q. And you just alluded to this, but at this point in time on the Transco Interstate Pipeline, which is the only interstate pipeline that serves North Carolina at this point, correct?

A. Correct.

Q. So at this point in time, molecules are entering the Transco pipeline from the Marcellus and Utica regions as well as from down in the Gulf of Mexico area, correct?

A. Correct.

Q. And maybe points elsewhere, but we'll just say for simplicity's sake --

A. Simplicity sake.

Q. -- those two regions. And so the Public Staff for some time now, in multiple dockets, has expressed concern about natural gas supply. Am I right about that?

A. That is correct.

Q. Okay.

A. And with both the electric and the gas filings.

Q. So let's focus, then, on the electric filings. In a nutshell, what is the concern that the Public Staff wants the Commission to be aware of?

A. The limitations of transportation or the ability to provide 365-day service to incremental or new natural gas facilities and scale to that of, say, a combined cycle.

Q. And does the Public Staff have concern, at present, about supply for the existing natural gas-fired generating fleet?

A. The existing fleet, no, I do not have a concern.

Q. Okay. Is it correct that certain of Duke's natural gas-fired assets are also -- are coal-fired, meaning they can be operated and generate electricity using other types of fuel?

A. Belews Creek, Marshall, and Cliffside are what they refer to as dual fuel operational. Yes, they can be coal-fired.

Q. And that would be with coal. So those facilities can operate on coal or on gas. Is that correct?

A. That is correct.

Q. Okay. And then there are backup fuel supplies at certain of Duke's natural gas-fired generating facilities as well, correct?

A. Correct. For example, Lincoln County CT units 1 through

16 and Lincoln County 17, they have on-site fuel-stored, backup fuel storage for those events that either economically or potential curtailments of the natural gas so they can switch over to fuel oil.

Q. Okay. So do the Public Staff's concerns about transportation of natural gas relate only to Duke's ability to get gas into North Carolina or do they relate to Duke's ability to get gas or to have transportation from a point inside North Carolina to its generating stations?

A. There's two points of concern. One is just the ability to get natural gas into North Carolina, which I think addresses your first question. However, the Public Staff has also addressed concerns of the natural gas price in relationship to the MVP potential delivery.

Q. Okay. I think that's a different issue.

A. Yes.

Q. But so am I understanding you to say the Public Staff isn't so much concerned about Duke's ability to transport gas within the State? It's just getting gas in on an interstate asset? That's the concern?

A. That is correct.

Q. Okay. We've talked some today about Transco expansion projects, and there's been muddled reference, I think, to what those specific projects are. And confirm that the Public Staff is aware of the expansion project that Transco has asked for -- asked for approval of, which it refers to as the Southside Reliability Project?

A. Yes. It is my understanding that there's two distinct projects. One runs almost horizontal from Virginia over into northeast North Carolina, and then the other upgrade is at Station 166 down.

Q. In Iredell?

A. Yes, ma'am.

Q. But it's possible that both of those projects make up the Southside Reliability Project for Transco's purposes of asking for approval from the federal government. Is that right?

A. That is correct.

Q. Okay.

A. And my review is that both of them have a common linkage, if you would, of the Station 166 upgrade, so they're both dependent upon that one center point on the system.

Q. Okay. And just -- help me understand so that I can think through this correctly. So let's say that Transco is successful in getting whatever approvals it needs and is able to put those new compressor stations

or whatever upgrades they are into the service. Essentially, what that does is that just creates more headroom or more capacity in its pipeline to transport more gas. Is that right?
A. Correct.
Q. And is that like 24/7 365 capacity or is it capacity only on certain days, times, months?
A. Those expansion projects should be 365.
Q. Okay. So just sort of it's -- in the lawyer's way of thinking, it almost just makes the pipeline bigger. Is that right?
Q. In a simplified way, yes.
Q. Okay. And so really, gas to the extent that that capacity in the pipeline comes available and somebody's able buy it from Transco, the gas could come from Marcellus and Utica or could come from the Gulf, right, given that Transco's now bi-directional?
A. In theory yes.
Q. Okay. Why only in theory?
A. Getting a little bit outside of my expertise and having to -- how Transco, sort of, has to maintain where your inputs are versus your outputs, and it's --
Q. Okay. Fair. Fair.
A. And that's in reference to the pressure bubble --

Q. I'll take your -- that's fair, and I'll take your responses in theory. That's fine. And, you know, I guess my question really is for you. The gas can be coming from either direction recognizing that Transco is a complicated universe in and of itself the way molecules are bought and sold and actually moved around on the pipeline.

A. That is correct.

Q. Okay. So the Company -- I want to make sure I understand. And Mr. Thomas, this is probably going to go to you, but either of y'all can answer it. I want to come away understanding as much as I can. The Company, in its modeling assumptions, we've talked a whole lot about this, and I hope y'all have Glen Snider's -- the Modeling Panel's testimony so we can look at that table, but the Company made some assumptions about its ability to get gas into the state, natural gas supply. Help me understand -- for purposes of its one -- Portfolio's 1, 2, 3, and 4. Can you-all help me understand exactly what those assumptions are?

A. (Mr. Thomas) Looking at the table in this, roughly it corresponds to our comments. I think -- you know, our comments laid out our recommendations, and then we had

subsequent discussion with Duke where modeling realities and other factors were taken into account to arrive at this kind of final table regarding the portfolio parameters, but --
Q. Okay. Hang on. Let me stop you there. When you say "our comments," do you mean July 15 comments?
A. Yes.
Q. So am I understanding you to say then that the -- comments the Public Staff made on July 15 were informed by subsequent discussion with Duke that went into the work you-all did for purposes of your later filings in this docket?
A. I would say that -- I guess what I was getting at was the comments we made on July 15th, made those comments, and then we sat down with you to hash out the details of how those comments would be implemented in their supplemental portfolios, and then that resulted in this table of --
Q. Okay.
A. -- SPA 1 --
Q. All right. I'm with you.
A. Okay. So essentially, we first -- we -- starting at the -- you know, pulled out hydrogen that was blended into the natural gas, which affected the price and the

emission rate, we stopped -- we did not allow CC --

Q. Hang on. Tell me about the Company's assumptions, the Company's assumptions in 1 through 4, and then we'll get to what y'all did for 5 and 6, but 1 through 4.

A. Sure. So yeah. So in the 1 through 4, their base case was a limited Appalachian fuel supply case, so they had -- the existing CC fuel fleet was fueled in part by App. Gas, and had firm transportation for two new CCs, and then they did not have those CCs on backup fuel.

Q. So do I understand correctly that those assumptions are really predicated on the development of MVP or the MVP Southgate asset and being able to procure capacity from those assets, one or both of those assets, to get gas into the state?

A. I believe so. Mr. Metz may expand, but I don't know if the actual molecules would come from that MVP line. But the pricing contracts that were worked out, would that allow them access to that price? I don't know if the molecules would necessarily come directly from there, but...

Q. Okay. All right. Well, I'll just -- Mr. Metz, anything?

A. (Mr. Metz) So -- I'm trying to keep this simplified so --

Q. So I can understand it?
A. No, so I can do better in explaining it. That if MVP comes in at where it's proposed in Virginia --
Q. Uh-huh (yes).
A. -- you're still limited by the existing Transco system. The pipeline is the pipeline. MVP Southgate, which we treat as a separate project, would bring further capacity in a different part of the overall Transco system, in my words, potentially overcoming in part maybe that bottleneck that's occurring, in my words, at Station 166. So there would still be a limitation of the main Transco line, but that would at least enable the energy element, the commodity price, to be brought in at that price. So if MVP came in where it's directly located, I believe there would still be a limitation on the main Transco price, on the main Transco line.
Q. What do you mean "a limitation on the" -- so -- okay. Let me ask it this way. So if MVP comes in, and there's still a limitation on the Transco line, main line, it doesn't change things for Duke, right? I mean it doesn't ameliorate the situation for Duke, right?
A. Unless Duke had contracts and they could potentially maybe do something -- I'm going way far outside of my

understanding, but there may be something where they're procuring contracts to and from. They were talking about you can bring an energy element in from one place to the other.

Q. Okay. So that gets fairly complicated fairly quickly. So just for purposes of my limited understanding or ability to understand, so even if MVP were developed and MVP Southgate were not, that might free up some pipe -- interstate pipeline capacity that could ameliorate the situation or improve, make more capacity available for Duke to utilize for purposes of supplying its power-generating station?

A. That is my understanding.

Q. Okay. So Mr. Thomas, keep going.

A. (Mr. Thomas) Sure. And then in Duke's original portfolios, they've modeled a no Appalachian Fuel supply case. And so in this case, they fueled their existing CC fleet from Transco's Zone 4 pricing, and then they estimated that they would not have incremental firm transport for new CCs. So these new CCs were still pulling natural gas, but then they modeled them during certain times of the year running on ultra low sulfur diesel as an approximation of, you know, we don't have firm transport, so we can't burn at this moment in time.

Q. Okay. Can you comment on the reasonableness of that assumption?

A. On the --

Q. Reasonableness of the assumption that the gas-fired assets would have to run on ultra low sulfur diesel at some months of the year.

A. I think in the model, they have it running on that backup for extended periods of time. I think in certain parts -- it's a lot of low sulfur diesel. You'd have to truck in to run these CCs at full-bore, so I don't think that Dustin -- Mr. Metz may have more to share, but I don't believe that that's historically been the practice to run CCs on diesel fuel.

Q. So do I understand then the case to be that the modeling was assuming that these gas assets would be running -- when you say full-bore, you mean on a full-time basis on the ultra low sulfur diesel as opposed to on a few hours here and there like some of the Duke's gas assets -- natural gas assets might have to do when they're relying on backup fuel, for example? Just trying to understand.

A. Yes, something to check out. I'd have to revisit the modeling constraints that were included, but I think it may have been -- I know that they have fuel supply constraints, and so there may have been -- the backup fuel would be switched too, and that supply is constrained.

Q. Okay.

A. I'd have to revisit the modeling, so that's subject to check, but I think that's generally how it would approach.

Q. Okay. So when I ask Mr. Snider this question, he might be able to say what constraints that were utilized in the model to limit the time that these units were running on.

A. Yes. I think that panel could speak some more detail about the specific constraints that were used there.

Q. Okay.

A. (Mr. Metz) And the target is the month, going off memory is the month of January in question.

Q. And that's clear in the testimony. Just trying to understand the very specifics there. Now, help me understand. And, you know, you-all discussed this in the July 15th comments, and then in the Exhibit 1 to Mr. -- to the Modeling Panel's direct testimony, there's discussion of this, but I'm still not entirely clear on the reference to existing CC fleet fuel

Transco 4. It's Transco Zone 4. Help me understand specifically what that means when we're referencing Transco Zone -- I know what Transco Zone 4 is, but what is the reference to Transco Zone 4 there mean for Duke's operations?

A. So from a modeling standpoint, the model has different fuel prices for different zones. So let's say it has zone 3, zone 4, zone 5, it's just the model says you want natural gas? Where can you get it from? For pricing, you're going to use zone 4 pricing. That's what that is referencing.

Q. And so when we say we want zone 4 gas, do we mean actual gas or do we mean transportation? What do we --

A. That is referencing the zone 4 natural price, natural gas price.

Q. So the commodity price?

A. For the commodity, yes.

Q. And then also, we talk about zone 5 price volatility. Do I understand that correctly to mean that there's more price volatility in zone 5 with respect to the commodity than there is in zone 4?

A. Yes.

Q. Okay.

A. (Mr. Thomas) Although, you know, within the model, I just point out that the volatility is -- you know, other than intervenors put this as not entirely captured. There is seasonal, monthly volatility. The price changes monthly but not as volatile as the actual market where you have daily, hourly fluctuations.

Q. Okay. Thank you for pointing that out. So why is it appropriate to assume zone 4 pricing as opposed to zone 5 pricing? Make that -- connect those dots for me.

A. (Mr. Metz) So this is a little bit of an evolving story, and I'll look over to Mr. Thomas too. So in our initial observation was for -- in preparation of our comments, walking back in time that says, okay, we looked at your model, and what natural gas price was being used for those resources. We had an observation or concern that says zone 4 -- just using zone 4 for new combined cycles may not be representative of the actual energy price that you would actually be cured in realtime. You would probably be picking up something out -- it'll be an average of all of Duke's natural gas contracts just in realtime. This is a mismatch between how we run the system in operations, in realtime, versus what we're doing for modeling simplicity.

Q. Okay.

A. So our initial observation says look, zone 4 may be too low. That's why we want to use an average of zone 4 zone 5 at least to pick up that -- knowingly that you probably can't just get zone 4 pricing.

Q. Okay. So I'll stop you there. So is it possibly the case that Duke enters into contracts for gas and is able negotiate a price, and is it the feeling that using the zone 4 -- or is it the Public Staff's opinion that using zone 4 and zone 5 combined or averaged, as you-guys have done, is likely to approximate what Duke's actually going to have better approximate what Duke's going to have to pay for the gas?

A. Yes. That was our attempt to address that concern, understanding that it's not perfect and it doesn't address the intraday volatility.

Q. Okay. One thing that's kind of confused me is this no Appalachian Gas, no Appalachian fuel supply case. What we're really saying is not necessarily no Appalachian Gas, but rather no MVP or -- no MVP plus MVP Southgate, right?

A. (Mr. Thomas) Yes. Yeah.

Q. We're just using Appalachian as just a way to -- okay.

A. And I think before it was MVP Southgate, I think 2018, IRP we were talking about ACP and --

Q. Understood.

A. And stuff like that, so...

Q. Understood. Okay.

A. For a commodity price, I mean, it was coming at a lower price than compared to the zone 4 or zone 5 pricing. So if it comes in at a lower price and you direct assign that to any new natural gas generation unit, it's going to have a low unit cost for serving that given hour. So that was our conversation to ensure that we weren't putting too low of a price on looking out into the future, and it would essentially not force, but it would direct behavior to go ahead and pull in that resource.

Q. Okay. So even if -- that makes sense to me. Thank you, Mr. Metz. So -- but even if the -- let's say the MVP remains uncertain and just kind of continues in the litigation churn that it's in now, and that means MVP Southgate remains uncertain as well. Let's say Transco goes forward with its Southside Reliability Project and Duke's able to somehow take advantage of whatever capacity that creates in Transco and to North Carolina, isn't it likely that they would procure Appalachian Gas? I mean, wouldn't they be able to go out and buy that gas at that price since they can now get it into the State? Does my question make sense? And you can say no if it doesn't.

A. No. It makes sense. I'm getting a little bit out in front of my skis (sic) here on this particular topic.

Q. Okay.

A. So that's why I'm being cautious of what information I provide.

MR. JOSEY: Chair Mitchell, if you would like us to or the Commission would like us to provide a late-filed exhibit from our natural gas section or offer up a natural gas witness, maybe next week, we could --

CHAIR MITCHELL: I mean, I'm curious about -- I understand, Mr. Metz. I know who these guys are and their backgrounds. And when he tells me he's out over his skis, I accept that, and that's fine. I'm just wanting to understand sort of the -- and you tell me when you're in the territory you're not comfortable in, and that's okay. I'm just trying to understand what you-all learned and were able to learn about these assumptions that they were using in their models.

A. So from my understanding is, remember we talked about Station 166. I don't see a project north of 166. So remember we talked about your example, sort of get a bigger pipeline, we get more gas now, right? If I never increase the pipeline north of 166 going up to the -- um, Dom Zone south gas, I can never get that price down. The only thing that I've freed up was from the upgrade down and the amount that is in that zone.

Q. Okay. I follow you now, and that makes sense. And I'm going to ask these same questions Mr. Snider, so we'll hear what he says or whomever on the Modeling Panel is in a position to answer, so I appreciate your entertaining my questions and answering them. All right. Mr. Thomas, back to you. So then the changes you asked Duke to make in the natural gas supply assumptions for purposes of the additional -- the modeling you-all asked them to do, explain those to me.

A. (Mr. Thomas) So I think just that, at a high level, we -- it resulted in a higher delivered price of gas to the fleet, both new and existing, and then there were constraints placed on the amount of existing gas that was allowed to come in. And then the backup fuel for CTs and CCs was slightly modified, and then also we wanted to let the model to select between J-Class and F-Class, the 800 or the 1200 and 800-megawatt CC, so that's generally the high level of the changes that we pushed for on the gas side.

Q. On the gas side, right?

A. Yes.

Q. And I know there were other changes as well, but I'm just focusing now on the gas side. Okay. And at one point in your testimony -- you were testifying to someone, I don't remember who, but you said -- there were sort of artificial constraints versus physical constraints in the model that you can make, and I think -- this is how I understood your testimony, so I want to make sure I'm right. An artificial constraint would be telling the model you can't select any CCs. Is that what you were talking about?
A. Yeah. In the absence of a state-wide ban on combined cycles, that would be artificial. It wouldn't really reflect the reality.
Q. Got it. It's just something you're imposing on the model for an arbitrary --
A. Yes.
Q. Okay. And then a physical constraint would be no new gas coming into the system?
A. Yes. So that physical constraint in EnCompass, you might put a limit on the daily imports of gas to reflect the actual constraints you expect, and that may lead to a CC not being selected, but that's up to the model, then, to decide whether it's worth to build an underutilized CC or not, right? So that's -- I think

that's kind of the blink.

Q. And so I understood your testimony to be and I understand from a -- at least I think I understand, from what's in the record now, that you-all never went -- you-all and Duke, the Public Staff and Duke, when discussing additional modeling work, never went so far as to say no new gas into the system? Is that right?

A. No. I don't believe we ran that type of sensitivity to say no incremental new gas.

Q. No incremental new gas. And so I'm going to ask you to speculate, and I know that you're going to -- I'm sort of anticipating your answer, but what happens if you tell it no new gas?

A. So I think more than likely, what's going to happen there is it would definitely, more than likely, not select the combined cycles. The CTs,it might still be able to select that because it could get -- you know, a CT might be able to run when -- and utilize other gas that's not being burned on the system or run on backup fuel, but the more -- the tighter you make the gas market, the less likely it would be to build a CC because you have a lot of capacity, and that certainly would contribute to the reserve margin requirements.

But you wouldn't be able to actually generate during peak, so it would disincentivize the model to select that excessive expenditures.

Q. And in Supplemental Portfolio 5, there are two CCs selected. Is that correct?

A. Yes.

Q. Even with the constraints on gas supply, the model still selects two of the CCs. Okay.

A. Yeah. You know, and also, I think, you know, part of the choice of the model, right, so we've identified other issues like the optimization period. It doesn't know what's happening beyond a certain time.

Q. Yeah.

A. And also just the general decline in gas consumption over time due to the introduction of new renewables, those capacity factors are dropping, so, you know there's maybe in the very beginning when it's built, it's not able to run fully or it's maxing out that gas supply. But over time as these CCs are utilized less, you know, that creates additional headroom on the system.

Q. Okay. The Carbon Plan -- do y'all have the Carbon Plan in front of you? And I'm going to ask Mr. Snider about this too, so just do your best to answer. I know this is not the Public Staff's document. In the appendix, in the fuel supply section, I'm looking at page 7. That first paragraph, it's the first full paragraph on the page, and I'll paraphrase it. That the Company's CC fleet is deficient of interstate pipeline firm transportation capacity due to cancellation of ACP. Do y'all see that?

A. (Mr. Metz) [Nods in the affirmative].

Q. And that point is made elsewhere. I think Mr. Snider of the Modeling Panel make it in their direct testimony as well. So as we transition, as the Companies continue to undergo this transition away from certain types of generating facilities to other types of generating facilities, and facilities are retired, and I'm mindful of Mr. Holeman's testimony where he says we need to replace before we retire, but just thinking about the reliability of the system, does this -- address the concern that I have when I read, "The Company's combined cycle fleet is currently deficient of interstate firm pipeline capacity." I mean, that's the existing fleet. How do we -- should I be concerned about reliability when I read that? Because earlier when I asked you if y'all were concerned about the existing fleet, you said no, and you were fairly confident, which made me feel better, but what about the fact that this is in the Carbon Plan?

A. (Mr. Metz) I did not -- in full transparency, I did not pick up on them saying deficient. To state more plainly, that's news to me that our current combined cycle fleet is deficient.

Q. And again, it appears in Mr. Snider's testimony, and we'll give the Modeling Panel our -- it appears in the Modeling Panel's testimony. Poor Mr. Snider. I keep calling him out, but --

A. (Mr. Thomas) The only thing I would just add to that, I do think that this is taking into account, you know, if they were to run all their CCs at full tilt, including their DFO plants running on the maximum amount of natural gas, and they do kind of discuss how they do have coal for, you know, Belews Creek. Currently, they have coal for Belews Creek and Marshall, so that may be a factor as well, but certainly, I think that it could be a concern in terms of keeping the lights on.

Q. Okay. Well, we'll let the Modeling Panel speak to the specifics or the details underlying that, of this paragraph in Appendix N. But the Public Staff, I haven't heard the Public Staff say at any point or haven't read testimony or read comments or heard you-all providing testimony, since you've been on the stand, that you don't believe that natural gas isn't going to play an important role in this transition for the coming years. Is that correct? Do you want me to say that question again because I said I used --

A. Yeah, please.

Q. The Public Staff believes that the natural gas has an important role to play to manage the reliability of the system as the Company moves away from or retires certain types of generation and brings on additional types of generation. Do I understand your position correctly?

A. Yeah. And I think I testified earlier about how, you know, it does appear to be serving a transitional bridge, a role in the absence of, you know, non-energy limited, firm dispatchable for resources available now they are carbon free. It does appear to be serving that role and could be important to maintaining system reliability.

A. (Mr. Metz) I concur.

Q. And you said "could be important" to maintain system reliability. Can you speak a little bit to that because I don't know if you heard the Reliability Panel's testimony a couple of days ago, but speak to the role that these assets will play with respect to reliability.

A. So not speaking for Mr. Thomas but I think when we say "could be," I mean, we are looking at this until 2050. I mean, we're looking at this over the long-term. When we say "could be," our expectation is that as technology evolves and Duke can implement it in its system, yes, we may not be as dependent upon CTs as we currently are, I mean, because that's a function. Just because we don't have -- using battery storage is ample as it is. We don't have a large penetration of battery storage in our system. So as we're looking ahead, we expect that the operation standpoint to potentially shift to say okay, well, yes, we have -- we currently have this set of tools, I believe as Mr. Holeman was testifying, in the future, we are going to have a different set of tools, and we're going to continue to evaluate and readjust as we move forward in time.

A. (Mr. Thomas) And I guess if I can add on to -- the reason I say "could be" was natural gas is not the only thing that can provide firm dispatchable resources. If there was a federal ban on new natural gas pipelines, if no new gas came into North Carolina -- well, natural gas may not be an option. New natural gas may not even be a physical option anymore, in which case you may need to then start potentially delaying coal retirements to maintain the Voltage Support Ancillary Services that are required. You may need to invest in significantly larger quantities of solar and solar plus storage and wind that are envisioned in the Carbon Plan in the absence of natural gas capacity.

I mean, it's possible. There are batteries and solar and intermittent resources combined can provide system reliability if it's properly, overly built and there's sufficient energy that's being able to charge those batteries to provide that, but that's very expensive as well. That can be very expensive. And as the Reliability Panel testified to, there's not a lot of experience in the system operations room in managing that type of fleet, So I think could be is just kind of looking out at the uncertainty of what we have coming in.

If MVP and MVP Southgate collapse and there's this permitting reform bill, is unsuccessful, and they are never built or never completed, that could force North Carolina to start looking at other different options that in the absence of the ability to build new gas plants, particularly

the combined cycles that have been identified in almost every portfolio that we've looked at in the near term.
Q. Okay. Commissioner Clodfelter asked a couple of questions, I think he asked to the Modeling Panel, but he could have asked to one of the other panels, about the Belews Creek 1 and 2 that are currently firing at 50 percent natural gas. Is that yall's understanding that they're firing at 50 percent?
A. (Mr. Metz) They have up to 50 percent. I'm looking over to my left. I believe it is non-firm for Belews Creek, up to 50 percent on each unit, non-firm.
Q. And Commissioner Clodfelter, you can tell me if I'm getting this wrong, but I think he asked had we looked at taking those to 100 percent or closer to 100 percent, and he received an answer to that. But do you-all have any thoughts or do you have any -- can you provide us any response to that question?
A. I'm thinking. Just for context of the conversion, there's a few elements to consider, and more than just a few, but you have to get the fuel supply there, so you have to look at the natural gas pipeline. I mean --
Q. Back to the pipeline issue too?
A. Back to the pipeline issue and whether or not you can actually get that 365 service per that quantity. So if

I would look at it and say okay, well, Belews Creek is a larger unit site in terms of megawatts, so if I want 100 percent, it means I need more through-put or more gas coming off the system. Then if I want it firm 365, then that's another evaluation. To go further into the mechanics of the overall system, then you need to look at it and say, all right, now if I am going to burn 100 percent natural gas, instead of 50 percent, you have to start considering it multiple other elements and whether -- how the internals of the system can actually handle that, handle the temperatures, handle the pressure, and go through every part of the plant all the way up to the turbine and see if it can handle those changes.

I have not performed that analysis. I don't even know if I'm qualified to go through that entire coal plant to see if we can do that change.

Q. Okay. And so what I'm hearing you say is we shouldn't assume just because it's been converted to burn a certain percentage of natural gas, that it could go beyond that cost effectively and practically. Is that what I'm hearing you say?

A. That is correct. And again, take that a step further to say well, for a coal plant that was converted, it does not have the same efficiencies or references heat break as compared to a combined cycle, so you have to start taking -- and that's so if I have rounding numbers. If I have a 30 percent less efficient combined cycle or a coal plant converted over to DFO, it's going to be very expensive over the long-term. It may be more cost-effective in a perfect world to go with the other scenario and leave it alone.

Q. Okay. Do you know anything about -- do you-all know anything about Duke's decision to take those two units only to 50 percent? I mean, could that -- could that decision have been informed by this type of analysis that you're describing should be done?

A. It was my understanding that -- because we reviewed this during the general rate case, it was my understanding that this was a balance of fuel supply and the cost to get firm 365 service. To go up to 50 percent was a cost balance of saying we're going to go non-firm and only go up to 50 percent.

Q. Okay. When you were talking about firm and non-firm, we're talking about Transco capacity again. Is that right?

A. Correct.

Q. Okay. Just making sure because, you know, we talked about -- we talk about different types of service from the LDC to these plants, and so when we're having these conversations, I want to make sure we're clear on are we talking about Transco capacity, are we talking about interruptible service from the LDC?
A. There is also a function of LDC if they tap into the LDC because the LDC is responsible for its pipeline pressure. So if you look at where you connect a high demand on a certain pipe, if you pull up too much, you could have a pressure change, and that would require the LDC to beef up or upbuild its system, then you also have to compare that cost and see whether it's worth it or not.
Q. Okay. That's helpful, and again, I know that I've asked you to sort of go over your skis again. All right. Mr. Thomas, you've provided pretty extensive testimony at this point, so I'm not going to belabor this much more than I have to, but you've provided extensive testimony about the experience with EnCompass that the Public Staff had this time, and we've heard from some of the intervening parties about their experience with EnCompass. Is there anything that the Commission should do to try to head off or address the issues the Public

Staff had with in utilizing EnCompass?

A. (Mr. Thomas) So yeah. I think there are some things. I think -- and, you know, in full, you know, transparency, I think a lot of some of the issues may have arised simply because of the compressed timeframe that Duke had to perform all this modeling with EnCompass and share this data in a way that is not really precedented in terms of sharing modeling inputs like they have.

So I don't want to say that this was something that necessarily won't be addressed by Duke, and I hope that they will. But yeah, I think that there's steps such as, you know, I spoke earlier about calculations of conversion of capital costs into model inputs and taking model outputs and converting them to to, you know, present value of revenue requirements. There's worksheets and documentations they've done kind of for some of the interim steps that I think would be helpful. I'd like to see those potentially in future Carbon Plans provided contemporaneously with the EnCompass inputs. And I applaud Duke for providing all those inputs right away, but obviously, the challenges that everyone ran into immediately set us back some time.

Q. Okay.
A. And I think this is hopefully something that the Commission can address or Duke can address but, you know, taking Duke's -- once Duke exports its status as before they upload into EnCompass, into the data site to share with intervenors, I think it'll be helpful for them to take it and import it into a fresh database and just validate that. You know, they don't have to rerun every model, but rerun a few models and just validate that they're getting the same results so that we don't have these same export/import issues that we were kind of experiencing.
Q. Okay. The additional EnCompass question for you, the dynamic dispatch issue. And we've heard about the fixed dispatch for the solar plus storage, and then you-all asked them to take that -- to convert to or change to the dynamic dispatch.
A. Uh-huh (yes).
Q. And we've heard from Duke about the sort of practical implication of that, was it made the model spin for 36 hours as opposed to just a few hours. And so do you envision the -- and I talked about this some with the Modeling Panel, but is that -- will that improve with time as the model gets more sophisticated?

A. That's a good question.
Q. The practical limitations of the model.
A. Yeah.
Q. Will they improve with time as the model gets more sophisticated?
A. That's a good question. I don't know for sure. Now I know computer hardware is always getting more advanced, and so it's possible that changes to the servers that Duke's running on with the computers, that intervenors are running on, could help increase -- you know, decrease model run times. There could be optimizations within the EnCompass code. That's the linear optimization algorithm that could provide, you know, decreases in model run times. You know, EnCompass Anchor Power Solutions has a team of software engineers that I'm sure they're always looking to optimize these things.
And then in addition, there's other -- you know, there's other discussions with them, with Anchor Power Solutions on what might be done, even just modeling decisions that could help improve the time. You know, I think the solar -- the dynamic dispatch of solar plus storage was very impactful. Maybe there's another way that we can kind of approach

this in the future, but I think that that's very important. And there may be tradeoffs where perhaps fewer tranches of, you know, renewable resources -- you know, right now, they have multiple tranches associated with different levels of interconnection costs, all of those different resources. So there's like six different stand-alone solar resources in both DEC and DEP.

You know, getting rid of that or narrowing that down, that, in and of itself, can reduce run time, and then you can kind of trade off and use the more computationally expensive dynamic dispatch while you're making, trimming other areas that may be a little less material. And then obviously, you know, if the Companies merged or combined, now the number of resources that you are modeling are literally cut in half because you no longer have a DEC and a DEP. It's just a Duke. And so I think that there's obviously benefits there, but we share our position on other benefits of a merger as well.

Q. Okay. I'm going to ask you-all some questions about the red zone. Were you-all able to hear the testimony provided by Mr. Roberts and Ms. Farver, the Transmission Panel, several days ago?

A. (Mr. Metz) Yes.
Q. Okay. I understood their testimony to be that costs associated with certain of the red zone expansion projects were included in the modeling work. Is that your understanding as well?
A. (Mr. Thomas) My understanding of this, and, you know, that Duke used a generic network upgrade cost for new solar, and that was -- I mean, it was generic, but it was based on historically looking back at interconnection studies. And when you look at the total investment related in network upgrades associated with solar, that the model selected it, it approximately was equal, I think, to the Red Zone Plan in dollar amount, but I don't know that the red zone upgrades were -- they weren't added in or forced in. I think it was --
Q. Okay.
A. That was my understanding with conversations with the Duke team, but...
Q. So is it then your understanding -- let me make sure I understand your understanding. That the transmission adder that Duke used reflects the cost of those red zone projects or some of them?
A. (Mr. Metz) So yeah. The foundation of this was the studies coming out of the Transition Cluster Study. So

coming out of the Transition Cluster Study, I believe we went over this in more detail during the Juno hearing. I believe that DEP had a higher cost per unit energy or per kW comparative to DEC. For purposes of the modeling, we averaged them. Public Staff does not take issue with that approach. We believe that is a rough level magnitude or approximation of transmission upgrades across the system because we don't know exactly what projects are going to interconnect, so the numbers is rooted in the results of the transition cluster study.

A. (Mr. Thomas) If I can just clarify that, you know that the transition cluster study, that formed the basis, of my understanding, like Mr. Metz said, formed the basis for the transition adders used in the model. That transitional cluster study triggered some, you know, but not all of the Red Zone upgrades. So yeah, to that extent, some of those were included and then some were not. If they weren't triggered by the TCS, the Transitional Cluster Study, then I don't believe they would have been included in that calculation of the Transmission Cost Adder.

Q. Okay. Did you-all hear the panel provide its testimony on the Supplemental Study it did, which I think of it as the 5400 study, but it was the 1900 in DEC and the 30 whatever, 30 plus in DEP? And did you-all take any issue or have anything to add to their testimony on that study and what it adds to this on this issue?

Q. (Mr. Metz) Part of that study -- so we met and had conversations with the Duke team on that overall study and addressed to them some of our observations or concerns, as it is more detailed in Mr. Robert's and Ms. Farver's testimony. They addressed those concerns. That study kept the 60/40 split at the same allocation that was set forth or prescribed within the model of the Carbon Plan, and it looked at both the historic part both inside and outside the red zone, and we tried to address what were the most common upgrades that we have historically seen. And again, in my opinion, a strong -- a positive item that came out of here is we looked at inside and outside the red zone, and we came up with the most common or in this case as referred to the most least regrets transmission upgrades that we can partake within the Carolina system.

A. (Mr. Thomas) If I could just add, I don't want to necessarily speak to -- for Mr. Metz, but he addressed this in his testimony. I don't think we view -- the Supplemental Transmission Study was definitely helpful in helping to confirm that least regrets path for the red zone, but we didn't view it as necessarily replacing the other recommendations Mr. Metz made in his testimony regarding proactive transmission planning. It's kind of like a stop-gap measure to validate this first step, but we still need to look at, you know, this longer term planning for the transmission system.

A. (Mr. Metz) And it was also identified, I believe Commissioner Clodfelter had highlighted this during his questions, there are still more upgrades there. In my view, we are addressing the backbone of the system, if you would, to the extent that we've had continued upgrades or continued projects, seek interconnection in these areas. There will be more upgrades. There will be more upgrades. And as we move forward, and that's what I think Mr. Thomas' point too, is we need to be looking at the next set. What is the step after this? This is going to help us transition to this point. But if we want to continue this pace of growth, we need to look at the next set, we need to look at where it's going and start planning accordingly.

Q. So have you-all started that yet?

A. No, I have not.

Q. And how do you do that?
A. Working on that.
Q. Okay.
A. I look forward for input from the transmission operators and as well as others.
Q. So when you say "proactive transmission planning," what specifically do you mean? How does that distill down into action items?
A. So a hypothetical. Let's say we're looking at the next set of upgrades and we want an additional 5 gigawatts of solar. And let's say we want it all located in a concentrated area, and let's just specify DEP in the southeast. We would take that back to Duke Energy planning folks and say how can we potentially accomplish this task, and let's start talking about it now what upgrades would occur. And it's not to scare the Commission but to the extent to say, okay, the system is now at a saturation point. We cannot do more on our existing 230 kV system or we cannot do more on our existing 500 kV system. We now have to build a new line. And let's say that's a new 500 kV line. That is a decade plus process, and all of the challenges and hurdles, and most likely potential multiple-state implications as we transition a potential new line,

whether 230 or 500 kV. So that's what I'm talking about, prior upgrades. I mean, this is a good first step, but what's next? So again, if the Commission said do you want to procure, go for the offshore wind and you set a potential target, well, it's important to understand. I mean, I think -- I can't speak for the Duke folks, but at least for me, you want 800 megawatts or do you want 5000 or do you want 2500 megawatts? That input will help provide proactive planning. And to the extent that it can be locational guidance on top of that, we even -- more facilitative, more narrow focus and how we can evaluate smaller -- have a smaller lens, if you would, to look at a two-state system across multiple lines.

Q. Okay. Mr. Thomas, are you wanting to add something?

A. (Mr. Thomas) I just wanted to -- we did discuss this a little bit on about page 113 and 114 of our initial comments. I was looking back at some of that, and we were talking about, you know, potentially, you know, making sure that it's expanding its horizon for transmission planning and working with NCTPC to ensure that the Carbon Plan results are kind of factored into its future planning. To, you know, the extent that location may not be known, but there are tools that

Duke has used and presented in this model that kind of show where solar is likely to be located, where the best potential is, and trying to map that, and without the -- we also spent a lot of time here talking about transmission. So I'd be remiss to not mention that we're also very concerned about the cost burdens on DEP ratepayers associated with significant build-outs of the transmission system in DEP's territory to assist in meeting the Carolina's Carbon Plan, and we want to make sure that that's addressed as well.

Q. So should I ask my questions about that issue to you-all or should I -- I was holding them for Mr. McLawhorn, but should I hold them?

A. (Mr. Metz) You can ask and we might defer.

Q. Okay. So one last question, Mr. Thomas, going back to something you said. The dynamism on the SPS solar plus storage dispatch, you said it was very -- I think your words were very impactful. You might have just said impactful, so, you know, why?

A. (Mr. Thomas) So the way that Duke modeled it originally was they used these -- I think I've explained this before. They used the pricing periods established in avoided cost to kind of say well, charge during these times times and discharge in those times. And that generally recognizes that there's a need for capacity in the winter morning and, you know, it kind of reacted like that, but it set those throughout the whole planning horizon.

The ratepayers that were set in Sub 158 and approved in Sub 167 reflect no onshore wind, no offshore wind. You know, they reflect a lot more coal generation. You know, there was kind of a historical look back based on that. And so as the system changes, when you get more onshore wind, you know, or even offshore wind, or SMRs, the need for that winter capacity right then is -- that solar and storage might be providing -- it might be diminished somewhat. You might need to discharge it at other hours of the day.

So I think that allowing the model to pick and choose how it dispatches those storage, to me, I think it was probably one of the most material changes to resource selections. It was likely -- it likely was one of the most contributing factors to the changes in resource selections that we saw in SP-5. And that's not only the shift away from stand-alone solar to stand-alone solar plus storage, I think that, in and of itself, you know, is an acknowledgement that it was more valuable to the system to be able to dispatch that, but also how it shifted around other resources and even delay the CC. I mean, I'm not saying that's the only reason, but I do think that that contributed to being allowed to dispatch those, you know, hundreds and even thousands of megawatts of storage.

Q. Okay. All right. Thank you-all for -- oh, Mr. Williamson, I do have one for you. I'm not going to let you off the hook. Do you -- what can you tell me about the level of coordination between Duke and its wholesale customers on load management activities?

A. (Mr. Williamson) So the -- I'm going to try and refresh my memory a little bit. I know I talked about it in my testimony. Maybe it was just briefly. So the only information that I can provide you on, I guess, my knowledge of the conversations that Duke's having with its wholesale customers is -- and it might -- it might be applicable, it might not be applicable, but it's just the conversations from -- well, I guess -- I'm going to take that back. I'm confusing the wholesale customers with the industrial customers, so, I'm not aware of any conversations that are going on between the wholesale customers and Duke specifically on load management.

Q. Okay.

CHAIR MITCHELL: All right. Thank you for that. That's it for me. Go ahead.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Mr. Thomas, one follow-up on the Chair's questions about EnCompass capabilities. Do you have any opinion about whether it would be worthwhile, worth the effort, worth the brain cells, worth the money, to add functionality in EnCompass that would allow the model to -- to model bi-directional charging of batteries?

A. (Mr. Thomas) I do. I think that could be valuable either as a --

Q. Is it worth the effort?

A. So I think the fact is it's not -- it's worth the effort for APS, for Anchor Power Solutions, but they're the ones who would have to probably write the code and implement that. But yeah, I think that would be worth it, maybe even to completely replace, you know, the DC only that can only charge from the solar array, and I think that would be very worth it. I hope Anchor Power Solutions implements that. I know at the last user's meeting, they mentioned that that was hopefully an upcoming addition, so...

Q. So they're working on it now?
A. I believe so.
Q. Okay.
A. That's what they told us.

COMMISSIONER CLODFELTER: That's fine. Thank you.

THE WITNESS: Okay.

CHAIR MITCHELL: Go ahead.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. So one follow-up on the proactive transmission planning. What are y'all's views on GETs, you know, the Grid Enhancing Technologies' dynamic line ratings as well as the -- I'm not getting this right, but the cable laying, that may be more expensive but, you know, can provide for more power flow?
A. (Mr. Metz) So Duke Energy, Duke Energy Progress, Duke Energy Carolinas already have different programs of dynamic line rating in place and using today. Now, there are differences between the two programs and they can probably explain better because I'll probably get them mixed up, but there may be some more synergies that they can leverage off their existing programs. I'm not saying their existing programs are wrong. There's always a potential for improvement.

In terms of GETs, Grid Enhancing Technologies, it is a potential solution. I have my reservations of the large scale deployment that could be done and what cost savings could occur. If you look at -- if we're deploying a technology to overcome a NERC standard, well what happens if that technology fails? What happens is if on that day, on that hot day or that cold day, that technology fails? What it can do -- I don't understand the relationship how Duke will need to model that. To me, that's still an N minus 1 failure. So I have a line rating, I want to use this technology. What happened if technology fails? Are we right back to the ground zero? Was that an approved investment if we have to plan if it fails? So I don't understand that relationship strong enough at this point in time. I missed the third question that you had.

Q.   It was the -- and I'm probably using the wrong words, but the cable laying that can enhance power flows.

A.   Yes. So there's different types of cable layings, and I'll just try to simplify it to two. ACSR and ACSS. ACSS will typically allow you more current-carrying capability, and review sort of through some of the plans that Duke had listed within the SERPT TP process.

Some of those upgrades are already underway notably in Duke Energy Carolinas area, and already in the red zone or employing the ACSS. And I can point to a couple examples if you want me to, but other than a system, Duke is implementing it.

COMMISSIONER DUFFLEY: Okay. That's sufficient. Mr. Thomas.

A. (Mr. Thomas) I was going to say, you know, just at a high level, I think the Public Staff would support implementation of cost-effective and reliable technology that could help avoid some transmission upgrades or transmission constraints, as long as it's cost-effective and maintains system reliability.

A. (Mr. Metz) I agree.

COMMISSIONER DUFFLEY: Okay. Thank you.

CHAIR MITCHELL: Go ahead.

EXAMINATION BY COMMISSIONER HUGHES:

Q. I'll place a real quick question. The PVRR calculations, you've talked about what's in EnCompass and what's not. Is that coming directly out of EnCompass or are you taking a stream of investments and handing it over to someone with a big monster spreadsheet?

A. (Mr. Thomas) So the PVR that is presented in Duke is composed of -- and I'll try to keep this as high-level as I can, is composed of multiple categories like new generation capacity at revenue requirement and new transmission capacity, and EE and DSM, and production costs. Generally, when you cut in that PVR, the only thing that's really coming out of EnCompass is the production costs, any carbon costs if those were included, and fixed fuel demand costs. Other than that, like the new generation, capital costs, the revenue requirement for transmission, EE/DSM, those are all calculated in the big monster spreadsheet. That's kind of external to the model.

My understanding is that the model -- if you go to the proper financial characteristics into it, and inputs, and it could kind of spit you out those numbers, but, you know, I also recognize that the way that Duke's doing it now is the way that they did it in System Optimizer and ProSEM, and so they're using tools that are familiar to them as they make this transition, but I'd hope to see them utilize more of the EnCompass, innate functionality that calculate these financial outputs in the future.

Q. So when you were looking at the results of those, and there's debates about, you know, which scenario is more expensive and that -- and we're all looking at the PVRR, that is partially and output of EnCompass, but then that's a financial model that includes assumptions about discount factors and, you know, various streams, various finance assumptions. Is that --

A. Yeah, generally. I mean, it's still linked to EnCompass in that the generation and transmission, PVR, you take the Capacity Expansion Plan, and when are you placing these units in service, and what year, and how many megawatts, and you plug those into a spreadsheet, and then it calculates, you know, the levelized fixed charge rate and the discount rate, and any long-term and short-term costs, and it kind of puts it in an annual cumulative revenue climate out through time, and then that's discounted back to give you the PVR. So it's linked to EnCompass, but I can't take -- you know, EnCompass puts output in Excel. I can't go to that Excel spreadsheet and somewhere figure out what is the actual new generation PVRR. So just -- it's just an extra step that's kind of -- it results in kind of some difficulties in, you know, being able to quickly analyze EnCompass data in a way that doesn't require multiple spreadsheets and linked calculations.

Q. Okay. I have a few other questions, but I think I'm going to hold off to other witnesses.

COMMISSIONER HUGHES: Thank you. That's very helpful.

CHAIR MITCHELL: Questions on Commissioner's questions, if there are any.

MS. GRUNDMANN: Yes, your Honor, I do. Yes, Chair Mitchell.

EXAMINATION BY MS. GRUNDMANN:

Q. Good afternoon, gentlemen. I just wanted to follow up with Chair Mitchell's questions about whether there were things that -- I think she phrased it as were there things the Commission could order that would assist in addressing the issues in utilizing EnCompass? Would it be helpful if the Commission ordered the Company's staff and other interested modeling partners -- parties to meet relatively soon after the Commission were to issue its Order on the 2022 Carbon Plan to discuss inputs that might be run through EnCompass models for purposes of the 2024 plan?

A. (Mr. Thomas) Sorry. You said meeting after this Order in preparation for 2024 or --

Q. Would it be possible -- would it be helpful if the parties could sort of narrow their areas of disagreement and sort of agree on what inputs the

Companies would model when the time came for them to actually begin the modeling process for the 2024 Carbon Plan?
A. Yeah. I mean, I think that would be helpful. I'm always a fan of collaboration. You know, Duke has held multiple models, meetings with modelers to kind of work out some of these issues both after and even before to kind of prepare, so I think that would be helpful to sit down and always --
Q. Well, let me clarify. Specifically, what I mean is for the parties to agree that Duke is going to model X, Y, or Z amounts of solar, solar plus storage, whatever, to see if you could reach a consensus position on what Duke would model, specifically.
A. You mean like the modeling inputs, like capital costs and stuff like that?
Q. Correct.
A. I mean, we had multiple stakeholder meetings, both larger groups and smaller groups, to focus on, you know, some pretty granular data in terms of the costs and stuff like that. I don't think it's possible to reach agreement on all these inputs before the Carbon Plan was filed. If it was, we wouldn't be here right now. So to the extent that there are things we can

agree on, sure. I think that would be helpful or sources, but I think the stakeholder process that we had here with -- I think it was three bigger meetings and then some more technical breakout meetings. I think that was very helpful. And if that's kind of what you're -- that was all before the Carbon Plan was filed. If that's what you're envisioning, I support it. But if we're seeking like that degree on the dollar per kW value for solar before Duke runs any models, I just -- I don't think that's possible.

MS. GRUNDMANN: Okay. Thank you. That's the only question I had.

EXAMINATION BY MS. CRESS:

Q. Good afternoon, gentleman. Mr. Williamson, you were asked a couple questions by both Commissioner Hughes and Commissioner McKissick regarding EE/DSM measures, including some questions about different buckets of funding for those measures. Do you recall those questions?

A. Are you talking about the IRA?

Q. That's correct.

A. Okay.

Q. Aside from utility-funded EE/DSM measures and separate government subsidy funding like the IRA would provide

for, there's also a third bucket of funding specifically as it relates to opted-out customers investing in their own EE/DSM measures on their own dime. Is that correct?
A. Yes, that's correct. They have industrial, large commercial customers. I mean, they have their own self-service to themselves to make their plans as efficient as possible.
Q. And for the EE/DSM measures that are privately funded by those customers, those costs would not then be recovered through the EE/DSM Rider. Is that correct?
A. Correct. Like I was discussing with Commissioner Hughes, essentially the only dollars that roll through the DSM/EE Rider are dollars that are spent to encourage customers to participate in the utilities programs.
Q. And meaning those privately-funded EE/DSM measures are implemented at no cost to other ratepayers?
A. Correct.
Q. Okay. Is there currently a way for Duke to get credit for non-utility funded EE/DSM measures implemented by opted-out industrial and commercial customers?
A. I'm not sure what you mean by "credit."
Q. Is there a way to -- let me back up. Did you hear the

exchange that was had with Duke witnesses Huber and Duff on this issue?

A. Somewhat. It was a few days ago.

Q. Okay. I'll save the rest for rebuttal for that panel then. Thank you.

CHAIR MITCHELL: All right. Duke. I take that as a no question?

MR. BREITSCHWERDT: Mr. Snowden may have a question, but I do not.

CHAIR MITCHELL: Okay. Do you have questions?

MR. SNOWDEN: Yes, ma'am, just a couple.

CHAIR MITCHELL: All right.

EXAMINATION BY MR. SNOWDEN:

Q. Mr. Metz, I read Mr. Roberts' testimony on the Transmission Panel to take the position that it's important that North Carolina develop a process to integrate resource planning and transmission planning. Did you see that?

A. Yes.

Q. And would you agree with that?

A. Yes, and I think that's some of the findings that were coming out of the Public Staff's public policy request that we submitted to NCTPC.

Q. Okay. Thank you. And so you've been involved -- with the Public Staff, you've been involved with the Transmission Advisory Group, right?
A. That is correct.
Q. Okay. And you had a part in that public policy study?
A. That is correct.
Q. Okay. Based on your experience with TAG and with the public policy study, do you think that it's possible for the NCTPC, on its own, to handle that integrated transmission and resource planning function?
A. Yes. I mean, that primary function, I mean, it's simplified. I mean, it is another model, but a transmission model to essentially look at generation interconnection studies.
Q. Okay. I guess what I'm getting at is, is the TPC equipped to do the resource planning sort of side of the equation?

MR. BREITSCHWERDT: Objection. I think we're well beyond the scope of any specific question now that we're getting into the TPC doing resource planning.

MR. SNOWDEN: I believe Chair Mitchell asked the Panel a couple questions, and I am just trying to get Mr. Metz' perspective on this question. I believe Chair Mitchell asked some questions of the Panel about the TPC specifically, so I'm just following up on that. And I apologize. I don't remember the specific question, but --

CHAIR MITCHELL: I'm not sure I remember asking about the TPC, but it's been a long day, so --

MR. SNOWDEN: It may specifically have been of the integration of resource planning and transmission.

CHAIR MITCHELL: Just ask your -- try to ask one question and then let's move on, get what you need from him.

MR. SNOWDEN: Sure.

BY MR. SNOWDEN:

Q. Can the TPC do -- handle the resource planning side of that integrated planning?

A. I mean, my understanding that coming out of the Carbon Plan should help inform the new generation for evaluating the future upgrades, but at the same token is I don't want to undermine the public policy requests that can also or the other requests that can also potentially look at different resources for potential transmission sensitivities, so to state it different, yes and no.

Q. Okay. Thanks. And do you know of any other states or utilities that are doing integrated transmission and resource planning?

A. I'm not positive of any but I haven't been doing extensive research on the topic.

Q. Okay. Thanks. Mr. Metz, Commissioner Duffley asked you a couple of questions about Grid Enhancing Technologies. Do you remember that?

A. Yes.

Q. And you mentioned specifically dynamic line ratings and you said that Duke was already using dynamic line ratings. Is that right?

A. That's correct.

Q. Okay. Would you agree that Duke is using dynamic line ratings for operational purposes but is not using it for transmission planning purposes?

A. I'm going to have to -- I'm going to stay within my lane. I don't know the answer to that question.

Q. Okay. Thank you. And have you read Duke's comments with regard to Grid Enhancement Technologies, and specifically dynamic line ratings in the FERC NOPR docket on transmission planning?

A. I'm not familiar with it.

Q. Okay.

MR. SNOWDEN: Thanks. Those are all the questions I have.

CHAIR MITCHELL: Okay. Public Staff. Did you have any?

MR. BREITSCHWERDT: No questions.

EXAMINATION BY MR. JOSEY:

Q. Mr. Metz, you got a few questions on red zone projects and proactive transmission planning. Would you agree that the Public Staff came to its position on the subset of red zone upgrades and proactive transmission planning, that proactive transmission planning is needed to alleviate, at least in part, its concerns about continuous upgrading or rebuilding of the same lines due to multiple interconnection requests?

A. (Mr. Metz) In part, yes.

MR. JOSEY: All right. Thank you. That's it.

CHAIR MITCHELL: All right. I think we have come to the end of this Panel's examination. I'll take motions.

MS. LUHR: Chair Mitchell, the Public Staff would move that Metz Exhibit 1 attached to the prefiled direct testimony of Mr. Metz be entered into the record and marked for identification as premarked, and that the testimony summaries of Metz, Thomas, and Williamson prefiled in the Sub 179-A Docket be moved into the record.

CHAIR MITCHELL: All right. Mr. Metz' exhibit will be identified as it was as premarked and it will be admitted into evidence, and the testimony summaries for each of the panelists will be copied into the record as if given orally from the stand at the appropriate time. Any additional motions? Go ahead.

(WHEREUPON, Metz Exhibit 1 is admitted into evidence.)

(WHEREUPON, the prefiled summaries of DUSTIN R. METZ, JEFF THOMAS and DAVID M. WILLIAMSON were copied into the record as if given orally from the witness stand in Transcript Volume 21.)

MS. CRESS: Chair Mitchell, for the purpose of consistent naming conventions, I wanted to ask whether you would like for me to ask that my previously marked and identified exhibits be renamed so that they are consistent with subsequent cross-examination of this Panel.

CHAIR MITCHELL: Okay. Go ahead.

MS. CRESS: Okay. So I would ask that CIFGUR II and III, Public Staff Thomas, Metz, and Williamson Panel Cross-Examination Exhibits 1 and 2 be renamed CIGFUR II and III, Public Staff Panel 1, Cross-Examination Exhibits 1 and 2, and I'd ask for those to be moved into the record at the appropriate time.

CHAIR MITCHELL: All right. The documents will be so identified and they will be accepted into evidence.

MS. CRESS: Thank you.

(WHEREUPON, previously identified CIGFUR II and III Public Staff Thomas, Metz, and Williamson Panel Cross-Examination Exhibits 1 and 2 identified in Volume 21 have been renamed CIGFUR II and III Public Staff Panel 1 Cross-Examination

Exhibits 1 and
2, and are admitted into
evidence.)

MR. BREITSCHWERDT: Duke would ask that Duke Energy Public Staff Panel 1 Cross-Examination Exhibits 1 through 4 be entered into the record.

CHAIR MITCHELL: All right. Motion's allowed.

(WHEREUPON, Duke Energy Public
Staff Panel 1 Cross-Examination
Exhibits 1 through 4 are
admitted into evidence.)

CHAIR MITCHEL: Okay. Anything else?

MR. SCHAUER: Tech Customers would ask that Tech Customers Public Staff Panel 1 Cross-Examination Exhibit 1 be moved into evidence.

CHAIR MITCHELL: All right. Motion's allowed.

(WHEREUPON, Tech Customers
Public Staff Panel 1
Cross-Examination Exhibit 1 is
admitted into evidence.)

COMMISSIONER CLODFELTER: Chair, I would propose that the Commission take judicial notice of the document I asked the Panel about. That's the motion to intervene and comments of Piedmont Natural Gas Company filed in Federal Energy Regulatory Commission Docket No. CP22-461-000 on June 28, 2022.

CHAIR MITCHELL: We will take judicial notice as requested by Commissioner Clodfelter. Anything else before we excuse the witnesses?

(No response)

CHAIR MITCHELL: All right, gentlemen, you may step down. Thank you very much for your testimony today. All right.

MS. LUHR: The Public Staff now calls Panel 2, James McLawhorn and Michelle Boswell to the stand.

CHAIR MITCHELL: As the witnesses approach, I will say we were scheduled to end at 3 o'clock today. In the interest of allowing the Commissioners to attend to other business, we don't have the luxury of ending that early today if we're going to try to get through this hearing, so we're going to go until 5:00. And my hope is that we can get through this Panel as well as the three panelists that have requested to be heard, but we're not going to stay past 5:00, so I'm just letting everyone know for planning purposes. All right. Let me get y'all sworn in.

MICHELLE BOSWELL;

JAMES MCLAWHORN;

having been duly sworn,

testified as follows:

DIRECT-EXAMINATION BY MS. LUHR:

Q. Ms. Boswell, would you please state your name, business address, and current position for the record?

A. Michelle M. Boswell. My address is 430 North Salisbury Street, Raleigh, N.C. I am the Director of Accounting for the Public Staff.

Q. And on September 2nd, 2022, did you prepare and cause to be prefiled direct testimony in this docket consisting of 10 pages and one appendix?

A. Yes.

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

A. No.

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

A. Yes.

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

A. I did.

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

A. My name is James McLawhorn. My business address is 430 North Salisbury Street, Raleigh, North Carolina, and

I'm the Director of the Public Staff's Energy Division.

Q. And on September 2nd, 2022, did you prepare and cause to be prefiled direct testimony in this docket consisting of 23 pages and one appendix?

A. Yes.

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

A. Yes, I do. On page 6, Table 1, the very first line for August 1st, 2007 -- I'll wait and let everybody get there. It's page 6, Table 1. The amount, bill amount shown for DEC should be $86.99 instead of $87.99, so 86.99, and that changes the percent difference in the third column to 9.9 percent.

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

A. Yes.

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, I did.

MS. LUHR: Chair Mitchell, at this time, I move that the prefiled direct testimony and summaries of testimony of Public Staff witnesses Boswell and McLawhorn be entered into the record as if given orally from the stand.

CHAIR MITCHELL: All right. Motion's allowed.

(WHEREUPON, the prefiled direct testimony, Appendix A and summary of JAMES S. MCLAWHORN is copied into the record as if given orally from the witness stand.)

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,	)	**JAMES S. MCLAWHORN**
2022 Biennial Integrated Resource	)	**PUBLIC STAFF –**
Plans and Carbon Plan	)	**NORTH CAROLINA**
	)	**UTILITIES COMMISSION**

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

A. My name is James S. McLawhorn. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am Director of 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 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).

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. Factual issues related to rate disparity, merger, and state alignment;

II. Factual issues consistent with the determination of "least cost" consistent with N. C. Gen. Stat. § 62-110.9; and

III. Factual issues related to the all-in total cost and rate impacts for customers.

Q. PLEASE BRIEFLY SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

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 discuss issues related to the rate disparities between DEC and DEP, the impacts of the Proposed Carbon Plan on those disparities, and actions that can be taken to address the disparities. Specifically, I recommend that the Commission order DEC and DEP to take steps to merge the two utilities into one operating entity. In the interim, I recommend that costs incurred by one utility to meet the statewide carbon reduction goals of N.C.G.S. § 62-110.9 (Section 110.9) be proportionately allocated between the utilities so that the ratepayers of one utility are not unduly burdened with a disproportionate share of the costs to comply. I also address the mandate that DEC and DEP are under already to operate in a "least cost" manner pursuant to N.C.G.S. § 62-2(a)(3a), and the requirement of Section 110.9 that the Commission adopt a Carbon Plan that complies with "least cost" principles. As with the issue of rate disparity, I find the most efficient way to achieve a least cost Carbon Plan is through a full merger of DEC and DEP. Finally, I discuss the present value revenue requirement (PVRR) and bill impacts of the Proposed Carbon Plan, and the fact that DEC and DEP have excluded certain costs common to all portfolios in their analysis and presentation. I recommend that the Commission order Duke to present a PVRR and rate analysis that also incorporates all common costs so that its retail and wholesale customers are able to understand the full costs of Duke's operations over the next 25 years, and not only the incremental costs of Carbon Plan compliance.

I. <u>Factual Issues Related to Rate Disparity, Merger, and State Alignment</u>

Q. WHAT DO YOU MEAN BY THE PHRASE "RATE DISPARITY" IN THE CONTEXT OF THIS PROCEEDING?

A. My usage of this phrase is a direct reference to the differential in rates paid by DEC and DEP customers of similar usage characteristics. On average, DEP's customers pay rates that are substantially higher than those of DEC's customers. As one example, based on rates effective August 1, 2022, a DEC residential customer consuming 1,000 kWh of electricity pays an average monthly bill of $106.23, while a DEP residential customer with the same consumption pays an average monthly bill of $125.94, a difference of $19.71, or 19%. Put simply, while both DEC's and DEP's rates have been found to be just and reasonable, DEP's customers consistently pay almost 20% more than DEC's customers for the exact same service.

Q. WHY IS THERE SUCH A DISPARITY GIVEN THAT BOTH DEC AND DEP ARE ELECTRIC UTILITIES OWNED BY DUKE ENERGY CORPORATION?

A. DEC and DEP are separate utilities, each possessing a unique service territory, customer base, and generation, transmission, and distribution assets. Because rates are set based upon average cost of service, and given the differences listed above, it is not surprising that some rate differentials exist, and in fact they have existed since before the corporate merger of Duke Energy Corporation and Progress Energy Corporation in 2012. However, these rate differentials have grown significantly since the merger in 2012. Table 1 below shows the average residential bills per 1,000 kWh usage for each utility for 2007, 2012, 2017, 2018, 2019, 2020, 2021, and 2022, inclusive of all applicable riders.

Table 1 – Average Annual Residential Bills Per 1,000 kWh Usage

As of:	DEC	DEP	% Difference
8/1/2007	$87.99	$95.56	8.5%
8/1/2012	$105.99	$106.00	0%
8/1/2017	$103.98	$109.93	5.7%
8/1/2018	$100.82	$115.09	14.2%
8/1/2019	$106.50	$120.95	13.6%
8/1/2020	$106.97	$116.63	9.0%
8/1/2021	$106.30	$119.67	12.6%
8/1/2022	$106.23	$125.94	18.6%

It is possible to point to many issues over this time period that have affected DEP's costs and retail rates, such as DEP's purchase of certain jointly owned coal and nuclear assets from the power agencies as mandated in 2015 by N.C.G.S. § 62-133.14, the disparity of DSM/EE Rider amounts,[1] and the implementation of a storm securitization charge[2] as authorized in 2019 by N.C.G.S. § 62-172. However, it is impossible to discount the impact of the significantly greater amount of solar generation that has been developed in DEP's service territory versus DEC's service territory,

[1] DEP residential customers pay a monthly Demand Side Management/Energy Efficiency charge of $7.21 for 1,000 kWh versus $4.77 per 1,000 kWh for DEC residential customers.

[2] DEP's service territory is located closer to the Atlantic Ocean than DEC's service territory, making DEP more susceptible to the impacts of Atlantic hurricanes, as evidenced by the higher current storm securitization charge of $2.27 per 1,000 kWh for DEP residential customers versus $0.37 per 1,000 kWh for DEC residential customers.

which DEP is required to purchase under PURPA, along with associated transmission and distribution system upgrades, particularly in light of DEC's greater load. See Table 2 below for system comparisons.

Table 2 – System Comparisons

Parameter	**DEC**	**DEP**	**Ratio (DEC/DEP)**
Service Territory Square Miles	24,000	29,000	0.83
Owned Capacity (MW)	20,100	12,500	1.61
Retail Customers	2,800,000	1,700,000	1.65
Sales - GWh (2021)	86,880	60,139	1.44
Winter Peak – MW (2021)	17,620	13,413	1.31
Rate Base (2018)	$21,361,527,000	$14,580,739,000	1.46
Rate Base/Customer	$7,629	$8,576	0.89
Rate Base/Sq. Mile	$890,000	$503,000	1.77
Operating Exp. (2018)	$5,681,305,000	$4,727,428,000	1.20
Op. Exp./Customer	$2,029	$2,781	0.73
Op. Exp./GWh	$65,393	$78,608	0.83
Annual Fuel Cost 12 months ended 6/30/2022 - $/MWh	$26.756	$28.060	0.95
DSM/EE Rider - $/MWh	$4.77	$7.21	0.66
Sited Solar Gen. - MW	1,400	3,300	0.42
Solar Gen./Peak	0.08	0.25	0.32

Q. YOU MENTIONED THE AMOUNT OF SOLAR GENERATION THAT HAS BEEN DEVELOPED IN DEP'S TERRITORY VERSUS DEC'S TERRITORY. WHY HAS THE DEVELOPMENT BEEN DISPROPORTIONATE?

A. Based on conversations with solar developers, land in certain areas of DEP's service territory is preferable to developers due to its general availability, more favorable topography, and lower cost. Despite DEP being approximately 60% to 70% of the size of DEC in terms of customers and load, its service territory is approximately 20% larger geographically, indicating that, overall, DEP's service territory is less densely populated than DEC's.

Q. WHY ARE YOU RAISING THIS ISSUE AS PART OF THIS CARBON PLAN PROCEEDING?

A. Up to now, while the increasing cost pressure on DEP's retail rates was a concern, the solar development in DEP's service territory was largely a function of individual business decisions by developers to build and accept compensation from DEP at traditional avoided cost rates. With the passage of Section 110.9, there is now a <u>statewide mandate</u> for the Commission to adopt a plan by which DEC's and DEP's combined system will achieve a 70% reduction in carbon dioxide emissions from 2005 levels by 2030,[3] and carbon neutrality by 2050 (Carbon Plan), including through the development of additional significant amounts of solar generation. Much of the new solar generation will be developed with paired storage. In addition, both onshore and offshore wind resources are likely to be developed as well. It is anticipated that DEP's service territory will continue to be the focus for solar and solar plus storage (S+S) resource development. DEP's service territory is also the likely location for much, if not all, of the onshore wind development, and any offshore wind generation will require significant transmission development and upgrades on DEP's system.

However, DEC and DEP have proposed a Carbon Plan without regard to whether the additional planned generation for meeting the carbon reduction requirements will be located in DEC's or DEP's service territory.[4] The Carbon Plan that is ultimately adopted by the Commission will be a statewide plan and Section 110.9 is neutral as to how or where Duke reduces carbon emissions in North Carolina,

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[3] Unless extended by the Commission, as allowed by Section 110.9(4) under certain enumerated circumstances.

[4] As noted in the testimony of Public Staff witness Metz in this proceeding, 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. This modeling limitation is not imposed on other resources that could be used for Carbon Plan compliance purposes, nor does it limit the actual development of solar resources.

so long as the combined carbon emissions of DEC and DEP in North Carolina hit the targets required by law.

If DEC and DEP continue to operate in business-as-usual mode without merging, DEP's retail customers will absorb a disproportionate share of the costs to achieve statewide compliance with the Carbon Plan.[5] With retail rates already approaching a 20% disparity with DEC, business-as-usual will continue to harm DEP's customer base from an economic standpoint. Moreover, because electricity costs are a substantial cost for large businesses and industry, it will become increasingly difficult, if not impossible, to recruit new economic development into DEP's service territory, and the higher electricity costs will likely drive out existing businesses.

Q. GIVEN THE BLEAK OUTLOOK YOU HAVE DESCRIBED, WHAT CAN BE DONE TO LESSEN THE IMPACTS OF THE CARBON PLAN ON DEP'S CUSTOMERS?

A. The first step is to "stop the bleeding." While existing rates cannot be altered and have little to do with the Carbon Plan,[6] there needs to be

[5] See Table 3 below for a portfolio comparison of monthly bill impacts for compliance with the Carbon Plan for DEC and DEP customers. Portfolio 3, which is identified as the "least cost" portfolio, has a monthly bill increase for DEP customers that is 2.7 times the increase for DEC customers. The other three portfolios shown have bill increases for DEP versus DEC customers that range from 3.6 times to 5.8 times.

[6] Some of the solar development activities that are already underway and already reflected in rates will help Duke to achieve the interim compliance goal of a 70% reduction in carbon emissions from 2005 levels.

a way to equitably share costs incurred to comply with the statewide Carbon Plan between DEC and DEP, regardless of where the activities related to the incurred costs are physically located. For instance, if a 500 kV transmission line is built in DEP's service territory to facilitate additional solar and wind generation required by the statewide Carbon Plan, DEC should be allocated a proportionate share of those costs. How that allocation would be determined is unclear at this moment. Transmission plant has historically been allocated among the utility's jurisdictions and customer classes on the basis of coincident peak demand. A cross-utility allocation of transmission plant is a new phenomenon which could include other inputs such as certain carbon emission reductions from certain generating facilities or other benefits that are unique to one service territory or the other. Such an allocation of costs and benefits and how they would impact rates is undetermined at this time.

The Public Staff recommends that the Commission require Duke to work with the Public Staff and other interested parties to develop a plan for appropriately allocating Carbon Plan costs between DEC and DEP until the Companies merge. Requests for recovery of such costs will first come before the Commission in the Companies' upcoming rate cases, and an equitable allocation method must be determined as soon as possible.

Throughout the Carbon Plan development process, DEC and DEP have discussed the idea of merging their balancing areas from an operational standpoint. If possible, this would more efficiently remedy operational issues, reduce certain costs overall, and improve reliability. However, merging the balancing areas will do little to address capital costs incurred to develop resources sited in DEP's service territory that are disproportionately allocated to DEP customers, despite their benefitting both DEC and DEP customers. Ultimately, the answer to these issues is not merging the balancing areas, but merging the two utilities, thus eliminating the need to address cost allocation issues between the two balancing areas.

Q. BECAUSE DEP'S RETAIL RATES ARE ALREADY SIGNIFICANTLY HIGHER THAN DEC'S RETAIL RATES, WOULD A FULL MERGER BENEFIT DEP'S CUSTOMERS MORE THAN DEC'S CUSTOMERS?

A. That is a possibility, but it is not necessarily so, at least initially. While it can be argued that DEC's customers have benefited, in part, by the solar development in DEP's service territory, and thus it is only fair that they begin to pay a portion of those costs, a merger of utilities does not require the imposition of uniform rates at the outset. In 1988, DEC acquired Nantahala Power and Light (NP&L) as a subsidiary, and in 1998 merged NP&L into DEC, creating a single utility.[7] However, legacy NP&L and DEC customers maintained separate rates at the beginning. As DEC rates changed over a period of years, NP&L rates were gradually brought to parity with DEC rates, until the rate differential disappeared, and separate rates were no longer necessary. The same or similar ratemaking approach could be undertaken with a merger of DEC and DEP; in the interim, new rate base and associated costs needed to comply with the Carbon Plan would be allocated to both sets of rates proportionately to ensure that legacy DEC and legacy DEP customers are paying for their full costs to comply with the statewide Carbon Plan, but no more.

Q. WOULD SIGNIFICANT EFFORT BE REQUIRED TO TRACK COSTS AND RATES IN THIS MANNER DURING OR AFTER THE MERGER?

A. While not ideal, DEC and DEP already maintain separate rate bases, rate structures, and rates. When they apply for a general rate case, or new tariffs or changes to existing rates and tariffs outside of general rate cases, separate filings are made for each utility, causing significant burdens on Duke staff. In addition, the Commission and Public Staff, as well as other intervenors, are required to expend duplicative effort to handle each utility separately. A full merger of the

[7] Docket Nos. E-7, Sub 614 and E-13, Sub 178.

utilities will eliminate much of this burden, if not initially, then over time.[8] A full merger of rates would be preferable from an administrative standpoint, but the Public Staff understands that this may not be the most equitable approach on day one. However, while this issue is something for the Commission to address in a future proceeding, the process must begin now. It was the Public Staff's understanding and belief at the time of the 2012 corporate merger that the individual utilities would merge within five years, but already over a decade has passed without meaningful progress. In order to equitably implement a Carbon Plan between DEC and DEP customers, this issue must be prioritized. One of the objectives the Public Staff had in recommending a comprehensive rate study in the last general rate cases of both DEC and DEP was to begin evaluating existing tariffs and rate structures that might serve as a launch pad for future merger.[9]

[8] A full merger would also likely eventually result in the filing of only one set of annual riders rather than two, reducing the workload of the Commission, the Companies, intervening parties, and the Public Staff.

[9] See Testimony of Public Staff witness Floyd, in the consolidated issues hearing in Docket Nos. E-2, Sub 1219 and E-7, Subs 1213 and 1214. Volume 10, page 103-110.

Q. WHAT RECOMMENDATIONS DO YOU HAVE REGARDING THE RATE DISPARITY BETWEEN DEC AND DEP CUSTOMERS AND MERGER OF THE TWO COMPANIES?

A. I reiterate the Public Staff's recommendation in its Initial Comments on this issue, to wit: "that Duke should promptly evaluate the steps necessary to consolidate the DEC and DEP utilities into a single operating entity and present the Commission with a timeline for implementation."[10] In addition, I recommend that the Commission instruct Duke to take immediate steps to allocate all Carbon Plan costs proportionately between DEC and DEP to ensure that DEP customers do not disproportionately bear costs incurred to achieve system-wide carbon reductions, and that the Commission require the Companies to work with the Public Staff and other interested intervenors to develop a plan for this allocation.

Duke witnesses V. Nelson Peeler, Jr. and Laura A. Bateman filed joint testimony in this proceeding on August 19, 2022. In their joint testimony, the witnesses provide a potential merger timeline in their Exhibit 1. I find their potential timeline to be reasonable. I recommend that the Commission order the utilities to begin implementing plans to merge DEC and DEP into a single utility as soon as reasonably practicable. If the Commission declines to order the immediate

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[10] Public Staff Initial Comments, p. 164.

merger, I encourage the utilities to begin pursuing it immediately on their own. To fail to do so may result in requests from the Public Staff that certain costs incurred to comply with the Carbon Plan be deemed imprudent.

II. Factual Issues Consistent with the Determination of "Least Cost" Consistent with Section 110.9

Q. ARE DEC AND DEP ALREADY UNDER A MANDATE TO OPERATE ON A "LEAST COST" BASIS?

A. Yes, N.C.G.S. § 62-2(a)(3a) declares that it is the policy of the State of North Carolina:

> To assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the **least cost** mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills.

(Emphasis added).

Likewise, Section 110.9 provides that, in developing a Carbon Plan that meets the emissions reduction targets in the statute: the Commission must "achieve the **least cost** path"; the Commission must "[c]omply with current law and practice with respect to **least**

cost planning for generation, pursuant to [N.C.G.S. §] 62-2(a)(3a)"; new solar generation selected by the Commission shall be "in adherence with **least cost** requirements"; and the Commission "[r]etain[s] discretion to determine optimal timing and generation and resource-mix to achieve the **least cost** path to compliance with the authorized carbon reduction goals" (emphasis added).

Thus, while DEC and DEP have a mandate to operate on a least cost basis as separate utilities, there is now a statutory mandate to develop a statewide Carbon Plan that meets least cost principles. DEC and DEP, whether as separate utilities or as one single merged utility, are under a mandate to comply with Section 110.9 on a "least cost" basis. The most efficient way to achieve this mandate is through joint planning, which can best be accomplished through a full merger of DEC and DEP.[11]

III. Factual Issues Related to All-in Total Cost and Rate Impacts for Customers

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[11] Regulatory conditions imposed in the Commission's Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, dated June 29, 2012, in Docket Nos. E-2, Sub 998 and E-7, Sub 986 require DEP and DEC each to pursue least-cost integrated resource planning and file separate Integrated Resource Plans until required or allowed to do otherwise by Commission order or until a combination of the utilities is approved by the Commission.

Q. PLEASE SUMMARIZE THE PVRR AND BILL IMPACTS PRESENTED IN THE PROPOSED CARBON PLAN.

A. The PVRR and bill impacts of each portfolio in the Proposed Carbon Plan are discussed in the Public Staff's Initial Comments and are summarized in Table 3 below. The Least Cost (LC) portfolio is P3.

Table 3 – Cost and Rate Comparisons for Proposed Portfolios

Portfolio – 70% Year	PVRR 2035 ($B)	% Over LC	PVRR 2050 ($B)	% Over LC	Monthly Bill Increase (2030)	
					DEC	DEP
P1 – 2030	47.3	7.6%	101.1	6.2%	$8	$35
P2 – 2032	45.5	3.6%	98.8	3.7%	$5	$29
P3 – 2034	44.0	LC	95.2	LC	$7	$19
P4 – 2034	44.0	0.3%	95.5	0.3%	$5	$18

Q. HOW DO THE ESTIMATED COSTS VARY ACROSS PORTFOLIOS?

A. The estimated PVRR for P1 is substantially higher than other portfolios, and the estimated increase to retail bills by 2030 is significant. As discussed in the Public Staff's Initial Comments, P1 is also most susceptible to cost overruns due to its extremely aggressive interconnection schedule for solar and S+S resources and its heavy reliance on these resources.[12]

[12] Public Staff Initial Comments, p.18.

Q. DO YOU HAVE ANY CONCERNS WITH THE WAY THE PVRR AND RETAIL BILL IMPACTS WERE CALCULATED?

A. No, the Public Staff does not have concerns regarding the calculations of PVRR and retail bill impacts. However, the Public Staff does have larger concerns about Duke's PVRR and retail bill analyses, as discussed below.

Q. DO YOU BELIEVE THE PVRR AND RETAIL BILL IMPACTS, AS PRESENTED IN THE PROPOSED CARBON PLAN, PROVIDE A CLEAR PICTURE OF THE ACTUAL COSTS RATEPAYERS WILL BEAR?

A. No. There are many costs not included in the retail bill impacts that are common across all portfolios, such as costs associated with the Red Zone Transmission Expansion Plan, Grid Improvement Plan, storm securitization costs, fixed operations and maintenance of existing plants, and the costs of subsequent license renewals for existing nuclear plants.[13] Thus, the retail bill impacts are likely substantially understated, as recognized by other intervenors.[14]

[13] *Id.* at 79.

[14] See, e.g., CIGFUR Initial Comments, pp. 12-19.

Q. WHY DO YOU BELIEVE DUKE MAY HAVE UNDERSTATED THE ACTUAL COSTS RATEPAYERS WILL BEAR TO IMPLEMENT DUKE'S PROPOSED CARBON PLAN?

A. As explained in the testimony of Duke witnesses Glen A. Snider, Robert A. McMurry, Michael T. Quinto, and Matthew Kalemba (Modeling Testimony), the PVRR and retail bill impacts are intended to be a comparison metric only, and are not designed to provide the Commission and stakeholders with the full picture of costs ratepayers will bear.[15] As such, the PVRR and retail bill impacts do not give a clear sense of the actual costs ratepayers will bear if the Commission adopts Duke's Proposed Carbon Plan.

Q. DO YOU AGREE WITH WITNESS QUINTO'S TESTIMONY THAT INCLUDING ADDITIONAL COSTS COMMON TO ALL PORTFOLIOS IS UNNECESSARY AND POTENTIALLY COUNTERPRODUCTIVE TO THE EXTENT THAT IT COULD OBSCURE THE EFFECTS OF INVESTMENTS THAT DIFFER ACROSS PORTFOLIOS?

A. No. While it is true that including common costs would increase the PVRR of all portfolios by the same amount and therefore reduce the percentage differences between each portfolio, this is not a barrier to comparative portfolio evaluation. The Public Staff is not requesting

[15] Modeling Testimony, p. 97.

that Duke <u>only</u> submit PVRR and bill impact estimates that include common costs. Nothing in the Public Staff's recommendations prohibit Duke from providing relative PVRR and bill impacts for comparative portfolio analysis <u>in addition</u> to "all-in" PVRR and bill impacts. I view this recommendation as being both necessary and productive.

Q. WHY IS IT IMPORTANT TO CONSIDER THE IMPACTS OF COMMON COSTS ON RETAIL RATES?

A. It is important for stakeholders, particularly those representing retail and wholesale customers, to understand the full costs of Duke's operations over the next 25 years. The Proposed Carbon Plan is more than simply a plan to comply with the carbon reduction goals in Section 110.9; it is essentially a comprehensive Integrated Resource Plan, expanded in scope and level of detail to encompass carbon dioxide limits and reliability. The Proposed Carbon Plan, and the Commission's Carbon Plan that is ultimately adopted, represent a vision for the future. Without understanding the "all-in" costs of achieving this vision, stakeholders may believe the transition is far less expensive than it appears.

In addition, as outlined in the Public Staff's Initial Comments, the exclusion of fixed costs from existing generation plants artificially suppresses operational costs in the near term and masks an analysis of tradeoffs between capital costs and production costs associated with renewable resources.[16]

Q. DO YOU BELIEVE THE PVRR AND BILL IMPACT ANALYSIS SHOULD INCLUDE COSTS THAT ARE COMMON TO ALL PORTFOLIOS?

A. Yes. In addition to the cost categories outlined above, because riders comprise a substantial portion of every retail bill, consideration should be given to their inclusion as well.

Q. PLEASE SUMMARIZE HOW THE ESTIMATED PVRR AND RETAIL BILL IMPACTS HAVE CHANGED UNDER SP5 AND SP6.

A. The PVRR results are presented in Duke's Modeling Testimony Exhibit 1 and are summarized in Table 4 below. SP5A and SP6A utilized the base assumptions regarding access to Appalachian gas that were used in the development of P1 through P4. As in prior cost analysis, it is clear that factors such as the interim compliance year and whether Appalachian gas becomes available are significant drivers of the final PVRR and retail bill impacts. For example, the PVRR of SP5 is nearly the same as the PVRR of P2-Alt, both of which met the interim compliance target by 2032 and included similar restrictions on Appalachian gas.

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[16] Public Staff's Initial Comments, p. 81.

Table 4 – Cost and Rate Comparisons for Supplemental Portfolios

Portfolio – 70% Year	PVRR 2050 ($B)	Monthly Bill Increase (2030)	
		DEC	DEP
SP5 – 2032	$101.7	$17	$20
SP6 – 2034	$98.4	$12	$18
SP5A – 2032	$97.8	$6	$24
SP6A – 2034	$94.7	$4	$19

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

JAMES S. MCLAWHORN

I graduated with honors from North Carolina State University with the Bachelor of Science Degree in Industrial Engineering in May of 1984. I received the Master of Science Degree in Management with a finance concentration from North Carolina State University in December of 1991. While an undergraduate, I was selected for membership in both Tau Beta Pi and Alpha Pi Mu engineering honor societies.

I began my employment with the Electric Division of the Public Staff in November of 1988. I became Director of the Electric Division in October of 2006, and, with the merger of the Electric and Natural Gas Divisions, I assumed my present position as Director of the Energy Division in August of 2020. It is my responsibility to supervise and make policy recommendations on all electric and natural gas utility matters that come before the Commission.

I have testified previously before the Commission in numerous proceedings.

The Public Staff – North Carolina Utilities Commission
Summary of the Testimony of James S. McLawhorn
Docket No. E-100, Sub 179

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 first discuss issues related to existing rate disparities between Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP), the impacts of the Proposed Carbon Plan on those disparities, and actions that can be taken to address the disparities.

Currently, the residential rates of DEP are approximately 19% higher than those of DEC, as show in Table 1 of my testimony. I explain that the statewide Carbon Plan will impose costs disproportionately on the customers of DEP, and I recommend actions to address this inequity. Specifically, I recommend that the Commission order DEC and DEP to take steps to merge the two utilities into one operating entity. In the interim, I recommend that costs incurred by DEP to meet the statewide carbon reduction goals of N.C. Gen. Stat. § 62-110.9 (Section 110.9) be proportionately allocated between DEC and DEP, so that the ratepayers of DEP are not unduly burdened with a disproportionate share of compliance costs.

I also address the existing mandate that DEC and DEP operate in a "least cost" manner pursuant to N.C.G.S. § 62-2(a)(3a), and the requirement of Section 110.9 that the Commission adopt a Carbon Plan that complies with "least cost" principles. As with the issue of rate disparity, I explain that the most efficient way to achieve a least cost Carbon Plan is through a full merger of DEC and DEP.

Finally, I discuss the present value revenue requirement (PVRR) and bill impacts of the Proposed Carbon Plan, and the fact that DEC and DEP have excluded certain costs common to all portfolios in their analysis and presentation. I recommend that the Commission order Duke to present a PVRR and rate analysis that also incorporates all common costs so that its retail and wholesale customers are able to understand the full costs of Duke's operations over approximately the next 25 years, and not only the incremental costs of Carbon Plan compliance.

This concludes my summary.

(WHEREUPON, the prefiled direct testimony, Appendix A and summary of MICHELLE M. BOSWELL, is copied into the record as if given orally from the witness stand.)

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,	)	**MICHELLE M. BOSWELL**
2022 Biennial Integrated Resource	)	**PUBLIC STAFF –**
Plans and Carbon Plan	)	**NORTH CAROLINA**
	)	**UTILITIES COMMISSION**

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

A. My name is Michelle M. Boswell. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am the Director of the Accounting Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. A summary of my qualifications and duties is set forth in Appendix A of this testimony.

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. 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).

Q. HOW IS YOUR TESTIMONY ORGANIZED?

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

I. Coal unit securitization;

II. Deferral of project development costs;

III. Whether nuclear development project costs are recoverable pursuant to N.C. Gen. Stat. § 62-110.7; and

IV. Cost recovery of "long lead time resources" ultimately determined not to be necessary to achieve the energy transition and the carbon dioxide (CO_2 or carbon) emission reduction targets of S.L. 2021-165 (referred to herein as House Bill 951 or HB 951), codified as N.C.G.S. § 62-110.9 (Section 110.9).

I. <u>Coal unit securitization</u>

Q. WHAT IS THE PUBLIC STAFF'S POSITION REGARDING THE SECURITIZATION OF RETIRED COAL UNITS?

A. Public Staff witness Dustin Metz addresses the Public Staff's position on the coal unit retirement schedule in his testimony. Regarding coal unit securitization, Duke must comply with Commission Rule R8-74 and HB 951 by securitizing 50% of the remaining net book value of all subcritical coal plants retired early to achieve the carbon reduction goals in HB 951. Specifically, Commission Rule R8-74(b)(8)(a) states that coal plant retirement costs include:

> (f)ifty percent (50%) of the remaining net book value of all of a public utility's subcritical coal-fired electric generating facilities retired early or to be retired early to achieve the authorized carbon reduction goals set forth in Section 1 of House Bill 951 that are appropriate for recovery from existing and future retail customers receiving transmission or distribution service from such public utility.

In addition, the Commission's April 5, 2022 Order Approving Rule R8-74 in Docket No. E-100, Sub 177, states on page 4 that:

> (b)oth the identification of the subcritical coal-fired plants to be retired under the Carbon Plan and the timing of their retirement will be determined in the future. If at that time there are disputes about the correct method for determining the amount of costs eligible for securitization, the Commission will make a determination on a fully developed factual record.

Securitization of the Company's subcritical coal-fired units that are retiring early to meet the carbon reduction goals of HB 951 must be conducted in a timely manner and maximize benefits to customers. The Public Staff will continue to engage with the Companies to ensure compliance with Commission Rule R8-74.

I further recommend that Duke maximize cost savings by assessing whether it would be in the interest of ratepayers to securitize additional coal generation assets, including non-sub-critical coal units.

II. <u>Deferral of project development costs</u>

Q. PLEASE DESCRIBE DUKE'S REQUEST FOR DEFERRAL OF PROJECT DEVELOPMENT COSTS.

A. Duke's Verified Petition for Approval of Carbon Plan requests the Commission determine that Duke is authorized to defer associated project development costs for recovery in a future rate case (including a return on the unamortized balance at the applicable Companies' then-authorized, net-of-tax, weighted-average cost of capital), subject to the Commission's review of the reasonableness and prudence of specific costs incurred in such future proceeding.

Q. PLEASE SUMMARIZE THE PUBLIC STAFF'S POSITION REGARDING THIS REQUEST.

A. As stated in the Public Staff's initial comments submitted in this docket on July 15, 2022, it is premature at this time to authorize any deferrals related to the Carbon Plan. Deferral requests should be handled on a case-by-case basis, include full and detailed costing, including cost breakdowns between operations and maintenance (O&M) and capital costs, and be subject to the two-prong test of extraordinariness and magnitude, or such other criteria that the Commission considers relevant and important at the time.

As of the filing of this testimony, the Companies have been unable to provide a breakdown of estimated costs between O&M and capital costs for the projects for which they are seeking deferral treatment. Furthermore, Duke has an obligation to meet the carbon reduction requirements of Section 110.9 and has not shown how the projects depicted in its request are outside the normal course of business.

The only existing statute that prescribes special ratemaking treatment for project development costs is N.C.G.S. § 62-110.7, which only applies to capital costs (plus allowance for funds used during construction) associated with **nuclear facilities**. While each of the Companies' proposed portfolios contains new nuclear generation (small modular reactors or SMRs) by the year 2050, and three out of the four main portfolios contain new nuclear generation as a means of achieving the interim compliance goal of 70% emission reductions, decisions regarding project development cost deferral for those resources should be made on a case-by-case basis. Initial project development costs for the remaining resources identified in Duke's request for deferral do not meet the specific criteria set out in N.C.G.S. § 62-110.7.

Q. PLEASE ADDRESS DUKE'S TESTIMONY REGARDING A POSSIBLE AFFILIATE TRANSFER OF AN OFFSHORE WIND LEASE IF ITS PROPOSED CARBON PLAN IS APPROVED, AND ANY POTENTIAL COST IMPACT ON RATEPAYERS.

A. In their August 19, 2022 direct testimony, Duke witnesses Repko, Immel, Nolan, and Pompee discuss a potential affiliate transfer of the Carolina Long Bay offshore wind lease from Duke Energy Renewable Wind, LLC to the Companies. They state this transfer may be necessary because the other two entities that currently own wind energy leases that could potentially be used to achieve the emissions reduction targets in the Carbon Plan, Avangrid and TotalEnergies, both of whom are also intervenors in this docket, did not in their comments "indicate a clear desire to sell their [Wind Energy Areas] to the Companies (or to develop a wind generation facility on their WEA and then sell the entire asset to the Companies)."[1] Duke's testimony then states that "absent direct expressions of interest, there is essentially only one option for pursuing development activities for offshore wind at this time."[2]

The need for Duke to begin, at this time, near-term activities to develop offshore wind resources is addressed in the testimony of Public Staff witness Dustin Metz. With respect to the potential affiliate transfer of the Carolina Long Bay offshore wind lease, Duke's testimony provides that the Companies would only seek affiliate approval after the Commission determines that it is reasonable and

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[1] Testimony of Duke Witnesses Repko, Immel, Nolan, and Pompee at 46.

[2] *Id.*

prudent to pursue offshore wind development activities.[3] The Public Staff likewise believes it is premature at this time to make any determination with respect to an affiliate transfer of this offshore wind lease or the potential impact of such a transfer on ratepayers.

III. <u>Whether nuclear development project costs are recoverable pursuant to N.C. Gen. Stat. § 62-110.7</u>

Q. SHOULD RESOURCES OTHER THAN NUCLEAR RESOURCES RECEIVE THE SAME TREATMENT PROVIDED BY N.C.G.S. § 62-110.7?

A. No. As discussed earlier, N.C.G.S. § 62-110.7 applies specifically to nuclear resources and should not be expanded to apply to the other resources included in Duke's deferral request, such as offshore wind and new pumped storage hydro. The Public Staff notes that the General Assembly could have expanded the project development statute to cover technologies other than nuclear facilities, but did not do so when it enacted either N.C.G.S §§ 62-110.7 or 62-110.9.

Q. DOES THE PUBLIC STAFF RECOMMEND APPROVAL OF ANY NUCLEAR PROJECT DEVELOPMENT COSTS AT THIS TIME?

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[3] *Id.* at 47.

A. While SMRs are nuclear facilities, Duke has been unable, as of the date of this testimony, to identify the breakdown of costs between capital costs and O&M costs. Therefore, the Public Staff does not have the information necessary to determine which initial project development costs might be eligible for special treatment under N.C.G.S § 62-110.7 and does not recommend approval of any nuclear project development costs at this time.

IV. Cost recovery of "long lead time resources" ultimately determined not to be necessary to achieve the energy transition and the CO_2 emission reduction targets of HB 951

Q. SHOULD DUKE BE ALLOWED COST RECOVERY OF "LONG LEAD TIME RESOURCES" ULTIMATELY DETERMINED NOT TO BE NECESSARY TO ACHIEVE THE ENERGY TRANSITION AND CO2 EMISSION REDUCTION TARGETS OF HB 951?

A. As stated in the Public Staff's comments, it is premature to authorize any potential recovery of abandoned plant costs related to the Carbon Plan. In its Verified Petition for Approval of Carbon Plan, Duke requests that the Commission make a determination that, "in the event the long lead time resources are ultimately determined not to be necessary to achieve the energy transition and the CO_2 emission reduction targets of HB 951, such project development costs will be recoverable through base rates..."

But prospective authorization to recover abandoned plant costs would remove critical checks on the Companies' spending that have historically helped ensure capital expenditures are reasonable and prudent throughout the life of a project. Requests for recovery of abandoned plant should be handled on a case-by-case basis and held to similar historical standards of treatment of abandoned plant.

The Public Staff recommends that the Commission forbear from determining the ratemaking treatment for such costs until the time a project ceases construction, and that the Commission not pre-determine recovery timeframe, allocation, cost category, or the appropriateness of a return on the unamortized costs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

MICHELLE M. BOSWELL

I graduated from North Carolina State University in 2000 with a Bachelor of Science degree in Accounting. I am a Certified Public Accountant.

As Director of the Accounting Division of the Public Staff, I am responsible for the performance, supervision, and management of the following activities: (1) the examination and analysis of testimony, exhibits, books and records, and other data presented by utilities and other parties under the jurisdiction of the Commission or involved in Commission proceedings; and (2) the preparation and presentation to the Commission of testimony, exhibits, and other documents in those proceedings. I have been employed by the Public Staff since September 2000.

I have performed numerous audits and/or presented testimony and exhibits before the Commission regarding a wide range of electric, natural gas, and water topics. I have performed audits and/or presented testimony in DEC's 2010, 2015, 2017, 2019, and 2020 REPS Cost Recovery Rider proceedings; DEP's 2014, 2015, 2017, 2018, and 2019 REPS Cost Recovery Rider proceedings; the 2014 REPS Cost Recovery Rider proceeding for Dominion North Carolina Power (DNCP); the 2008 REPS Compliance Reports for North Carolina Municipal Power Agency 1, North Carolina Eastern Municipal Power Agency, GreenCo Solutions, Inc., and EnergyUnited Electric Membership Corporation; four recent Piedmont Natural Gas (Piedmont) rate cases; the 2016 rate case of Public Service Company of North Carolina (PSNC); the 2012 and 2019 rate case for Dominion Energy North Carolina (DENC, formerly Dominion North Carolina Power); the 2013, 2017, and 2019 DEP rate cases; the 2017 and 2019 DEC rate cases; the 2018 fuel rider for DENC; several Piedmont, NUI Utilities, Inc. (NUI), and Toccoa annual gas cost reviews; the merger of Piedmont and NUI; and the merger of Piedmont and North Carolina Natural Gas (NCNG).

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

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 divided into the following sections: coal unit securitization; deferral of project development costs; recoverability of nuclear development project costs pursuant to N.C. Gen. Stat. § 62-110.7; and cost recovery of "long lead time resources" ultimately determined not to be necessary to achieve the energy transition and the carbon emission reduction targets of S.L. 2021-165 (HB 951), codified as N.C.G.S. § 62-110.9.

My testimony first discusses coal unit securitization. I state that Duke must comply with Commission Rule R8-74 and HB 951 by securitizing 50% of the remaining net book value of all subcritical coal plants retired early to achieve the carbon reduction goals in HB 951, and must conduct the securitization in a timely manner and maximize benefits to customers. I further recommend that Duke maximize cost savings by assessing whether it would be in the interest of ratepayers to securitize additional coal generation assets, including non-sub-critical coal units.

Next, my testimony discusses the deferral of project development costs. Duke's Verified Petition for Approval of Carbon Plan requests that the Commission determine that Duke is authorized to defer associated project development costs for recovery in a future rate case (including a return on the unamortized balance at the applicable Company's then-authorized, net-of-tax, weighted-average cost of capital), subject to the Commission's review of the reasonableness and prudence of specific costs incurred in such future proceeding. My testimony states that it is premature at this time to authorize any deferrals related to the Carbon Plan. Deferral requests should be handled on a case-by-case basis; include full and detailed costing, including cost breakdowns between operations and maintenance (O&M) and capital costs; and be subject to the two-prong test of extraordinariness and magnitude, or such other criteria that the Commission considers relevant and important at the time.

My testimony then discusses the recoverability of nuclear development project costs pursuant to N.C.G.S. § 62-110.7. While small modular reactors (SMRs) are nuclear facilities and could be eligible for special treatment pursuant to N.C.G.S. § 62-110.7, Duke has so far been unable to identify the breakdown of costs associated with SMR development between capital costs and O&M costs. Therefore, the Public Staff does not have the information necessary to determine which initial project development costs might be eligible for special treatment under N.C.G.S § 62-110.7 and does not recommend approval of any nuclear project development costs at this time. Furthermore, the Public Staff does not believe that resources other than nuclear resources should receive the cost recovery treatment provided by N.C.G.S. § 62-110.7.

Lastly, my testimony addresses cost recovery of “long lead time resources” ultimately determined not to be necessary to achieve the energy transition and the CO_2 emissions reduction targets of HB 951. The Public Staff believes it is premature to authorize any potential recovery of abandoned plant costs related to the Carbon Plan. Prospective authorization to recover abandoned plant costs, as requested by the Companies, would remove critical checks on the Companies’ spending that have historically helped ensure capital expenditures are reasonable and prudent throughout the life of a project. Requests for recovery of abandoned plant should be handled on a case-by-case basis and held to similar historical standards of treatment of abandoned plant. The Public Staff recommends that the Commission forbear from determining the ratemaking treatment for such costs until a project ceases construction, and that the Commission not predetermine the recovery timeframe, allocation, cost category, or appropriateness of a return on the unamortized costs.

This concludes my summary.

MS. LUHR: The Panel is available for Cross-Examination.

CHAIR MITCHELL: All right. Who is up first?

MR. BURNS: John Burns for CCEBA, but I have very few questions that the prior Panel deferred to you.

CROSS-EXAMINATION BY MR. BURNS:

Q.A nd the quick question I have, ma'am, is when -- I think the prior Panel agreed that it would be necessary to develop commercial terms to allow Duke Energy the dispatch of solar and solar plus storage resources that are dispatched that's required in House Bill 951, and my question to you is would you agree that it is important for those terms to fairly compensate operators and owners for the resources that they make available, for the commercial terms? This was deferred to this Panel, wasn't it? I believe it was. If not, I'll ask the next person. I'm sorry. I'm so used to looking across at Jack on that one. So I believe that the prior Panel deferred that question, but I'll -- no? Okay.

MS. LUHR: I don't recall that, but --

MR. BURNS: Okay. I think the issue's covered, but I'll withdraw the question. Thank you. If I was confused, I'm sorry. No further questions.

CHAIR MITCHELL: All right. CIGFUR.

MS. CRESS: Thank you, Chair Mitchell.

CROSS-EXAMINATION BY MS. CRESS:

Q. Good afternoon, Ms. Boswell and Mr. McLawhorn.
Ms. Boswell, does the Public Staff believe this proceeding should be treated as a 62-110.7 proceeding for approval to incur nuclear development costs?

A. We do not.

Q. Thank you. Mr. McLawhorn, in your role as the Director of the Energy Division for the Public Staff, do you evaluate jurisdictional and customer class allocation methodologies and issues?

A. Yes, I do, along with other members of the Energy Division.

Q. Did you hear Ms. Bateman's testimony in response to my cross-examination?

A. I did.

Q. Do you believe there is regulatory risk that the Public Service Commission of South Carolina denies Carbon Plan implementation costs?

A. Okay. I want to understand your question exactly. Are you asking me do I believe that there is a risk that the Public Service Commission of South Carolina might not approve Carbon Plan costs? Is that what you're --

Q. That's correct.

A. Well, there's always a risk in any proceeding in one jurisdiction and a regulatory Commission in another jurisdiction might not allow the same thing.

Q. Would you categorize this specific risk here, in this docket, for this jurisdictional cost allocation issue as minimal, moderate, or substantial?

Q. I really have no way to evaluate that. I mean, I'm not privy to the goings on of the South Carolina Public Service Commission and what their opinions are. I mean, it is a risk, but I don't know how great.

Q. Fair enough. Do you think it would be reasonable to require Duke to model a scenario in which the Public Service Commission of South Carolina denies cost recovery of Carbon Plan costs?

A. It would certainly be one thing to look at. I think if -- you know, if this Commission is concerned about that and would like to know what that -- those modeling results show, then they're certainly welcome to order Duke to do that.

MS. CRESS: Thank you. Nothing further.

CHAIR MITCHELL: All right. CUCA.

MR. SCHAUER: No questions.

CHAIR MITCHELL: All right. Redirect?

MS. LUHR: One question.

REDIRECT-EXAMINATION BY MS. LUHR:

Q. Ms. Boswell, why do you -- why does the Public Staff not think it's appropriate to consider this proceeding this proceeding to be under 62-110.7?

A. Upon our reading of 62-110.7, specifically Subsection B, they are required to request it and provide full details associated with the request. In the present case, although they have -- in my reading, they have not specifically indicated the 62-110.7 request. Additionally, the Public Staff did request some detailed information and the Company was unable to provide such information.

Q. And Ms. Boswell, what kind of detailed information was that?

A. The detailed costing, O&M and capital expenses related to the SMRs.

Q. And is that the type of information the Public Staff would need to determine a cap and a time limit between reviews?

A. Yes.

MS. LUHR: Thank you.

CHAIR MITCHELL: Questions from Commissioners. Commissioner Clodfelter: (Sic)

EXAMINATION BY COMMISSIONER HUGHES:

Q. I think, Mr. McLawhorn, you mentioned in your testimony that you were comfortable -- I forget the exact words, but you were comfortable with the way the PVRR was done, except you were comfortable with the inputs, but you had some questions about whether there was sufficient things added into some of the calculations for all the -- that were common among all the different scenarios. As far as the first part of that question, you were just comfortable with how it was done.

A. Basically how the math was carried out.

Q. Right. And I'm a math guy. That's why I was curious about it. So did you have a chance to actually see that -- because I understand it was done not in the EnCompass but was done in sort of a separate model. Did the Public Staff have an opportunity to actually look at that, I guess, cash flow model or cost benefit, excuse me, a PV analysis?

A. I did not personally evaluate that. Our Modeling Panel, who was Mr. Thomas, who was just the one who -- sorry. To the extent that was looked at, that was him.

Q. Okay.

COMMISSIONER HUGHES: Well, I'll take my questions, I guess, to the next Modeling Panel which happens to be Mr. Snider and friends, so thank you. That's all.

COMMISSIONER DUFFLEY: And actually, I did have one question for Ms. Boswell on page 9 of your testimony.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. So line 6 and 7, that sentence ends that the Public Staff does not recommend approval of any nuclear project development cost at this time. And when you're speaking of that, you're speaking of costs for -- cost recover. And is that -- that's how I read it. And is that different than an approval to engage in the activities themselves?

A. From my perspective, it was cost recovery. I believe Panel 1 discusses approval for -- to participate in any activities related to SMRs.

COMMISSIONER DUFFLEY: Okay. Thank you for that clarification.

CHAIR MITCHELL: Commissioner Kemerait?

(No response)

CHAIR MITCHELL: Okay.

EXAMINATION BY CHAIR MITCHELL:

Q. Mr. McLawhorn, I'm trying to find it. I seem to recall either in Public Staff comments or in your testimony a citation to the Commission's Order directing Public

Staff and the Companies to get to work addressing rate disparity issues between the two operating Companies. Can you update me on the status of that work?

A. Um, we have had some conversations with the Company, but I would not classify them as advanced. Now, I'm not commenting on what the Company may be doing internally, but we've seen -- we've had some preliminary discussions with the Company as to what that might look like, but nothing firm.

Q. Were you able to listen to Ms. Bateman's testimony? And I asked her about the -- my perception of the exigency or the urgency that the Public Staff has conveyed about the disparity and rates and the need to address that. And I think -- I understood her response to be we have some time to do that for the costs associated with the actions we're describing in the Carbon Plan, become passed onto ratepayers. We have some time to think about cost allocation and take additional steps like the other regulatory concepts that the Company has proposed or has discussed in its testimony in this proceeding.

Do you share -- to the extent I had mischaracterized or misunderstood Ms. Bateman's position, and she's going to be up again so she can help us understand if I have, but do you agree there isn't an immediate need to address cost allocation, that we have some time to address that? Or help me understand exactly what you think we need to do and when we need to do it.

A. I think that you have accurately characterized Ms. Bateman's testimony, at least that's how I heard her. That's my recollection. I do not share that view. In my opinion, we need to be about this as soon as possible. First of all, we don't even know if a merger will, in fact, be approved by all jurisdictions and what it might look like. If it does, so if we don't begin addressing the cost allocation issues now, we're just kicking the can down the road and losing valuable time.

And as I've, you know, laid out in my testimony, the rate disparity between DEC and DEP is -- in my opinion, is critical now, and it will only get worse, and we have to find a way to allocate these costs state-wide Carbon Plan. It's not a DEP customer Carbon Plan that DEC customers get to piggyback on. That has to be addressed. And to wait three, four, five years to see what may or may not happen with the merger -- I hope it does turn out to be a full merger.

That's what I think, in my opinion, would be the best outcome, but we may not -- can rely on the best outcome. We need a plan now and we need to start addressing these allocation issues now.

Q. Have you given thought to how that might be done, cost allocation, as we wait for the eventual outcome on any merger or other consolidation proceedings?

A. Well, yes, I have given some thought to it. Some of the issues could and will get into not only legal issues, but potentially what are acceptable accounting issues, and those have to be resolved. I mean, if you just give me a magic wand and let me do it the way an engineer wants to do it, I can make it happen, but that may not be legal or it may not -- it may not meet Ms. Boswell's requirements for accounting practices, so...

Q. Okay.

A. I said I can make it happen. Mr. Metz could make it happen. I scared him when I said that I would do it, but --

Q. Okay. Is there anything that you want the Commission to direct? So let me back up. In my opinion, our Order was clear that we want to do all to get to work. What else could we say to the parties to impress upon them that, you know, this is an issue that they need to start working on?

A. I think possibly put a deadline on it. You want to see something firm by a certain date. Either you're going this way or you're going this way, and here is the path that you're going to take.

Q. Okay. And in seriousness, I mean, is this work that's better taken up in the context of a rate case or is it better to take -- I mean, help me understand. And Ms. Boswell, you weigh in here too because this is going to involve the accountants, but what is the appropriate forum for this work?

A. Let me say, and then I'll pass it over to Ms. Boswell, but I was hopeful that -- and I still am, that it will be addressed in these upcoming DEP and DEC general rate cases. That is the place that it needs to be addressed. Now, I believe the DEP filing is going to occur on October 6th. That's what, about two weeks, three weeks -- two weeks from now. It doesn't necessarily have to be addressed the day of the filing, but, you know, the clock will be ticking starting October 6th, and that is the forum because once we -- assuming we're going to have a Multiyear Rate Plan, the Commission's going to be something rates and using a cost of service that will be in place for the next three years. So if we don't get it done in this case, then we're pushing it out '23, '24 -- maybe '26 before we can -- and all the while, you know, we've got to do these red zone upgrades.

A lot of those are taking place in the DEP territory. We don't have a way to allocate those. I think Ms. Bateman maybe characterized those costs as not that significant, but, you know, to me, anything is significant. And we don't know what the future holds, and I'm going to use my phrase and some people have sort of stolen my thunder because they're going to think that I'm stealing their words, but hope is not a plan. I think it's the third time you've heard that. That's been on my white board for years, so I think somebody sneaked into my office and stole that from me, but anyway, we need a plan, in all seriousness. So I'll let Ms. Boswell come in.

A. (Ms. Boswell) I concur with Mr. McLawhorn. The faster that we get the -- the faster we get together and determine the appropriate allocation, the less the ratepayers, especially in the DEP territory, will be held responsible for costs that they really shouldn't be bearing. And significant to one is entirely different than if I went and knocked on DEP ratepayer's doors and asked them if it was significant to them.

Q. Okay. All right. I'm just making sure I don't have anything else for you-all. Mr. McLawhorn, in your testimony, you also -- you mentioned the comprehensive rate study.

A. Yes.

Q. That work you-all have already undertaken, the Companies have undertaken, and I think you've -- it's generally come to a conclusion, my anticipation is that it will inform, you know, subsequent rate case filings, but give me your thoughts on how that work went and what your expectation is for the time and -- you know, for what's going to come out of the time and the resources you-all expended there.

A. Of course. Mr. Floyd was the primary Public Staff person over that. And my conversations with him and my understanding is that he feels that it went well. That study was primarily to look at ways to make the rate structures between the two utilities more consistent, and that certainly is a step. When I say the "utilities," I mean DEC and DEP, and that's a step that has to be taken. Now, that doesn't have anything to do with the aligning costs but as they would be determined in a rate case, class cost allocation study, jurisdictional. But that is a step that must be taken, and we will expect to see some of the fruits of that when the DEP rate case is filed in a couple weeks.

Q. Okay. Last question for you-all. Mr. McLawhorn, I might direct it to you and then Ms. Boswell, if you want to weigh in, you can. I think you-all -- I think I have seen you-all in this room for most, if not all, of the the hearing so far. Is that correct or have you at least had a -- if you haven't been in here, have you had a chance to listen?

A. (Ms. Boswell) [Nods in the affirmative].

Q. Okay. Have you heard anything of concern that you would like to comment on or that you would like to bring to the Commission's attention? I'm giving you an open-ended question here to let us know if there are things you think we need to be paying attention to.

A. (Mr. McLawhorn) I think one area that I addressed in my testimony that has gotten a little bit of play, but maybe not that much, is the whole concept of least cost, and I address that in one section of my testimony, so I just think -- I would urge the Commission to continue to keep that in mind as you deliberate what the ultimate plan is going to be. Public Staff's interpretation of least cost has never been least bottom line cost. It has always been least or lowest reasonable cost, which considers some of the other factors that our Panel 1 addressed, executability, reliability, and cost to ratepayers.

We all know that the changeover to the electrical system is significant. We have a law. The Public Staff is committed to seeing that carried out, but no one should be deceived into thinking that there's not going to be cost impacts to customers, and that's all classes of customers. And we've always had competitive rates in North Carolina. I've been with the Public Staff for a long time, and I'd like to think that maybe I've had a small part to play in that. And I've always been proud of that, that we've had a robust economy and we've been able to attract good-paying jobs, and I want to see that continue for the entire state, both DEC and DEP, as well as Dominion and all areas. I want the State of North Carolina to be able to flourish into the future, so I'll stop.

A. (Ms. Boswell) I concur with Mr. McLawhorn. As detailed in all of our testimonies, we are just looking for the best path forward knowing that there are going to be costs associated with it and being mindful of the balance between the cost that are being borne by the

Companies and the cost that need to be borne, and the timeliness of those to the ratepayers.

CHAIR MITCHELL: All right. Thank you both. Go ahead.

COMMISSIONER DUFFLEY: Sorry. I have one follow-up question.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. I apologize. I have one follow-up question. Mr. McLawhorn, in your exchange with Chair Mitchell about what the Commission needs to do, you responded set firm deadlines and say we're going down this path or we're going down this path. And I just want to explore that a little bit further. You mentioned that the appropriate forum, no matter which path you take, is the general rate case, but I just want to get some clarification on this path or this path. Do you mean by this date, you need to tell us you're going to merge the Companies and we want this merger to happen before the rate case, are you saying, or the other option is that you're going to have a workable method to properly and appropriately allocate the cost between DEC and DEP to achieve the Carbon Plan?

A. Okay. I think I'll have to take that in part. So we need a workable and reasonable way to allocate the cost between DEC and DEP, and we need to be able to do that before rates are set in these upcoming rate cases. That needs to be done regardless of whether there's a merger or not, in my opinion. I think that's where Ms. Bateman and I have some disagreement. She is focused on the merger and let's go down that path and not worry about the cost allocation issue now, because once we merge, that will take care of itself.

And I don't disagree with her that once we merge, then we'll just have one utility and we'll have one big pot of costs, but I am concerned -- we can't possibly merge by the time of the rate case or even by the end of the rate case because I think the plan that Ms. Bateman and Mr. Peeler laid out in their joint testimony I think had the merger maybe -- I think it was around 2026, and I said I thought that was a reasonable timeline. I have no idea whether that will truly be possible or not. I mean, I looked at it and the steps that they had identified, and I said well, that's reasonable, but it could take longer than that. I doubt seriously it would take less time than that.

And Duke will be incurring costs, and I believe significant costs before then, so we need to get the cost allocation issue, some type of mechanism for that before rates are set in these upcoming rate cases. Did that --

COMMISSIONER DUFFLEY: That answered my question. Thank you.

CHAIR MITCHELL: All right. Questions on Commission's questions. Go ahead.

EXAMINATION BY MS. CRESS:

Q. Mr. McLawhorn, Ms. Boswell, have either of you evaluated DEP's recent filing listing transmission projects in Docket No. E-2, Sub 1300?

A. (Mr. McLawhorn) I have looked at it. I can't talk about it with any detail.

Q. Would you agree that that docket was opened for the purpose of deciding DEP's first performance-based regulation rate case in North Carolina?

A. Yes.

Q. And it's true, is it not, that DEP is seeking to include certain costs for some RZEP projects for recovery in the Multiyear Rate Plan, that it will seek to have the Commission approved in that docket. Is that right?

A. Yes. That's my understanding.

Q. And those costs will be allocated according to a transmission allocation factor pursuant to the

jurisdictional and customer class allocation methodologies approved by the Commission in that rate case?
A. Yes.
MS. CRESS: Thank you. No further questions.
CHAIR MITCHELL: Questions from Duke?
MR. JIRAK: Yes, just a few.
CHAIR MITCHELL: Okay.
EXAMINATION BY MR. JIRAK:
Q. So I just want to follow up on a couple of questions from the Commission on the merger and the steps that the Companies and the Public Staff have been discussing with respect to addressing cost differences. So I think you would agree that the merger is the most direct and simplest way to deal with the forward-looking cost differences, correct?
A. (Mr. McLawhorn) That's the way I see it, yes.
Q. Okay. And obviously, you're aware the Companies have identified that as their -- as also as their preferred and most direct route to solving these issues, correct?
A. Yes.
Q. And the Companies have, in fact, put forward a timeline for achieving that merger, and I think you referenced that just a moment ago, and I'm assuming you're

familiar with that timeline?
A. Yes. And I said that I thought it was reasonable.
Q. Okay. And so under that timeline, the Companies would be achieving -- have targeted achievement of a -- completion of a merger, consummation of a merger by the beginning of 2027?
A. Yes.
Q. Okay. And understanding there will be hurdles to be cleared to achieve that, if that happens from that point forward, "we'll have a solution" quote unquote for the rate difference for new investments going forward.
A. For new investments going forward yes, but not for the ones that will occur between now and then.
Q. Okay.
A. And that's if the merger, in fact, is consummated in time by 2027.
Q. Understood. And I'm assuming you've had a chance to review Ms. Bateman's testimony on rebuttal.
A. I did, yes.
Q. And do you happen to have a copy of it with you? We can provide one, I think, if you don't have one.
A. Yes, I do.
Q. Okay. Let me just paraphrase a part of what you said,

and we can take you to the page if we need to, but do you recall that her -- her testimony is that the Carbon Plan investments themselves are not materially or in most cases, are all widening the rate differential through 2026, and she provided some analysis behind that statement. Do you recall that portion of testimony?

A. I generally recall it. Can you direct you me?

Q. Yes, certainly. Page 6 of her rebuttal testimony. And the question starts on line 1. And sort of the heart of that statement is beginning on line 21. It's page 6 line 21.

A. Yes. I see that, and I recall that that's her testimony.

Q. Okay. And do you take any issue with the calculations that Ms. Bateman has provided there?

A. No, not necessarily, but I also know that may not be the way the costs work out exactly either, so...

Q. Okay. But you understand that her position is that based on her calculations, the Carbon Plan investments themselves don't actually contribute to further widening under -- most of these circumstances or any material amount of widening before the point in time at which the merger is targeted for consummation.

A. I understand that that's her testimony. I don't necessarily agree with that. I'm not taking issue with her calculation here, but I don't necessarily agree with her conclusion.
Q. Okay. And I appreciate that. Let me ask you a hypothetical and I'll wrap up. So if Ms. Bateman's correct and the Carbon Plan doesn't drive any material widening of rate differences before the targeted time for completion of merger, would you agree that would lessen the need to identify other alternative options for addressing rate differences that will be immediately not needed as soon as you have the merger in place?
A. I guess I would go back to my testimony that it is not a guarantee that the merger will take place. And I'm not, in any way, implying that Duke would not be earnestly pursuing the merger, but you have to -- as I said earlier, you have to get approval, not only from this Commission but from the South Carolina Public Service Commission, as well as to FERC, and it will require approval from all three of those. And we don't know if you'll be able to get that. I hope you do. I know you hope you do, but we don't know that. And if we wait until 2026 or 2027 and find out you were at the

last step and you've been turned down, then we're starting to get into more significant costs. I'm not going to say that I don't think the costs are significant between now and then, but they will certainly become more significant, and then we're having to start from scratch at that point.

Q. But you would agree that when and if -- if and when those more material rate differences start to develop post 2027 or post the end of 2026, looking into 2027, those would be subject to consideration of rate cases in which the Commission would have additional opportunity to consider those, resolving those issues?

A. Yes. And we don't know when that next rate case might be at that point in time. It could be -- you could have just had one, and it could be three more years, and so we might be looking at 2030.

Q. Okay.

A. But we don't know. So as I said, we need a plan now.

A. (Ms. Boswell) And I would just like to add keep in my any plan that you add between the rate cases would still be allocated at the previous rate case level. So if, for whatever reason, you didn't come back in at that point in time, those new costs would still be allocated at that old level, which presents a problem.

Q. But not reflected in rates if there was not a -- in-term rate case, they wouldn't be reflected, right?
A. Well rates are determined -- rates are supposed to be reflective of serving all of the customers based off of whatever it is that you put into service.

MR. JIRAK: Okay. No further questions.

CHAIR MITCHELL: Public Staff.

MS. EDMONDSON: Just a couple of questions.

EXAMINATION BY MS. EDMONDSON:

Q. Mr. McLawhorn and Ms. Boswell, the Commission had told the Public Staff and Duke to get busy on working on the rate disparity issue. To address this, would the Public Staff consider making an adjustment to account for this allocation issue in the upcoming rate case?
A. (Mr. McLawhorn) That's possible. I believe I mentioned that in my testimony.
Q. And Chair also asked about the ways the Commission could address this rate disparity. Is it your understanding of the performance-based ratemaking, could the Commission disallow any recovery of cost that should be allocated in this upcoming Multiyear Rate Plan?
A. I believe the Commission has the discretion to disallow any cost they find are not reasonable.

Q. And is it your understanding under the performance-based ratemaking statute that the Commission could even deny the Multiyear Rate Plan --
A. I'll let Ms. Boswell answer.
Q. -- and still go forward with the general rate case?
A. (Ms. Boswell) That is my understanding.

MS. EDMONDSON: Okay. Thank you.

CHAIR MITCHELL: All right. At this point, I think we are -- there's nothing further for this Panel. I'll entertain motions, if necessary.

MS. LUHR: Chair Mitchell, the Public Staff would move that the testimony summaries of Michelle Boswell and James McLawhorn be moved into the record.

CHAIR MITCHELL: All right. They will be copied into the record at the appropriate time. Any additional motions for these witnesses?

(No response)

CHAIR MITCHELL: All right. You-all may step down. Thank you very much for your testimony today, and you are excused. We're going to take a break for the court reporter for five minutes. We're off the record. We'll be back on the record at 3:37.

(Whereupon, a break was taken)

CHAIR MITCHELL: Let's go back on the record, please. Let's get these witnesses sworn.

REBECCA GALLAGHER;
MICHAEL STARRETT;
having been duly sworn,
testified as follows:

MR. SMITH: All right. Thank you. My name is Ben Smith representing Avangrid Renewables, and I'm going to go ahead and get started. This is the Avangrid Renewables Panel that just got called and sworn in.

DIRECT-EXAMINATION BY MR. SMITH:

Q. Ms. Gallagher, would you please state your full name and business address for the record.

A. My name is Rebecca Gallagher. I go by Becky. The Offshore Wind business address for Avangrid Renewables, LLC is 125 High Street, 6th floor, Boston, Massachusetts 02110.

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

A. I'm employed by Avangrid, and my role is Director of the New Business Team for Offshore Wind.

Q. Thank you, Ms. Gallagher. Can you please briefly describe your role and responsibilities with Avangrid Renewables.

A. Sure. The New Business Team focuses on the non-engineering scope of early stage business development for Offshore Wind. This covers market-making and basically all forms throughout the eastern seaboard, and California as well. Working with state policy makers and The Bureau of Offshore Energy Management and wind policy and lease proceedings. BOEM auction, preparation, and execution. Stakeholder work or of peer responses; contract negotiation, partnerships, mergers, and acquisitions.

Q. And just to clarify, I think you said Bureau of Offshore Energy Management? Did you mean Offshore -- I'm sorry, Ocean Energy Management?

A. I did. Thank you. Doctor Starrett, I'd like to turn to you. Would you please state your full name and business address for the record.

A. Yeah. My name is Michael Starrett, and the Offshore Wind business address for Avangrid Renewables is 125 High Street, 6th floor, Boston.

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

A. My position at Avangrid Renewables is Senior Manager of the Bid and Valuing Engineering Department.

Q. And Doctor Starrett, can you please briefly describe your role and responsibilities of the Avangrid Renewables.

A. Yeah. At Avangrid Renewables, the department that I'm responsible for is -- the department I lead is responsible for the business case and overall commercial execution of our contracted portfolio. So in total, across the U.S., that's about one-sixth of everything that's under contract. My team and I are closely involved in the engineering, the contracting, the procurement of the full scope of equipment and services that are needed to construct and operate large-scale Offshore Wind projects benefitting from the deep understanding that we have on the project fundamentals and the value drivers earned through our overseeing of the business case, these projects. My team is continuously involved in our organic and inorganic growth, that through lease auctions, and RPs, and mergers and acquisitions.

Q. Thank you. And Doctor Starrett, since you agreed to be lead witness for this Panel, I'm going to ask you, did the Panel cause to be prefiled in this docket direct testimony consisting of 25 pages?

A. Yes.

Q. Do you have any changes you need to make to your Panel's direct testimony at this point in time?

A. Yeah. I wanted to clarify for the Commission a point on the $850 million dollar CAPEX equivalency that we described in our direct testimony. Duke claimed during its Long-lead direct testimony that this was a miscalculation. But in fact, it was correct, and we want to add a clarifying remark. We stated in our direct testimony on page 23 line 5, quote, "Put in terms of CAPEX, based on the simple but reasonable financial equivalence of about 50 million per percent change in NC" --

MS. LINK: Chair Mitchell, not to interrupt, but if this is -- it sounds like it's surrebuttal, but if it's additional language to add to your testimony, could we possibly go a bit slower so we could write it down.

MR. SMITH: I'd object to this being characterized as surrebuttal. This is responding to some question about whether Avangrid Renewables had done correct math in their direct testimony, but I will instruct my witnesses to slow down.

MS. LINK: That's just the nature of surrebuttal, but...

CHAIR MITCHELL: So Mr. Smith, you don't have an opportunity to engage in direct-examination here with your witness. You know, you may have an opportunity to engage with him on redirect.

MR. SMITH: Sure.

CHAIR MITCHELL: So let's -- unless there are corrections that need to be noted for purposes of the record, let's move forward.

BY MR. SMITH:

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

A. Yes.

Q. And did you also cause to be prefiled in Docket 179-A a summary of your direct testimony?

A. Yes.

Q. And is the testimony set forth in your summary true and accurate, to the best of your knowledge?

A. Yes.

MR. SMITH: Chair Mitchell, at this time, I would ask that the direct testimony and summary of Ms. Becky Gallagher and Doctor Michael Starrett be entered into the record as if given orally from the stand.

CHAIR MITCHELL: All right. Motion's allowed.

(WHEREUPON, the prefiled direct testimony and summary of MICHAEL STARRETT and BECKY GALLAGHER are copied into the record as if given orally from the witness stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 179

In the Matter of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan	)))))))	**DIRECT TESTIMONY OF MICHAEL STARRETT AND BECKY GALLAGHER FOR AVANGRID RENEWABLES, LLC**

I. INTRODUCTION

Q. DR STARRETT, PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION AT AVANGRID RENEWABLES.

A. My name is Michael Starrett and the Offshore Wind Business Address for Avangrid Renewables, LLC ("Avangrid Renewables") is 125 High St., 6th Floor, Boston MA 02111. My position at Avangrid Renewables is Senior Manager of Bid and Value Engineering.

Q. DR. STARRETT, PLEASE BRIEFLY STATE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I received a Bachelor and Master of Science in Engineering in 2008 and 2010, respectively, from Michigan Technological University. I later received a Ph.D. in Electrical Engineering in 2016 from Oregon State University.

Prior to joining Avangrid Renewables, I worked at the Northwest Power and Conservation Council in Portland, OR where I was responsible for transmission, renewable energy, and emerging technology. I worked closely with policy makers, utilities, public utility commissioners and commission staff, and other stakeholders in a process very similar to a utility IRP. I have a deep understanding of capacity expansion and production cost models as well as real time physical grid operations from this experience.

Additionally, I worked as an adjunct faculty member in the Electrical Engineering department at Oregon State University teaching electric machines and drives. I also was a long-term guest lecturer in their School of Public Policy, lecturing in US energy policy.

Q. DR. STARRETT, WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT ROLE?

A. At Avangrid Renewables, I lead the department responsible for the business case and overall commercial execution of our contracted portfolio. In total, this is roughly one-sixth of the entire total offshore wind capacity under contract in the United States.

My team and I are closely involved in the engineering, contracting, and procurement of the full scope of equipment and services needed to construct and operate large scale offshore wind projects.

Additionally, taking advantage of the deep understanding of project fundamentals and value drivers earned through overseeing the business case for these projects, my team is continuously involved in our organic and inorganic growth through lease area auctions, requests for proposals, and mergers and acquisitions.

Q. DR. STARRETT, ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Avangrid Renewables, an intervenor in this proceeding.

Q. DR. STARRETT, HAVE YOU PREVIOUSLY TESTIFIED IN FRONT OF THE NORTH CAROLINA UTILITIES COMMISSION?

A. No.

Q. MS. GALLAGHER, PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION AT AVANGRID RENEWABLES.

A. My name is Becky Gallagher and Avangrid Renewables' Offshore Wind Business Address is 125 High St., 6th Floor, Boston MA 02111. My position at Avangrid Renewables is Director of Offshore Wind New Business.

Q. MS. GALLAGHER, PLEASE BRIEFLY STATE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I received dual Bachelor of Science degrees from Tufts University, in Environmental Studies and International Relations, in 2010. I later received dual Master's degrees in 2016: a Master of Business Administration from the Yale School of Management, and Master of Environmental Management from the Yale School of the Environment.

Following Yale, I worked in renewable energy project finance for the SunPower Corporation, where as an analyst I developed solar project business cases, researched market rules, responded to RFPs, and ran financial models to set pricing on behalf of the company. Eventually I managed that same group, overseeing financial modeling for public projects east of California as well as all national accounts. In addition, I ran east coast partnerships discussions, represented the company in PPA contract negotiations, and managed the pipeline for public projects nationwide.

At Avangrid Renewables, I have managed financial modeling and pricing for our Investment Office's east portfolio, including all offshore wind project financial modeling. This included modeling financials for the company's offshore wind offtake bids into Massachusetts and New York. My prior team was also responsible for taking projects to Final Investment Decision, which is required to unlock construction spending for a project.

Q. MS. GALLAGHER, WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT ROLE?

A. About a year ago, I moved internally from the Investment Office to the New Business team. The New Business team focuses on the non-engineering scope of all early-stage business development. This covers market-making in all forms, such as working with state policymakers and the Bureau of Ocean Energy Management ("BOEM") in offshore wind policy and lease proceedings, BOEM auction preparation and execution, stakeholder work, RFP responses, contract negotiation, partnerships, mergers, and acquisitions.

Q. MS. GALLAGHER, ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Avangrid Renewables, an intervenor in this proceeding.

Q. MS. GALLAGHER, HAVE YOU PREVIOUSLY TESTIFIED IN FRONT OF THE NORTH CAROLINA UTILITIES COMMISSION?

A. No.

II. SUMMARY

Q. MS. GALLAGHER, PLEASE SUMMARIZE THE PANEL'S TESTIMONY.

A. The purpose of our testimony is to address the "Near-Term Development Activity—prudence of development work and need for long-lead time resources" topic, as stated in the Issues Report, particularly with regard to the development of the Kitty Hawk lease area into an offshore wind facility. In some areas, our testimony relates to and overlaps with other topics, specifically "Modeling—Methodology, assumptions and other modeling issues" and "Transmission Planning, Proactive Transmission, and RZEP." Where this occurs, we make mention in our response.

Two themes are common throughout our testimony – first, the importance of offshore wind to meeting the state's urgent and critical carbon reduction goals of 70% reduction by 2030 and the resources available to do so. The Kitty Hawk lease area is the only offshore wind lease area that can reasonably bring power to North Carolina by 2030 – but it cannot do so without a near term commitment from Duke. Avangrid Renewables recommends immediate action on offshore wind, first in the form of an independent evaluation of the available lease areas, and then by prioritizing the most mature, least cost area to progress, taking all reasonable steps necessary to cause one or more projects from that lease area to achieve the earliest possible Commercial Operation Date ("COD") in compliance with the HB 951 goals.

The second theme of our testimony is the need for the Commission to take an objective, arms-length approach to offshore wind development. Only then can it select the best possible path forward for ratepayers. To date, Duke's and other intervenors' Carbon Plan modeling does not reflect the material differences between the offshore wind lease areas. Duke's direct testimony indicates their preference to advance Duke Renewables LLC's OCS-A 0546 lease area first. But this lease area has a weaker profile than the Kitty Hawk lease area on four key metrics that would directly impact ratepayers: wind speed, capacity, schedule, and risk. Offshore wind requires a major commitment of time, resources, and money. We urge the Commission to take time upfront to evaluate the available lease options on their merits with support of a third-party study and to ensure that based on those results, Duke pursues the best possible deal for ratepayers.

What follows is a high-level overview of the benefits of offshore wind, near-term alternatives, a discussion of the supplemental modeling portfolios, and the differences between the regional lease areas in terms of schedule, engineering inputs, and overall risk profile. In general, Dr. Starrett will cover technical and engineering topics while I will cover our view on a potential transaction and our recommendations to the Commission.

III. DISCUSSION

Q. DR. STARRETT, PLEASE DESCRIBE THE IMPORTANCE OF THE OFFSHORE WIND ASSET CLASS WITH REGARD TO MEETING THE STATE'S CARBON REDUCTION GOALS AS STATED IN HB 951.

A. Avangrid Renewables agrees with Duke's testimony that offshore wind has many benefits to ratepayers and the environment. These benefits include carbon emissions reductions, fuel cost savings, and significant diversity benefits as solar continues to proliferate in the region. We believe that at least 1.3 GW of offshore wind can deliver these benefits and serve as a cornerstone to meeting the 70% reduction target required by HB 951 by 2030, with more offshore wind capacity available to follow thereafter.

There are more than 55 GW of offshore wind in operation globally – 21 GW of which came online in 2021 alone – and more than 17 GW under contract and working towards operation in the US. This level of deployment has moved offshore wind well beyond its early days, into a young but proven technology with a domestic track record on all critical development milestones, from lease area acquisition to start of construction, and a wealth of construction and operational data from European projects.

Offshore wind's demonstrated constructability, proven operations, large size, and high-capacity factor provide an important hedge in any utility portfolio which includes untested technology facing cost and timeline risk (such as new nuclear and hydrogen), unprecedented amounts of a single technology (such as solar), and planned retirements of existing capacity critical to system reliability.

Offshore wind also has a significant generation shape diversity benefit, likely well above what has been modeled and presented to the Commission in this proceeding thus far. The yearly resource additions in Duke's Carbon Plan proposal reflect a system which is increasingly short on capacity as thermal plants retire, and battery storage along with relatively low effective load carrying capability (or ELCC) solar are the primary resources selected to fill the gap. On paper, this satisfies the production cost model used by Duke, but it could create real world operational challenges when forecast uncertainty and extreme weather materialize at intra-hour timescales not adequately captured within the modeling tools.

In contrast, offshore wind produces consistently throughout the day, providing a baseload-style curve that produces roughly equally at all hours in winter when solar is at its seasonal low, and at a gentle inverse of the solar daily load curve in summer as the images below from the Southeastern Wind Coalition show. Offshore wind also produces, at its nameplate capacity, more hours per year, with NREL reporting capacity factors in the 40 percent range, versus high 20s and low 30s for solar.

FIGURE 1

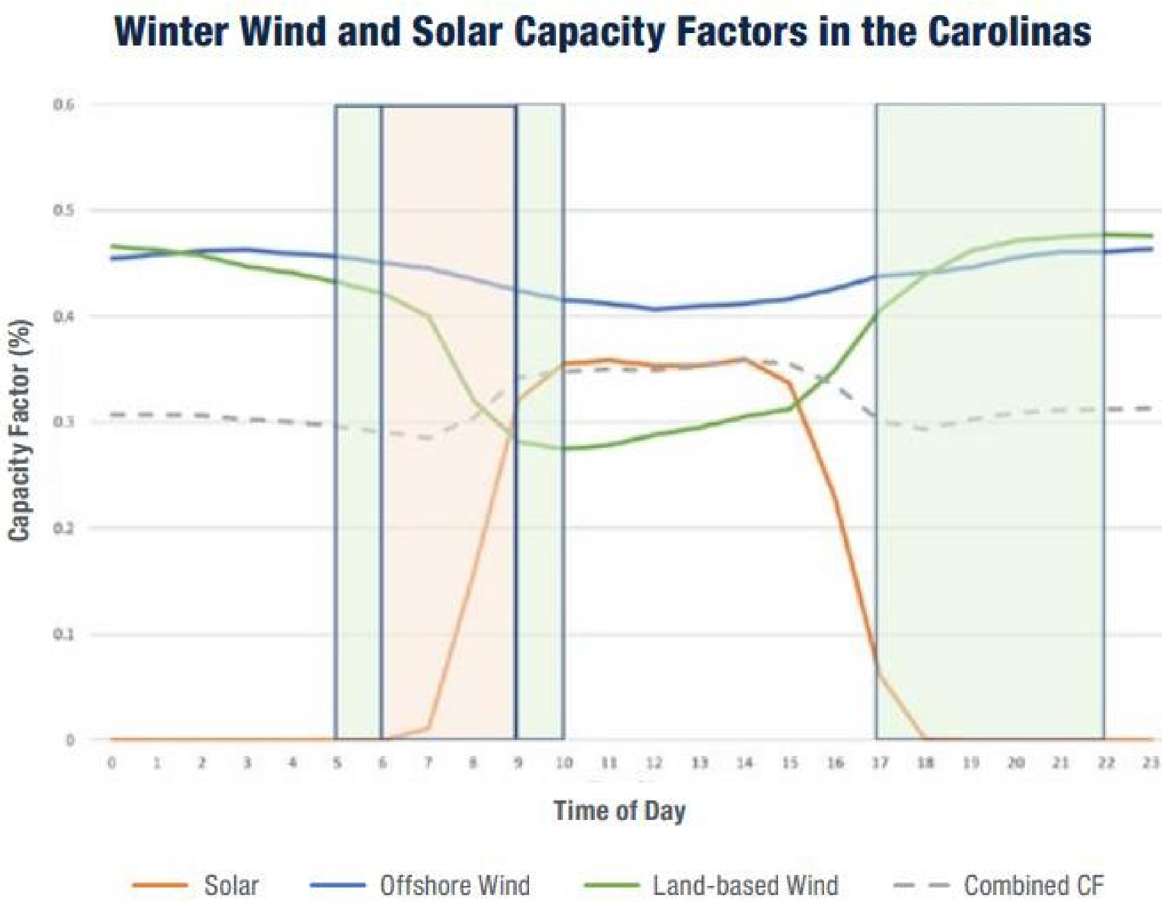
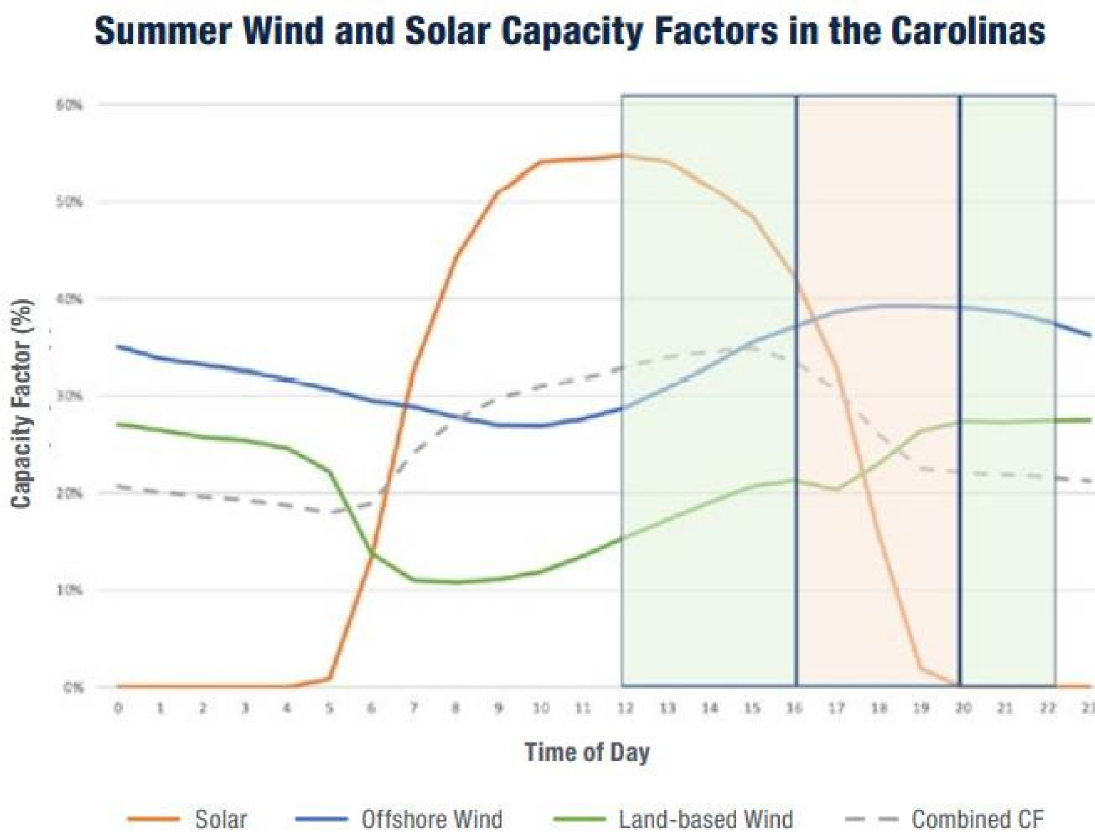


FIGURE 2



While any type of generation project can run into supply chain issues, offshore wind is unique to solar and presents a potential diversity benefit in that area. Offshore wind has a different supply chain than other renewables, particularly solar and solar-plus-storage technologies, lowering the state's exposure to certain risks that would come from an over-concentration in a single component or geography. Offshore wind's costs and schedule are independent of the polysilicon, monocrystalline and cobalt markets that make up so much of the solar and storage capital expenditures (or CapEx). Instead, offshore wind is exposed to inputs like steel, labor, and manufacturing slot availability. Furthermore, as we have all learned over the past few years, no commodity or geography is safe from major disruption, whether from inflation, labor and ethics disputes, or tariff changes. These disruptions can have major impacts on U.S. buildouts, but the state's carbon reduction goals cannot afford to wait them out. That's why supply chain and commodity diversity is so critical to HB 951's successful implementation.

Finally, offshore wind can be delivered even without the costly 500kV grid expansion considered in Duke's Carbon Plan proposal. Duke's proposal burdens the first offshore wind projects with this nearly 1 billion-dollar cost, implying it is a requirement for success. We disagree. We appreciate that a major grid expansion could support large amounts of new clean energy, and that the Commission may want to consider such an expansion as part of a long-term vision. But it is not an absolute requirement for early offshore wind projects, and it is an unreasonable burden to place on these resources in the model. A first offshore wind project, with grid upgrades sized to the project at hand, unlocks the 70% reduction by 2030 more cost-effectively.

Q. DR. STARRETT, WHY IS IMMEDIATE ACTION ON OFFSHORE WIND NECESSARY IF THE SUPPLEMENTAL MODELING FINDINGS DO NOT INCORPORATE OFFSHORE WIND UNTIL 2040? AND WHAT ISSUES OTHER THAN NEAR-TERM DEVELOPMENT ACTIVITY FROM THE ISSUES REPORT DOES THIS QUESTION AND ANSWER ADDRESS?

A. This question and answer is not only relevant to the "Near-Term Development Activity—prudence of development work and need for long-lead time resources" issue, but also the "Modeling— Methodology, assumptions and other modeling issues" and "Transmission Planning, Proactive Transmission, and RZEP" issues.

We agree with Duke that the supplemental filings do not mitigate the need to urgently pursue offshore wind in the near term. Duke's modeling in portfolios P1-P4 and SP5-SP6 collectively affirm that early offshore wind is the only path to achieve a 70% reduction by 2030. Only portfolio P1, which is one of only two portfolios to add offshore wind before 2030, achieves this target date. Had Duke not arbitrarily modeled offshore wind in inefficient 800 MW blocks or artificially limited capacity increases to a single 800 MW block per year, it is possible that portfolio P2, which adds a second 800 MW tranche of offshore wind in 2031, may have also achieved the interim reductions target earlier by deploying a larger project by 2030.

Of note, Duke articulates the 500kV grid expansion as a justification for this staged build out. We expressed our disagreement with this requirement earlier, but I want to offer a bit more detail here. In Duke's transmission-related testimony, Ms. Farver cited the 2020 North Carolina Transmission Planning Collaborative (NCTPC) Offshore Wind Study. Within that very study, the Havelock 230 kV Point of Interconnection is shown to be able to support more than 1 GW at $0.07/W and the New Bern 230 kV Point of Interconnection is shown to be able to support more than 1.7 GW at $0.14/W, all without the 500kV expansion. In our own diligence – which included steady state and dynamic analysis similar to a formal interconnection study – we confirmed that cost effective injections around 1.3 GW are possible in Havelock/New Bern without the 500kV upgrade.

If Duke begins in earnest with a site that is already well-progressed in federal permitting, offshore wind can deliver at least 1.3 GW by 2030 and achieve the 70% reduction target on the timeline set by HB 951.

Q. MS. GALLAGHER, DO YOU AGREE WITH DUKE'S PROPOSED NEAR-TERM ACTION AS IT RELATES TO OFFSHORE WIND?

A. While we agree that near-term action to advance offshore wind is critical, we fail to see how Duke's proposed near-term action to purchase Duke Renewables' OCS-A 0546 lease area adds value for or protects ratepayers. First, Duke has failed to provide any cost/benefit review of what they propose to acquire, for example:

- expected total nameplate capacity in the zone based on engineering,
- likely net capacity factors based on nearby meteorological towers,
- how viewshed risk may impact the size and value of their acquisition,
- what a project from this area will cost beyond a generic estimation, and
- how each of these fundamental value drivers compare to other lease areas available to deliver to North Carolina.

The answers to these critical but as-yet unexplored questions will affect whether ratepayers are being delivered the optimal solution under HB 951.

Just as importantly, Duke's understanding of the projects' critical path to get OCS-A 0546 online is confused. In Duke's testimony regarding long lead resources, Mr. Repko stated that Duke considers the key near-term offshore wind development activity to be "(1) secure an ownership interest in a lease ...(2) initiate and develop permitting activities which will consist of (a) developing and submitting a SAP [Site

Assessment Plan]... (b) developing a COP [Construction and Operations Plan] ... and (3) obtaining approval of a SAP from the Bureau of Ocean Energy Management ("BOEM")".

This seems to suggest that an acquisition unlocks progress on an SAP and COP. But there is no requirement for Duke Energy Renewables to convey OCS-A 0546 to Duke prior to progressing on the SAP and COP. The SAP and COP must be progressed in any case to satisfy federally mandated timelines of no later than twelve months from lease issuance ("preliminary term") and five years from BOEM approval of an SAP ("site assessment term"), respectively. Neither of these timelines, nor any other outside rule, requires site owners to execute a commercial agreement in order to maintain their claim to the leasehold. Conversely, nonconformance to BOEM lease conditions - such as a failing to adhere to prescribed timelines - results in lease forfeiture. So regardless of action by Duke, the OCS-A 0546 lease area owners must progress their SAPs and COPs on a timeline pursuant to 30 CFR 585 or risk lease forfeiture.

After COP approval, there are additional federal permits that lease owners must acquire beyond the COP, but the majority of development spend is during the preparation of the COP. Kitty Hawk, unlike the Carolina Long Bay (CLB) lease areas (including OCS-A 0546), has already cleared these major federal permitting hurdles.

Duke's acquisition of OCS-A 0546 has unclear benefit to ratepayers considering the relative value proposition of Kitty Hawk, and such acquisition in the order proscribed by Duke would neither impact on the obligations of the current site owner to progress the zone, nor change the permitting or COD timeline for that lease area.

Q: MS. GALLAGHER, PLEASE COMMENT ON THE FUTURE PROSPECTS FOR THE KITTY HAWK LEASE AREA AND WHETHER AVANGRID RENEWABLES WOULD CONSIDER SELLING THE KITTY HAWK LEASE AREA.

A: Avangrid Renewables is open to any manner of transaction that is on reasonable terms and fairly values the Kitty Hawk lease area, including PPA transactions, or a sale of the lease area, in whole or in part. Avangrid Renewables would also consider entering into service contracts for development, construction, and/or operations and maintenance of the asset. Avangrid Renewables expects to present its position on the legality of third-party ownership in a separate brief to be filed with this Commission on September 9, 2022 in the non-hearing track. Avangrid Renewables believes the Kitty Hawk lease area should serve the residents of North Carolina, either directly or post-conveyance, and does not see the language of HB 951 as a barrier to do so.

Q. MS. GALLAGHER, PLEASE EXPLAIN WHY PRIORITIZATION BETWEEN AVAILABLE OFFSHORE WIND RESOURCES IS IMPORTANT.

A. Unique project characteristics like resource quality, local considerations, and site-specific schedule constraints determine a given energy project's value and ultimate success. As a result, each project holds a different implication for investors or ratepayers. Resources like solar energy have hundreds of projects in the pipeline – 484 of the 497 active entries as of August 29, 2022, according to the Duke North Carolina queue webpage. For this asset class, no single project "makes the market." That allows modelers to use average or typical values across the asset class. But in the case of offshore wind, individual projects are so large and capital intensive, and the options are so few that it warrants an individual analysis of the available options.

The three lease areas - Kitty Hawk and the two CLB areas – have materially different Net Capacity Factors, Commercial Operation Dates, and overall risk profiles, none of which are captured by the Duke modeling or testimony. Pages 14-18 of our previously submitted Limited Comments highlight these key differences.

Where HB 951 provides a competitive mechanism to choose the best solar projects, no such control exists for offshore wind, and it is the role of the Commission to represent the competitive market on the behalf of ratepayers. We recommend that the Commission take action to distinguish between the few unique options on the market and compel Duke to prioritize development of the most promising ones.

An arms-length assessment of the options is especially important in the case of the Carbon Plan proceeding, as a Duke Energy subsidiary holds one of the three lease areas - Duke Renewables LLC's project OCS-A 0546. Our concluding section describes a proposal to maintain all of the benefits of pace and optionality, and to ensure that ratepayers are well-protected through competition.

Q. DR. STARRETT, WHAT IS THE STATUS OF BOEM PERMITTING SPEED AND QUEUE, AND WHAT IS THE MARKET STANDARD FOR WHEN A PROJECT CAN BEGIN CONSTRUCTION?

A. There are 16 projects awaiting a Record of Decision ("ROD") from BOEM – all of which are ahead of both CLB lease areas in development maturity. No project can be built without first obtaining this approval along with several other federal permits. BOEM does not process the permit submissions in a strictly chronological order; it also considers project readiness and how soon the project can provide supplemental data. On both fronts, the CLB lease areas will struggle to advance their position versus other projects.

The speed with which an offshore project can progress depends on a few factors. First, the experience and staff level of the developer determines how quickly it can move through the very complex federal permitting regime. As Ms. Gallagher mentioned, the SAP and COP are, respectively, on one- and five-year federally mandated timelines with only two offshore wind RODs (which follow the SAP and COP) issued to-date. Although the present administration has dedicated more resources towards expediting the process, the BOEM backlog for SAP and COP processing has grown significantly over the last few years since Vineyard Wind 1, which is 50% owned by Avangrid Renewables, became the first project to go through the process (receiving all federal permits in 2021).

Permitting has a significant impact on construction schedules and a project's COD. Most project developers find it prudent to significantly advance permitting before commencing spend on large packages. The most striking example of this concept is the High Voltage Direct Current ("HVDC") transmission package, which can cost about $1 billion. The HVDC system requires Limited Notice to Proceed about five years before COD because the design, engineering and limited slot availability demands extremely early action. Even if the CLB areas achieve ROD as soon as possible– 2027, as Duke claimed in the Carbon Plan – this would still be too late to allow for a prudent spend schedule and meet a 2030 COD because it would force Duke (and ratepayers) to commit to approximately $1 billion of procurement spend before receipt of the critical federal permit.

Q. DR. STARRETT, AVANGRID RENEWABLES CLAIMS THAT KITTY HAWK IS ON A SHORTER TIMELINE TO COD THAN THE CAROLINA LONG BAY LEASE AREAS. WHAT IS THE RATIONALE FOR THAT CLAIM?

A. In Direct Testimony, Duke claims that the CLB lease areas could reach COD by 2030 by quoting Avangrid Renewables' Limited Comments that projects take 8-10 years from lease acquisition to COD. The sum of permitting durations can indeed be as short as eight to ten years. In fact, Avangrid Renewables' Vineyard Wind 1 project, the first commercial scale offshore wind project in the country, is set to achieve this timeline, having acquired its lease in 2015 and now on track to reach commercial operations in 2024. However, the Commission must assess the feasibility of each project's COD timeline on its own merits.

All else being equal, more mature projects have lower risk on schedule, cost, and local opposition. Avangrid Renewables purchased the Kitty Hawk lease area in 2017 and has been developing it ever since. The team, staffed with local developers and supported by a full back-office in Boston, has submitted the lease's SAP, held dozens of stakeholder meetings, submitted two COPs covering the entire zone, and de-risked multiple possible onshore routes. As a result of five years of full-time work, the project is materially less risky than the CLB lease areas.

In contrast to the Kitty Hawk lease area, the CLB lease areas were sold just this past May and already face development challenges. As was detailed in our previously submitted Limited Comments, numerous local and regional stakeholders, as well as the North Carolina congressional delegation, have publicly expressed opposition to the development of offshore wind in the CLB lease areas within 24 nautical miles from shore due to viewshed concerns. This buffer would effectively eliminate as much as half of each CLB lease's acreage absent significant time and effort to resolve these concerns. Our team has extensive background working with coastal communities and government officials in both the northeast and the southeast, and our hard-won experience has taught us to take viewshed objectives very seriously, especially when tourism is a factor. The 24-nm "horizon limit" is a very real concept for North Carolinians and building inside that boundary will generate substantial challenges for both CLB projects.

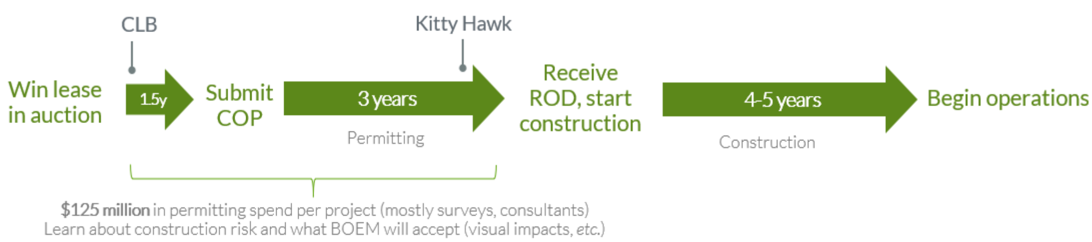
CLB lease areas have other significant permitting and development risks that will take months and even years – not weeks – to resolve, regardless of staffing levels.

For example, there is currently no turbine on the market that is rated to withstand the hurricane-force wind levels experienced in the CLB lease areas, forces which have historically not been present in the Kitty Hawk lease area. Waiting for turbine technology to overcome this challenge could significantly delay any project on the CLB lease areas.

Taking an arms-length assessment of development and schedule risk, Kitty Hawk's five-year head start and the fact that its entire zone is beyond the important 24-nm viewshed buffer, means that its COD estimate of 2029-2030 has a much smaller margin of error than the CLB lease areas.

A timeline showing Kitty Hawk's current status vs the CLB lease areas is below in Figure 3.

FIGURE 3



While it is theoretically possible to reach commercial operations within eight years of signing a lease, that timeline is significantly impacted by the permitting backlog, developer experience, and lease area characteristics, and also demands high, at-risk spend that the rest of the offshore market has not been willing or able to bear. The CLB lease areas do not have any special relief on any of these factors, so assuming an eight-year timeline for either is very risky.

The Commission should review the lease areas on their merits to assess their ability to achieve a given COD. Kitty Hawk is well within reach of a 2030 deadline, needing only a commitment for offtake to advance the project at all pace towards North Carolina. This material difference must be reflected not only in the modeling exercise, but also in the way that the Commission requires Duke to approach offshore wind – by making an arms-length assessment of the lease areas and choosing to develop the best one first.

Q. DR. STARRETT, YOU FOCUS EXTENSIVELY ON THE DIFFERENCES BETWEEN THE LEASE AREAS. IN WHAT WAYS ARE THEY LIKELY TO BE SIMILAR? AND WHAT ISSUES OTHER THAN NEAR-TERM DEVELOPMENT ACTIVITY FROM THE ISSUES REPORT DOES THIS QUESTION AND ANSWER ADDRESS?

A. Other than "Near-Term Development Activity—prudence of development work and need for long-lead time resources", this question and answer addresses the "Transmission Planning, Proactive Transmission, and RZEP" issue.

As an experienced offshore wind developer, we consider that roughly 80% or more of a project's capital cost can be estimated at a relatively high confidence level even prior to a single survey being completed. This is because major components such as wind turbines, foundations, substations, and export cables can use reference pricing with some adjustments to accommodate for differences in variables like cable length and water depth. As surveys come in with foundation soil data, for example, these estimations are further refined to close out the remaining 20% of uncertainty.

Significant survey work has already been completed for Kitty Hawk, and the resulting data demonstrates excellent site conditions with very low constructability risk. No survey work has been completed within the CLB lease areas, so the relative cost profile of possible projects out of CLB contains only downside risk compared to the well-understood, positive Kitty Hawk benchmark.

With that background, we summarize the capital costs for a single offshore wind project in the CLB and Kitty Hawk lease areas as materially equivalent, subject to upward revisions at CLB in the event of negative survey data in the future.

In specific, CLB and Kitty Hawk:

- Would have similar foundation costs owing to similar depths, with Kitty Hawk being fully de-risked with confirmed excellent soils and CLB having an open risk pending site survey data by their respective owners;
- Would both deliver to the same point of interconnection in the Havelock/New Bern area;
- Would both require HVDC technology to reach Havelock/New Bern; and
- Would both therefore be "right-sized" at roughly 1,300 MW and face the same grid upgrade costs.

In their testimony, Duke stated "Kitty Hawk [has] as significantly longer subsea cabling requirement due to its location near the North Carolina/Virginia border" as a way of positively differentiating the CLB lease areas from Kitty Hawk.

Having contracted for more than $1 billion in offshore export cables in the US alone, we disagree. As shown in Table III-2 of our Limited Comments, we assess the Kitty Hawk export route as being roughly 25 km longer to Havelock/New Bern versus the distance there from the CLB lease areas. This represents a total project cost differential of less than 0.4% - a difference that is not material to the business case.

Q. DR. STARRETT, PLEASE EXPLAIN THE ENGINEERING DIFFERENCES BETWEEN THE OFFSHORE LEASES IN MORE DETAIL.

A. Beyond the capital cost, the other major value driver for an offshore wind project is wind speeds. Higher wind speeds translate to better net capacity factors ("NCFs"), producing more energy and reducing the levelized cost of energy ("LCOE") of the project. Within capacity expansion models, these more productive, lower LCOE resources offset the need for additional generation to be selected, thereby reducing portfolio present value of revenue requirement (PVRR).

In estimating production from a zone, an initial desktop exercise can use data from nearby meteorological buoys and model reanalysis data, refining further once a floating LiDAR buoy is deployed in the zone. For reference, the Kitty Hawk lease area has had two such floating LiDAR buoys deployed to-date over a period of multiple weather years which leads to a very high confidence in the expected wind speeds and production there.

Duke, in their testimony, characterizes all of the southeastern offshore lease areas the same, as having "high-capacity factors." But this mischaracterizes *the* major disadvantage of the CLB lease areas – that they have the lowest wind speed of any auctioned lease area in the country. Avangrid Renewables estimates a 36% NCF for CLB lease areas versus a 43% NCF for the Kitty Hawk lease area. Wind speed, like solar resource, is immutable. There is nothing developers can do to improve this basic meteorological characteristic of the region.

Put in terms of CapEx, based on a simple but reasonable financial equivalence of about $50 million per percent change in NCF, projects on a CLB lease area would need to be constructed for *$850 million less* than Kitty Hawk to overcome the lower wind speeds present in the CLB lease areas and provide the same value to ratepayers. But as we stated earlier, the construction cost between the two sites will be materially identical. Therefore, based on NCF alone, the CLB lease areas would deliver energy with an LCOE of about $10 to $15/MWh higher than Kitty Hawk's LCOE. That is a cost that ratepayers would feel directly regardless of the mechanism for cost recovery.

Just as sunnier solar leases and more efficient gas plants are better deals for ratepayers, so too are lease areas with faster average wind speeds. Therefore, considering that Kitty Hawk and the CLB areas have overall similar capital costs and very different net capacity factors, we conclude that on an overall value basis – cost versus production – neither of the CLB lease areas should be considered the least cost and most prudent offshore wind resource available to North Carolina at this time.

Q. MS. GALLAGHER, WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION?

A. We see early action on offshore wind, specifically the Kitty Hawk lease area, as the only path to achieve a 70% reduction by 2030.

Our recommendations to the Commission are to: (i) include offshore wind in the final Carbon Plan; (ii) within 6 months of the final Carbon Plan being issued, initiate a formal process to compare and prioritize regional offshore wind resources based on cost, efficiency, viability, and COD schedule; and (iii) direct Duke to take all reasonable steps to procure offshore wind that can achieve the objectives of HB 951.

Our recommended approach to recommendation (ii) is to procure an independent third-party study that makes a bottoms-up calculation of LCOE, PVRR, or similar metrics, based on owner-supplied and third-party verified inputs, technical and permitting viability, schedule, size, and overall plan, along with any other Commission-determined metrics. Such a study should solicit information from developers in a manner that ensures confidentiality and accountability.

We also recommend incorporating stakeholder input and regular reports to the Commission about the status of the study, filing of the final study, and an opportunity for intervenors to file comments in a timely fashion regarding the study.

Immediately following the conclusion of the study, our recommendation (iii) suggests the Commission should require Duke to pursue offshore wind resource additions in order of their best overall value and ability to meet the 2030 deadline. In the case of the CLB lease areas, were the study to show either as a top priority, we do not believe any immediate action is necessary to hasten their development progress – federal requirements play that role already. If the analysis shows Kitty Hawk to be the best option for ratepayers, only Duke's immediate firm commitment could unlock the project's full potential for North Carolina – as the keystone to meeting its necessary and urgent climate goals.

Q. MS. GALLAGHER AND DR. STARRETT, DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes. Thank you for the opportunity to provide testimony on these topics.

Summary of the Direct Testimony of Dr. Michael Starrett and Ms. Becky Gallagher on behalf of Avangrid Renewables, LLC.

The purpose of our testimony was to address the topic of "Near-Term Development Activity—prudence of development work and need for long-lead time resources" topic, particularly with regard to the development of the Kitty Hawk lease area into an offshore wind facility.

In our testimony we covered a number of topics related to the Carbon Plan, the available offshore wind resources, and the Kitty Hawk lease area. We would oppose the Commission approving the proposed Carbon Plan offered by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress LLC ("DEP") (DEC and DEP collectively herein referred to as "Duke").

We discuss the importance of offshore wind to meeting North Carolina's House Bill 951 ("HB 951") urgent carbon emission reduction of 70% reduction by 2030. Offshore wind could offer important generation diversity benefits to the North Carolina fuel mix, especially valuable as solar proliferates. The technology is mature, with over 55 gigawatts of offshore wind in operation globally.

We stress the need for the Commission to take an objective, arms-length approach to offshore wind development. Only then can it select the best possible path forward for ratepayers. Duke's direct testimony indicates their preference to advance Duke Energy Renewables Wind LLC's OCS-A 0546 lease area first. But based on our own assessment and on publicly available data, this lease area has a weaker profile than the Kitty Hawk lease area on four key metrics that would directly impact ratepayers: wind speed, capacity, schedule, and risk. Duke has not done a sufficient comparative analysis of the OCS-A 0546 lease area prior to proposing their purchase of it.

We discuss the offshore wind permitting timing, and that Kitty Hawk lease area is the only offshore wind lease area that can reasonably bring power to North Carolina by 2030 given its advanced permitting status: the project has submitted both its Site Assessment Plan ("SAP") and Construction and Operations Plan ("COP"). Because the federal government requires all owners to progress their projects to SAP and COP on pre-established timelines, there is no need for Duke to purchase the OCS-A 0546 lease area to achieve these goals.

We also discuss Kitty Hawk's advantages versus other lease areas on permitting and engineering topics. On permitting, we outline the Bureau of Ocean Management ("BOEM") queue delays as well as the risk of starting construction ahead of permit approval. We also discuss OCS-A 0546 development risks including viewshed and hurricane. On engineering, we clarify that CapEx and OpEx are likely to be similar between the lease areas, but that the Kitty Hawk NCF's is materially higher, which alone could save ratepayers $10-$15/MWh on a levelized cost of energy ("LCOE") basis.

We make it clear that further development action towards a 2030 commercial operation date would require near-term commitment from Duke. We state that Avangrid is open to all manner of transactions that are on reasonable terms and fairly value the asset.

We conclude with three recommendations:

(i) include offshore wind in the final Carbon Plan but not in the manner proposed by Duke; (ii) within 6 months of the final Carbon Plan being issued, initiate a formal process to compare and prioritize regional offshore wind resources based on cost, efficiency, viability, and COD schedule; and (iii) direct Duke to take all reasonable steps to procure offshore wind that can achieve the objectives of HB 951.

Thank you for your time.

MR. SMITH: At this time, Chair Mitchell, the Panel of Ms. Becky Gallagher and Doctor Michael Starrett is now available for questions from parties and the Commission.

CHAIR MITCHELL: Let's see. We've got CIGFUR.

MR. CONANT: Good afternoon. D.C. Conant in for CIGFUR II and III. I hope you-all are doing well.

CROSS-EXAMINATION BY MR. CONANT:

Q. Ms. Gallagher, in your testimony on page 24 starting at line 1 -- give me a moment to get there.

A. Okay.

Q. You provide recommendations to the Commission. Is that right?

A. That's correct.

Q. In those recommendations, you recommend that the Commission initiate a study process to compare and prioritize regional Offshore Wind resources based on costs, deficiency, viability, COD schedule, correct?

A. That's correct.

Q. Further elaborating on that recommendation, at line 7, you suggest that a bottom-up calculation of LCOE, PVRR, or a similar metric be used for the comparisons. Is that right?

A. That's correct.

MR. CONANT: At this time, I'd like to introduce an exhibit. Chair Mitchell, I'd like for this exhibit to be marked and identified as CIGFUR Avangrid Panel Direct Cross-Examination Exhibit 1, which I'll represent to be the EIA levelized costs of new generation resources in the Annual Energy Outlook.

CHAIR MITCHELL: The document will be marked as CIGFUR II and III Avangrid Panel Direct Cross-Examination Exhibit 1.

(WHEREUPON, CIGFUR II and III Avangrid Panel Direct Cross-Examination Exhibit 1 is marked for identification.)

Q. Doctor Starrett, could you turn to page 9 of the document and look at Table 1-B.

A. I'm there.

Q. All right. It shows the estimated unweighted levelized cost of electricity and levelized cost of storage for New Resources Service in 2027?

A. I see it.

Q. If you look at the last column for the dispatchable technologies and the resource constrained technologies categories only. Does Offshore Wind have the highest

LCOE?
A. Yes.
Q. What is the LCOE for Offshore?
A. The LCOE for Offshore, and I'm reading this table, is 103.77, acknowledging that this is a public document, not something that I produced.
Q. Absolutely. Could you now turn to page 22 of the document.

MR. SMITH: I don't have an objection, but I actually think he -- did you say the total LCOE?

MR. CONANT: The total LCOE, you can include the tax credit. My mistake on that.

MR. SMITH: So is it the -- is it the last column?

MR. CONANT: It's included in the tax credit. Yes, the last column.

MR. SMITH: Mr. Starrett, would you mind reading the number for Offshore on the total LCOE.

THE WITNESS: Oh, sure.

MS. LINK: Chair Mitchell, I don't know that that's an objection. That is redirect of -- the witness answered the question.

MR. SMITH: I'll save it for redirect.

BY MR. CONANT:

Q. Now, on page 22 in -- for Table B-1(b), this table shows the estimated unweighted levelized cost of electricity and levelized cost of storage for new resources entering a service in 2040. Again, if you look at the last column for the dispatchable technologies and resource constrained technologies only, does Offshore Wind have the highest LCOE?

A. As I read through the table, Offshore Wind has the highest LCOE. I would caveat it to say a few things. One, I don't know anything about the characteristics that are being described here or I can't comment in any way on whether or not the capital costs are right. I also don't know what the financing is assumed, and I don't know anything about the tax credits. I also don't know in what way this would be considered whether it's part of a PVRR portfolio or it's meaning to fit in, but to your specific question, it's the highest LCOE in this table.

MR. CONANT: Thank you. That's all.

CHAIR MITCHELL: All right. Let's see. Tech Customers.

MR. SCHAUER: Chair Mitchell, no questions for Tech Customers.

CHAIR MITCHELL: All right. Thank you,

Mr. Schauer. Walmart, you're up.

MS. GRUNDMANN: Good afternoon. My name is Carrier Grundmann on behalf of Walmart.

CROSS-EXAMINATION BY MS. GRUNDMANN:

Q. Let's go back to page 24 of your direct testimony with respect to the final recommendations to the Commission. Were you-all in the room this morning when counsel for the Company was discussing with the Public Staff potential issues with a third-party mandated study of the three Offshore Wind parcels?

A. (Ms. Gallagher) Yes, I was.

Q. If the Commission were to direct such a third-party independent study of the three Offshore Wind parcels located off the coast of North Carolina, would Avangrid intend to participate in such a study?

A. Yes.

Q. Turning to page 14 of your testimony, I don't believe you were in the room, but curious if you may have been following along to the live stream when the Company's Long Lead-Time Resources Panel was testifying, were you-all watching that testimony?

A. At least a part of it.

Q. Did you recall that there was some -- I guess I would describe it as confusion, but some -- the Company didn't seem to know for sure whether Avangrid would be open to selling the Kitty Hawk parcel to the Company, so I want to discuss that with you. And it sort of calls upon the question and answer beginning on line 3 on page 14 of your testimony. Is Avangrid, sitting here today, willing to discuss with the Company the sale of its Kitty Hawk land lease -- Offshore Wind lease to the Company?

A. Yes.

Q. Does Avangrid believe that it would be helpful in terms of any such negotiation for the Commission to resolve the legal question described, I think in your brief, at lines 11 to 13 on the legal issue of third-party ownership?

A. Yes.

MS. GRUNDMANN: Thank you. Those are all the questions I have.

CHAIR MITCHELL: All right. Public Staff.

MR. FREEMAN: One moment, Commissioners. Thank you.

(Pause)

MR. FREEMAN: Thank you. No questions.

CHAIR MITCHELL: All right. Thank you. Duke Energy.

MS. LINK: No questions.

CHAIR MITCHELL: All right. Let me check in with Commissioners. Commissioner Clodfelter. Oh. I'm sorry. Redirect, Mr. Smith. I'm sorry. Go ahead.

MR. SMITH: No worries. I believe there's just one thing that's within the scope of redirect, going back to that LCOE chart.

REDIRECT-EXAMINATION BY MR. SMITH:

Q. CIGFUR II and III Avangrid Renewables witness Starrett and Gallagher Direct Cross-Examination Exhibit 1, do you have that?

A. (Mr. Starrett) Yes.

Q. And would you mind stating the correct total LCOE for Wind Offshore located on page 9?

A. Yes. Thank you very much. I had stated 103.77. In this table, it's 105.38, and I just want to expand a bit more on a statement that I had made, especially as it relates to cost, especially when I think about renewable systems. We are very comfortable and familiar in general with costs, thinking about them. I'm just dispatchable. Whenever it is you start to get into higher renewables systems, you will always have the lowest cost, you know, being bare likely desert solar across the country, and you need to work your way up the merit order of dispatch, always.

I'm not suggesting that this number to me is not familiar to me at all, so it doesn't ring a bell in any way, but it should be the case that whenever it is you're thinking about LCOEs, you're thinking about it in the context of the fit to the portfolio and what it brings to the overall system.

So while I acknowledge that Offshore Wind is the highest in this table, I would disagree that it's the least economic resource for any portfolio.

MR. SMITH: Thank you. Nothing further.

CHAIR MITCHELL: All right. Commissioner Clodfelter.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Doctor Starrett, were you listening to the testimony of the Duke Long Lead-time Resources Panel when Mr. Pompee accused Avangrid of a $500 million mathematical error in its direct testimony?

A. Yes, I was.

Q. Do you have a response to that accusation?

A. Yes, I was, and thank you very much for the opportunity to clarify that. In the Renewables develop business, it's quite common to think in terms of percent change rather than percent, and that's because your starting point matters a lot. So when we're representing the LCOE of the Carolina Long Bay and Kitty Hawk, it serves as 36 and 43 percent respectively. That differential change, right, the relative change between 36 and 43 percent is a 20 percent improvement, okay.

So when I'm talking here about $50 million dollars per percent change, that's the relative percent change. That's 20 percent. 20 times 50 is somewhere in the ballpark of $850 million, all those being rounded, but I said it's about 50 million per percent. It's about 20 percent. So if you get down into the details of the math, that's what it would be. Is that clarifying?

COMMISSIONER CLODFELTER: Thank you for the answer.

CHAIR MITCHELL: Additional questions from Commissioners? Go ahead.

EXAMINATION BY COMMISSIONER KEMERAIT:

Q. I have a question in regard to page 21, and it looks like on line -- beginning on line 17 and 18 dealing with the statement about capital costs and that the Kitty Hawk and Carolina Long Bay lease areas would be basically equivalent if they were right size at approximately 1300 megawatts and face the same network upgrade costs. I think we heard something a little bit different about the network upgrade costs from the Duke Witness Panel. Can you explain what studies you elaborate upon about those network upgrades, costs being roughly equivalent.

A. (Mr. Starrett) Yeah. Thanks very much, and I want to just -- to the extent that it's acceptable to the Commission, I want to maybe just take a little bit to elaborate on this in concept, because sometimes, I think if you take -- it can be helpful just to take a step back. Whatever it is that you have in Offshore Wind project, and we've looked at bids and are developing a lot of them, whenever it is that you have on -- and you're more than about 100 kilometers from where ever you're going to make landfall, you're probably going to buy an HPDC solution. That's about the break-even point. So from that perspective with both Carolina Long Bay and the Kitty Hawk lease area, both being 100 kilometers away, they would be both seeking to interconnect at whatever the best opportunity is, both using HPDC, so I just want to sort of put it initially to say they're probably both looking for the best point of interconnection.

Our disagreement in the way in

which we challenge the point of interconnection in there is not to say that we think that the Company's identified point of interconnection of New Ben is the wrong interconnection point. Actually, we acknowledge fully that it's a strong point of intersection. Our disagreement is actually a little bit simpler. It's more around how the resource is being considered from a modeling perspective. So here's what I mean by that. Usually, when you're building a portfolio expansion model like EnCompass, you have tranches for a reason, so you would have -- if you were doing this and you were trying to build the first most efficient Offshore Wind project that you possibly could, you would find the lowest cost upgrades that you possibly could. To the extent that there's more appetite in the model for something additional to that, you would, you know, test the model, but show what the extra cost of that.

So when I'm challenging the interconnection solution proposed by the Companies where both the first 800 and then the second 800 are both working their way towards New Bern, and then triggering large upgrades there, I'm not disagreeing that New Bern is not a good point of interconnection or strong point of interconnection. It's a point of interconnection that's available to both of the resources cost. It's available -- upon communications, it's available to both of the resources. And it might be the right choice depending on your appetite, the model's appetite, what it's putting forward. What we were challenging in our testimony is just simply that.

If you were trying to fill that first tranche in the model, as low-cost as you possibly could, you would have looked at other solutions. That's the challenge that we have there from interconnection. We also made statements about them being of equivalent cost, which I'm happy to expand on. But since your question was just limited to the transmission, I'll pause to see if you have an interest in further comment.

Q. All right. My question was just specific to the network upgrades because I think that that was a criteria that Duke use to differentiate the cost between the two projects.

A. I don't recall that Duke differentiated the cost between the Carolina Long Bay and Kitty Hawk leased to us by upgrades. I think the differentiation that they were really trying to make was on the export cable laying, and here I'm happy to speak to that. So when you have an Offshore project, you will always be buying cable laying from the Offshore substation to the landfall, which will be a summary and cable that's buried usually about a meter and a half below the seabed. You'll land, and then you'll take whatever you're on to route it is to whatever your point of interconnection is.

So just initially, maybe we can allow that for whatever the point of interconnection is. Whatever's happening, Onshore will be the same, once it makes landfall. I think the point that Duke was seeking to raise was really specifically around the length of the route to get there with the argument that the Carolina Long Bay is the least -- it's closer from their perspective. I would challenge that from two perspectives.

The first is, you know, our limited comments. We put forward an Offshore export cable route and identified the cable lengths associated with it, both from our lease area and from Carolina Long Bay. We had them as being about 25 kilometers different. And I indicated in my direct testimony that from our assessment, and we've procured more than a billion dollars of Offshore cables, it's not a material cost.

25 kilometers of Offshore cable is not a big deal, right?

And I can tell you just to put some precision on that, it's about a million dollars per kilometer. So for 25 kilometers at $25 million, that's a lot of money for some things but it's not a lot of money for a big, giant 1.3 gigawatt project. Duke further challenged that the cable laying corridor that we had identified would not have been acceptable for permitting. And there, what I can say is Avangrid Renewables has about 175 people in the U.S. Our development team is -- I actually looked this up. Our development team is 21 -- our development permitting team has 21 staff members as of today. Our engineering team has 41, and our construction team has 26 people. That team, each -- the director level of people from each of those teams have been to North Carolina, evaluating that Offshore export cable corridor, and we were specifically guided as a preference to there by the National Park Service and the North Carolina Division of Marine Fisheries.

COMMISSIONER KEMERAIT: Thank you very much.

THE WITNESS: You're welcome.

CHAIR MITCHELL: Just a few questions.

EXAMINATION BY CHAIR MITCHELL:

Q. Do I understand correctly that the Kitty Hawk lease has two sections? There's North and South?

A. (Mr. Starrett) I'll just try to be as super clear as I possibly can. Whenever it is you buy a lease area, you submit a COP, right? It's your Construction Operations Plan. You designate within that area that you're talking about. We have differentiated -- we submitted two COPS for Kitty Hawk. One is we call Kitty Hawk North, which is a certain number of positions, and it goes -- as Duke was pointing out, its current interconnection route is to Virginia, although we could change that at any time. The second one, which is called Kitty Hawk South, is a separate COP that we filed, and that is still open to where it's going.

Just to give a scale of that, the capacities of the total zone is about three and a half gigawatts, more or less. Two-thirds of that is in Kitty Hawk South. So in this -- I think it's important to note that although we're always comparing Carlina Long Bay, Kitty Hawk South, Kitty Hawk, when we're saying Kitty Hawk South, and I think when most people are saying it here, they're not -- they're talking about that bottom two-thirds which is roughly 150 percent bigger than either of the Carolina Long Bay lease areas individually. Is that helpful?

Q. What do you mean when you say "bigger"?

A. I have it in acres or in positions, but it's about -- the Carolina Long -- all right. So just to not get into too much of the jargon, we think in terms of positions which is just a place in the ocean that you can put a wind turbine. We do that because wind turbine capacities are growing so quickly that if you try to save the megawatts, you'll be wrong within a year. So the Kitty Hawk lease area, Kitty Hawk South, has 120 wind turbine positions, more or less, so you could call it about two and a half gigawatts of capacity.

The Carolina Long Bay lease area area, from our perspective, and we have a talented team, we looked at Carolina Long Bay. We had considered to participate in the lease area, so we did a lot of diligence on it. The Duke -- okay. I don't have that, but the one that Duke -- renewable zones at 546, we have that as being out of most, 90 positions and our own risk assessment. You could take what you want about the 24 nautical mile buffer. We took it seriously. It would put you down 46 positions.

So when I say "bigger," I mean 121

positions up in Kitty Hawk South, not more than 90, and some were between 90 and 46 as a more likely base case for the Carolina Long Bay lease that are owned by Duke Renewables.

Q. Okay. And at this point in time, has an interconnection request been submitted either to PJM or into DEP for either the lease areas?

A. Kitty Hawk North has an interconnection request filed -- we filed it pretty close to when we were really kicking off with that zone for a total of 2.4 gigawatts, which I just mentioned we think would have 2 and a half there and just reflects how capacities have grown. And we have not filed anything into Duke. We have in Q-1 of '23, our development team is going to be coming down to North Carolina to meet with some of the towns we are considering making landfall at to help us to mature our understanding, but where we would make landfall and then where we file interconnection to. I would say overall, what Kitty Hawk South needs is clarity of where go. When Kitty Hawk South has clarity where to go, we'll file an interconnection request.

Q. Okay. Is it possible that the leases could be combined into one point of interconnection such that if you were able to proceed through the PJM queue, you could proceed with the entire lease area? I see you're shaking your head. So is that a yes?

A. (Ms. Gallagher) Yeah, absolutely. That's why in our testimony, we didn't split hairs between Kitty Hawk north and Kitty Hawk South. Yes, it's true. They have separate COPS, but it's also true that the entire zone could deliver it to North Carolina with, you know, revision of the COP. That's not a big deal.

Q. Similarly, it could go to PJM.

A. Correct.

Q. The entirety --

A. Correct.

Q. Okay. Okay. Last question. The conversations about that you just indicated you-all are going to have with local communities or authorities about coming on shore, are you anticipating being able to connect, interconnect with something -- with a utility other than DEP?

A. (Mr. Starrett) No, sorry. But yeah, just to clarify that. Whenever it is you interconnect, you'll usually have to file and negotiate with the town or host a community agreement in order to travel roadways, et cetera. We've done this a couple of different times.

So as an example, when we were looking at the Carolina Long Bay lease areas, we had thought about well, what are the communities, what are their oppositions, is this a place that you would ever make landfall. You're thinking of all kinds of things. It's the same story here. You know, when our team had come down previously, we met with -- as I said, we met with the Department of Transportation to understand their interest in our ability to travel on the roadways. We met with -- just, you know, the National Forest Service about traveling through the forest there, and so on. So our trip down here is really just about getting feedback from the communities about where a potential landfall might make the most sense for the communities that are available there. It's always anticipated that interconnection in DEP is what we were targeting in North Carolina.

CHAIR MITCHELL: Okay. All right. Thank you. Let's see if there's questions on Commissioner's questions. We'll start with -- let's see. Let's start with intervenors.

MR. CONANT: No questions.

MS. GRUNDMANN: No questions.

MS. LINK: I do have a few.

CHAIR MITCHELL: Go ahead.

MS. LINK: Thank you, Chair Mitchell.

EXAMINATION BY MS. LINK:

Q. Good afternoon. My name is Vishwa Link. I'm here for Duke Energy. I wanted to first discuss with you the routing of the Sub-C cable, and I believe you mentioned an exhibit that was to your limited comments. And if you have those there?

A. Uh-huh (yes).

Q. (Mr. Starrett) Are you talking about page 42, and is it Figure 3-4, potential interconnection routing from the Kitty Hawk Wind lease? It's the last page of those comments, I believe.

A. Okay. We have it here. Yes.

Q. And in those comments, you have a Table 3-2, summary of cable route lengths, and it states for the New Bern 230 kV, point of interconnection, the cable route length to Kitty Hawk in kilometers is 266 kilometers. That's correct?

A. That's correct.

Q. And then you state the estimated cable route length to Carolina Long Bay lease is 248, correct?

A. That's correct.

Q. And that's where you're getting your differential of 25 kilometers?

A. That's correct.

Q. Okay. And if we're looking at the map that's a little bit about the Table 3-2, the Figure 3-4, the route that is shorter, that's going through the Pamlico Sound, correct?

A. That's correct.

Q. And that's the route that you said the marine -- you said two organizations got supported?

A. Yeah. Uh-huh (yes). The National Park Service and also the North Carolina Division of Marine Fisheries suggested that as a potential preferred route. Of course permitting could take you all kinds of directions, but that's what's we're starting with.

Q. All right. Let's move to a discussion you had, I believe, with Chair Mitchell about if you wanted to change the point of interconnection with Kitty Hawk North or Kitty Hawk South, I believe you said you could change it any time, no big deal?

A. That's -- well, we don't do development, and they say everything that we propose is a big deal. But what I should maybe clarify as to say it is absolutely within the ability of your team to either amend a COP or before and after the Record of Decision.

Q. So right now, you are before the record of decision, both the Kitty Hawk North and Kitty Hawk South, BOEM process, correct?

A. That's correct. Both are filed and both are in process. Both will have record of decision in the middle of this decade.
Q. All right. And if you amend your COP to change your point of interconnection, don't you start over at the BOEM process?
A. No, you don't.
Q. All right. So when you said both are expecting a Record of Decision by -- you said the end of this decade?
A. The middle of this decade.
Q. By the middle of the decade. But they have different timings, correct?
A. That's correct.
Q. And what is the timing for the Record of Decision in Kitty Hawk North? The timing of the record decision for Kitty Hawk North, I believe we're currently antic -- you could check it on the permanent dashboard. We have it. The permitting dashboard is estimating it in 2026.
Q. For Kitty Hawk North?
A. (Mr. Starrett) Is this for Kitty Hawk North?
A. (Ms. Gallagher) South. Oh, sorry.
A. (Mr. Starrett) I don't recall what -- it is available on the permitting dashboard. I don't recall it for Kitty Hawk North.

MS. LINK: Chair Mitchell, just for clarity of the record, I do have two very quick exhibits from the BOEM website north and south. May I hand those out?

MR. SMITH: Uh-huh (yes). Chair, I'd like to put in an objection. I think this is outside of the scope of the Commissioner's questions.

MS. LINK: I believe it's well within the scope. He asked about North and South. He asked about permitting. He asked about whether it could go to PJM or both go to North Carolina.

CHAIR MITCHELL: I'll allow it. Overrule the objection. All right. Let's go ahead and mark the first document.

MS. LINK: Chair Mitchell, they look a little identical, so let's try the Kitty Hawk North Wind Project. It's sort of the title --

CHAIR MITCHELL: You said north?

MS. LINK: North.

CHAIR MITCHELL: Okay.

MS. LINK: Duke Energy Avangrid Direct Cross-Examination Exhibit 1, I believe.

CHAIR MITCHELL: Okay. The document will be so marked.

(Whereupon, Duke Energy Avangrid

Direct Cross-Examination Exhibit
1 was marked for identification.)

MR. SMITH: I only have two copies of -- okay.

MS. LINK: They look very similar, but one says North, one says South.

MR. SMITH: I'm good.

MS. LINK: May we mark the Kitty Hawk South Offshore Wind Project -- actually, it says DEC/DEP. Let's say Duke Energy Avangrid Direct Cross-Examination Exhibit 2.

CHAIR MITCHELL: It'll be so marked.

(Whereupon, Duke Energy Avangrid
Direct Cross-Examination Exhibit
2 was marked for identification.)

MS. LINK: Thank you.

MS. GRUNDMANN: Can you confirm we marked North as Exhibit 1 and South as exhibit --

CHAIR MITCHELL: That's correct. North is 1, South is 2.

MS. GRUNDMANN: Thank you.

MR. SMITH: I still only have the North.

MS. LINK: May we have the South document handed to the witnesses, please. All right. Does everyone have a North and a South?

CHAIR MITCHELL: Everybody just come to

order. Please pass out North. So these people get North. Who does not have two documents? Raise your hand. All right. Ms. Link, you can please proceed.

MS. LINK: Thank you.

BY MS. LINK:

Q. All right. So the Kitty Hawk North Wind Project is Cross-Examination Exhibit 1 and the Kitty Hawk South is Cross-Examination Exhibit 2, just to keep them straight, for the record. So just walk through the North document, in the description, it says in June, 2022, the project name was changed from Kitty Hawk Wind Project to Kitty Hawk North Wind Project. Do you see that?

A. Uh-huh (yes).

Q. To reflect the segmenting of the project?

A. Uh-huh (yes).

Q. And this is the -- the North parcel is the one -- if you turn it over -- well, actually, excuse me. It's going to interconnect into Virginia Beach, correct?

A. That's where it's always CC. It's Offshore Export Cable Corridor is currently designated, that's correct.

Q. And that's in the PJM queue, correct?

A. That's correct.

Q. And that's the PJM queue that's been halted and support

being restudied?
A. I wouldn't use the characterization "halted," but there's a -- yeah, pretty significant change in how they're processing moving it to a cluster study.
Q. Okay. How long has that been pending in the PJM queue?
A. I don't recall the date that we filed. It may be -- I don't recall.
Q. Okay. If you turn to the back page, and you see the second bar, Constructions and Operations Plan, when does that say that the Kitty Hawk North parcel is expected to get its COP?
A. Well, its COP was filed in -- last year, May of last year, something like. And this -- it doesn't -- so just -- for the avoidance of doubt, this doesn't give a word on it that says ROD, but the COP -- I think your question might be --
Q. When is the Record of Decision expected in the COP for the Kitty Hawk North?
A. I don't -- I want to answer your question but I want to be -- answer it in a specific way that you're asking it. And on this page, I don't see any marker that you might be referring to with respect to ROD. Are you referring to any marker in particular on this page?
Q. I would ask you as the expert. When do you expect the

Record of Decision for Kitty Hawk North?
A. Is that related to the document that you filed in here or is there something specific that you're looking at?
Q. I'm looking at the back page of Kitty Hawk North, and it says of the construction operation's plan. It has the end of the bar at April of 2023. Is that when you expect the record of decision?
Q. Oh. I see what -- I understand your question. The process is a little bit different when you're going through it. So just to put it in big blocks, and you have a SAP, which we've talked about quite a lot. You will prepare a COP that will maybe take two to three years. You will submit the COP. BOEM will review it for a period of time. BOEM will issue an NOI which is a Notice of Intent. From the Notice of Intent to an approval of the COP is usually two years. And after review -- after approval of the COP a month or two later, a couple months later, you'll have a record of decision.
I don't see the deadline here for record of decision. And as I stated earlier, I don't recall what the absolute latest indication from BOEM was, and I don't see it here to fresh myself to be able to make a statement about it.

Q. So does the April of 2023 where the second bar ends, is that the approval of the COP?

A. It seems like a reasonable guess, but as I said, I don't recall. I'm not sure.

Q. So it's your --

MR. SMITH: Objection. Asked and answered.

MS. LINK: I didn't ask a question yet.

MR. SMITH: Ask your question then.

Q. My question is, is there no where on this bar chart where you can surmise where a Record of Decision would be, from your experience?

A. Looking at the piece of paper that you presented and handed to me, I do not see the word ROD. I would remind that we have a team of 21 people in Permitting and Developing at our business and would just simply say that as it relates to the anticipated ROD for Kitty Hawk North, I don't recall.

Q. Okay. So let's go to Kitty Hawk South then.

MS. GRUNDMANN: Your Honor, real quickly, I just have some concerns about this document. If you look at the back of the page, up at the top where the bars are, you can see that there's the beginning of a word.

A. Yeah.

MS. GRUNDMANN: After April, it goes "A

something." So I've actually pulled it up on my phone, and there does appear to be more dates, so I have some concern that the printout itself didn't accurately print. Like it's one of those situations where ever it's formatted on the web page, it didn't print accurately. And so what I see when I look on the internet, on the website used on the bottom of this page, and what's on the back of this page, don't perfectly match up, and so I can't -- I just --

CHAIR MITCHELL: I'm with you. Let me let Duke respond.

MS. GRUNDMANN: Thank you.

MS. LINK: Yes. Chair Mitchell, it's a fair point, and I noticed that as well. The only questions I had are about the construction operation plan bar, which does have an end point of April of 2023, and I'm sure on the internet, it matches. And so we can absolutely supplement, for the record, something that prints it all the way out with the other dates.

CHAIR MITCHELL: Okay. Well, I would like you to do that.

MS. LINK: Absolutely.

CHAIR MITCHELL: So when you make the filing and y'all indicate which is the -- sort of the supplemental or whatever we're going to call it, the revised exhibit.

MS. LINK: Yes. Thank you.

CHAIR MITCHELL: Please proceed.

MS. LINK: Absolutely will do so. My apologies.

BY MS. LINK:

Q. So moving now to Cross-Examination Exhibit 2, which is the South parcel, again, it indicates in June of 2022, the project name was changed from Kitty Hawk Wind Project to Kitty Hawk South Wind Project to reflect the segment date. Do you see that?

A. Yes. That's correct. I do see that, yes.

Q. Okay. And this also says, and it's in the third paragraph under "Description," that the Offshore Export Cable will traverse both federal waters and state territorial waters of Virginia and of North Carolina and could have landfall in either the City of Virginia Beach, Virginia, Dare County, North Carolina, Carteret County, North Carolina, and Craven County, North Carolina. And Craven County is where New Bern is correct?

A. I'm sorry. Could you reorient me to this? I'm not quite sure --

Q. Sure.

A. Oh, I see. Yeah, yeah, yeah. Turn the page. Yeah, yeah, I see that. Yeah

Q. Okay. So Craven County, North Carolina is New Bern, correct?

A. I'm not counting -- names is not a -- I'll take your word for it.

Q. All right. Subject to check. And this COP was submitted to BOEM on April 14th, 2022, correct? It's right there.

A. Yes. I believe that's correct, yes.

Q. Okay. And subject to the same critique, Ms. Grundmann had -- and we will correct it when we file with the Commission, but I'm only focused then on a permitting timetable bar, second bar of the Constructions and Operations Plan, and that shows that COP approval around May of 2025, correct?

A. Stating again it concludes in May of 2025, I think what I would -- it's probably easier to think of it more like this: BOEM, it's not binding, but the Bureau of Ocean Energy Management has a commitment. Again, it's not binding of NOI, Notice of Intent to ROD of two years. So we have NOI for Kitty Hawk North, I believe, and Kitty Hawk South is awaiting NOI. Once Kitty Hawk South has NOI, we would anticipate two years to not to have ROD. So why don't we have NOI yet? One of the reasons is just simply that we need to be absolutely confident about where it is that we should take the project. In the event that we have ROD, for example for Kitty Hawk North, as you were pointing out, and we choose subsequent to that, to go somewhere else, we could not restart the COP but make an amendment. I don't have the specifics of that action, but when I brought it up for other lease areas with our development team, they typically told me 18 months is about the right amount of time to consider a major amendment taking place.

Q. So if you were to amend Kitty Hawk North to bring it down to North Carolina and submitted an amendment to COP, it would take 18 months for a Record of Decision after that?

A. Kitty Hawk North could take it -- and subject to check, I believe that the amendment would impact only that export cable corridor, so you would be able to have -- it would be pending -- so you'd be able to do the Offshore works and just would simply not be able to lay your cable, and that would make sense. So you wouldn't be able to lay your cable until that particular segment is approved through the amendment. That's probably fine because cable laying comes -- if you would just target

a 2030 COD, it would be well after 2027.
Q. Okay. But the point is if you amended your COP, it's 18 months for it to be approved?
A. Very important to consider why COPS and Rods matter. You would not be able to get financing --
Q. Chair Mitchell, may I ask him to answer the question. It's a simple question. I just wanted to confirm it's 18 months after you amend the COP to get it approved by BOEM?
A. The very narrow portion that you're amending could take 12 to 18 months, is what our development team tells us.
Q. Okay.
A. Acknowledging, for the record, that you can do all works in all other parts of the COP, which have already been approved, which you're not amending, which would be everything in the Offshore lease area.
Q. Okay. So I just want to turn very briefly then to your Figure 3 in your testimony. It's page 19.
A. Uh-huh (yes).
Q. And so that Figure 3 is intending to show the Kitty Hawk current status versus Carolina Long Bay lease areas status, and as it relates to the BOEM process, correct?
A. Uh-huh (yes).

Q. Okay. And so that has a Wind lease auction in one and a half years, submit a COP. Then three more years, and then receive -- you're calling it the ROD, the Record of Decision to start construction. You see that?
A. Uh-huh (yes). Correct.
Q. Okay. And then there's an arrow for Kitty Hawk, and it says Kitty Hawk is near the tail end of that three years?
A. Yeah. Owing to the flexibility of the lease area being in total, 177 positions, we it reasonable to represent either of the best case. It really just depends on what the preference is. So I would say it is fair that Kitty Hawk is represented as advanced in the permitting, acknowledging that we have two COPS submitted and that we have flexibility in what we do with either of those two lease areas.
Q. All right. So you won the Kitty Hawk lease in 2017, correct?
A. That seems correct.
Q. Okay. So if I take a year and a half plus three years, that's four and a half years, correct? Floor your math.
A. Uh-huh (yes). Yep.
Q. It's late on a Friday. So 2017 plus four and a half

years. That's the middle of 2021, correct, to finish, to receive the Record of Decision? Am I reading the chart right?

MR. SMITH: I'm sorry. Which chart are we on now?

MS. LINK: Figure 3, page 19.

MR. SMITH: Page 19.

A. In general, if you had absolute certainty on your other -- just to be clear, in general, if you had absolute certainty on your path to market, it would be reasonable to assume a more aggressive COP to ROD timeline. That is true. But I want to be extremely clear about this. It is reasonable, relative to assume that you can achieve the best case with BOEM as opposed to when you're searching for offtake and you have less certainty. It's possible that it may not be as quick.

Q. I appreciate that. So 2017 plus four and a half --

MR. SMITH: Chair, I'm going to have to object. I don't recall Commissioners' questions going this detailed into the timing of the different issues related to the Wind lease areas. If I'm misremembering, fair enough, but I don't recall that.

MS. LINK: Chair Mitchell, I thought it important to have on the record the timing for the COP, for both Kitty Hawk North and Kitty Hawk South. The witness had stated he didn't know, and you could check website. So we've gone through now. We have the website. Then I thought there is a figure in here that indicates that by mid 2021, Kitty Hawk should received the Record of Decision. And it's clear from both these documents that that will not be so. So I just wanted to understand what Figure 3 is supposed to be.

MR. SMITH: And I'll just restate I feel like this is very far astray of what any of the Commissioners asked.

CHAIR MITCHELL: All right. I'm going to overrule the objection. I'll let you ask one last question, and then we are -- hopefully, you'll be finished.

MS. LINK: Thank you.

Q. So for the Kitty Hawk South --

CHAIR MITCHELL: Hope is my plan right now.

MS. LINK: I will come through for you.

BY MS. LINK:

Q. For the Kitty Hawk South parcel, an approval of the Construction and Operations Plan in May of 2025, isn't that eight years from when the Kitty Hawk lease was wanted auctioned?

A. It has been the intention of Avangrid Renewables to advance very quickly to Kitty Hawk Hulk North lease area. We submitted a materially complete COP that had all of the -- sort of de -- both recon and detailed service had already been completed for that lease area. There are a lot of preferences that you could make. So the reason that Kitty Hawk North is more advanced as a strategic choice by us and to get that site more advanced more quickly, the Kitty Hawk South site has benefited significantly from that work, not only because some of the surveys continued on to that lease area, but also because since we had done really detailed survey work, soils, etc., in Kitty Hawk North, we were able to build a full ground model for the whole area. We were able to build foundation designs, and et cetera, et cetera, that benefit both lease areas. I can say just for the avoidance of doubt because I'm not quite sure, really, what your question is, the COP has been submitted for Kitty Hawk South. We are awaiting NOI. We're anticipating it soon. Whenever it is that we get an NOI, BOEM has commitment. It's non-binding of two years from NOI to ROD.

MS. LINK: Chair Mitchell, I don't believe that I have an answer to my question, but I don't need to ask any more questions.

CHAIR MITCHELL: All right. With that, I believe -- oh, I'm sorry. Mr. Smith.

MR. SMITH: I just have one question.

CHAIR MITCHELL: Okay. Go ahead.

EXAMINATION BY MR. SMITH:

Q. Can you briefly explain to me the difference in permitting statuses between the three Offshore Wind lease areas off if North Carolina.

A. (Ms. Gallagher) Um, yeah. Thanks. So Kitty Hawk, both North and South, are significantly more advanced than either of the Carolina Long Bay lease areas which were only just won this past May. Kitty Hawk has submitted both of its COPS for the North and the South. We're materially more advanced having purchased that lease area in 2017.

MR. SMITH: Thank you. Nothing further.

CHAIR MITCHELL: All right. With that, I will take motions.

MR. SMITH: I'd like to move that the prefiled summary of the Panel be entered in the record.

CHAIR MITCHELL: The summary of the prefiled testimony of the witnesses will be copied into the record as given orally from the stand at the appropriate time.

MR. SMITH: Yes. And then I would like -- oh. I would like my witnesses to be excused, but I know that we have to get more.

CHAIR MITCHELL: Okay. Let me take motions.

MS. LINK: May we move the admission of Duke Energy Avangrid Direct Cross-Examination Exhibits 1 and 2.

CHAIR MITCHELL: Hearing no objection, motion's allowed.

(Whereupon, Duke Energy Avangrid Direct Cross-Examination Exhibits 1 and 2 were admitted into evidence.)

MS. LINK: Oh, and subject to being --

CHAIR MITCHELL: They'll be supplemented.

MS. LINK: Supplemented.

CHAIR MITCHELL: Correct, with the correct versions or with the complete version.

MS. LINK: Okay. Perfect. Thank you.

MR. CONANT: Chair Mitchell, I'd like to move the CIGFUR Avangrid Panel Direct Cross-Examination Exhibit 1 be admitted into the record at the appropriate time.

CHAIR MITCHELL: All right. Hearing no objection, your motion's allowed.

(WHEREUPON, CIGFUR II & III Avangrid Panel Direct Cross-Examination Exhibit 1 was admitted into evidence.)

CHAIR MITCHELL: You-all may step down and be excused. Thank you very much for your testimony today.

THE WITNESS: (Mr. Starrett) Thank you.

THE WITNESS: (MS. Gallagher) Thank you.

CHAIR MITCHELL: All right. Mr. Neal.

MR. NEAL: Chair Mitchell, at this time, Southern Alliance For Clean Energy, et al. and jointly with the North Carolina Sustainable Energy Association, we call Uday Varadarajan to the stand.

CHAIR MITCHELL: All right. Good afternoon. Do you prefer to be sworn or affirmed?

MR. VARADARAJAN: Sworn.

CHAIR MITCHELL: Raise your right hand.

UDAY VARADARAJAN;
having been duly sworn,
testified as follows:

DIRECT-EXAMINATION BY MR. NEAL:

Q. Please state your name, title, and business address for the record.

A. Uday Varadarajan. I'm a Principal at RMI and a Precourt Scholar in Stanford. My business address is 1111 Broadway in Oakland, Carolina.

Q. And please briefly describe your role and

responsibilities at RMI?
A. I lead the Utility Transition Finance Team at RMI.
Q. Mr. Varadarajan, did you cause to be prefiled in this docket, on September 2nd, direct testimony consisting of 20 pages?
A. I did.
Q. Do you have any changes or corrections to your prefiled direct testimony at this time?
A. I do not.
Q. If the questions put to you in your testimony were asked at the hearing today, would your answer be the same?
A. Yes.
Q. Do you have any exhibits to your testimony?
A. Yes, I do.
Q. And were those prepared by you or under your direction?
A. Yes, they were.
Q. And did you prepare a summary of your testimony?
A. I did.

MR. NEAL: Chair Mitchell, I'd move to the Mr. Varadarajan's prefiled direct testimony and summary entered into the record as though given orally from the stand, and to have the exhibits attached to his prefiled direct testimony identified as premarked.

CHAIR MITCHELL: All right. Hearing no objection, your motion's allowed.

(WHEREUPON, Exhibits UV-1 and UV-2 are marked for identification as prefiled.)

(WHEREUPON, the prefiled direct testimony and summary of UDAY VARADARAJAN is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
	)	
Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plan and Carbon Plan	)))))	**DOCKET NO. E-100, SUB 179**

DIRECT TESTIMONY AND EXHIBITS OF

DR. UDAY VARADARAJAN

ON BEHALF OF

NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION, SOUTHERN ALLIANCE FOR CLEAN ENERGY, NATURAL RESOURCES DEFENSE COUNCIL, AND THE SIERRA CLUB

September 2, 2022

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UV-1	Resume of Dr. Uday Varadarajan
UV-2	RMI *Supplemental Report: Analyzing the Ratepayer Impacts of Duke Energy's Carbon Plan Proposal and Synapse's Alternative Scenarios*, report (September 2, 2022)

I. Introduction

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

A. My name is Uday Varadarajan. My business address is 1111 Broadway, Oakland, CA 94607. I lead the Utility Transition Finance Group at RMI.

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

A. I received an AB in Physics from Princeton University and an MA and PhD in Physics from the University of California, Berkeley. After graduation, I was a postdoctoral fellow in theoretical physics in the Weinberg Theory Group at the University of Texas at Austin. I subsequently became an AAAS Science and Technology Policy Fellow at the U.S. Department of Energy (DOE) and was on detail to the staff of the U.S. House of Representatives, Appropriations Committee. I then served as a program examiner in the U.S. White House Office of Management and Budget (OMB), where I oversaw the budget for DOE energy efficiency and renewable energy programs and the cost assessment and approval of the first $8 billion in DOE loans to automakers, including loans to Tesla and Nissan to build electric vehicles. My resume is attached to this testimony as Exhibit UV-1.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A. I am a Principal at RMI's Carbon-Free Electricity practice and a Precourt Energy Scholar at Stanford University's Sustainable Finance Initiative

(SFI), conducting financial, policy, and regulatory analysis to help drive a just transition to clean energy. Before joining RMI and Stanford, I was a Principal at Climate Policy Initiative Energy Finance (CPI-EF), where I managed CPI-EF's San Francisco team. At CPI-EF, I led the development of financial, regulatory, and policy data analytics and tools to help consumers, utilities, and communities in states across the United States (including New York, Colorado, Missouri, Minnesota, and Utah) realize the benefits of a just and equitable transition from uneconomic dirty resources to clean energy—with a focus on the potential benefits of ratepayer-backed bond securitization.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. At RMI, I lead the Utility Transition Finance group, a team of approximately 15 staff that performs financial, policy, and regulatory analysis to help drive a just transition to clean energy.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. No, I have not previously testified before the North Carolina Utilities Commission (hereafter, the Commission). I have testified before the Iowa Utilities Board (Docket RPU-2019-0001), the South Carolina Public Service Commission (Docket 2017-207-E, 9-24-2018 & 10-29-2018), the Minnesota Public Utilities Commission (Docket E015/GR-16-664, 05-31-2017 & 06-29-2017), and the Colorado Public Utilities Commission (Docket 16A-0231E, 10-3-2016 & 10-25-2016).

II. Purpose

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present and explain results of an analysis of the ratepayer impacts of Duke Energy's ("Duke") proposed Carbon Plan and to compare those ratepayer impacts to those found in the alternative portfolios modeled by Synapse. This analysis was conducted using Optimus, RMI's utility financial modeling tool, and was performed under my supervision by RMI staff. I will also offer my opinion on the potential impact of the Inflation Reduction Act (IRA) on the economics of North Carolina's energy transition.

III. Summary

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

A. RMI's analysis indicates that Duke's proposed Carbon Plan does not represent the least-cost path to North Carolina's carbon emission reduction requirements under H951. An alternative portfolio that invests more aggressively in the near term in energy efficiency and zero-emitting resources—such as solar, wind, and battery storage—would be cheaper for ratepayers and better insulate ratepayers from the cost impacts of future fuel price spikes as well as unexpected increases in electricity demand and from certain implementation effects of the multi-year rate plan (MYRP) provisions of H951.

Using Optimus, a modeling tool developed by RMI and described more fully in the reports submitted in this docket,[1] RMI analyzed two alternatives to Duke's proposed Carbon Plan (as emulated by Synapse Energy Economics in its "Duke Resources" scenario):

1) an "Optimized" scenario that modifies the characteristics of the Duke Resources portfolio to include annual incremental utility energy efficiency savings of 1.5% of total retail electricity sales, shorter gas plant book lives, external estimates for nuclear and gas capital costs, and National Renewable Energy Lab projections for renewables and battery storage costs; and
2) a "Regional Resources" scenario that is the same as the Optimized scenario except that it also allows EnCompass to select Midwest wind resources procured via power purchase agreements through the PJM Interconnection (PJM).

The key insights of this analysis are presented below:

1) The Optimized and Regional Resources scenarios are both more cost-effective than the Duke Resources scenario, driven by savings from avoided gas and nuclear investments.
2) Both alternatives to the Duke Resources scenario yield lower aggregate bills, with the Regional Resources scenario resulting in the greater bill reduction, even when disaggregated between DEC and DEP (the "Companies").
3) The Duke Resources scenario would exacerbate rate disparity between DEC and DEP customers, whereas the Optimized and Regional Resources scenarios would mitigate the rate disparity between the Companies and better distribute the ratepayer cost across the region.

[1] See RMI, "Analyzing the Ratepayer Impacts of Duke Energy's Carbon Plan Proposal," report Prepared for North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, Natural Resources Defense Council, and the Sierra Club (July 15, 2022); and Uday Varadarajan, *et al.* "Supplemental Report: Analyzing the Ratepayer Impacts of Duke Energy's Carbon Plan Proposal and Synapse's Alternative Scenarios," report Prepared for North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, Natural Resources Defense Council, and the Sierra Club (September 2, 2022), Attached as Exhibit UV-2.

4) The Duke Resources scenario is more vulnerable to execution risks, such as fuel price shocks, than the Optimized and Regional Resources scenarios.

IV. Discussion

b. *Sub-issues under topic "Coal unit retirement schedule; securitization"*

Q. WHAT ARE THE KEY FINDINGS IN RMI'S ANALYSIS REGARDING DUKE'S PROPOSED COAL UNIT RETIREMENT SCHEDULE AND PLANS FOR SECURITIZATION?

A. The Duke Resources scenario underutilizes securitization as a source of ratepayer relief to mitigate rate spikes from early retirement of coal. Securitization is a low-cost refinancing mechanism that yields savings for ratepayers when applied to larger unrecovered balances. The later a coal retirement occurs (assuming no further investment in the unit), the smaller the potential savings that can be derived from securitization. RMI estimates that the Duke Resources scenario would result in approximately $14.1 million in savings from securitization for ratepayers as a net present value (NPV) in 2022 dollars. For information purposes, RMI also modeled the securitization of 50% of all unrecovered balances following a retirement of all subcritical Duke coal plants at the end of 2022 and estimated an additional $446 million in savings (NPV, 2022 dollars) for ratepayers. From this perspective, the Duke Resources scenario captures only 3% of the ratepayer savings available from securitization under H951. To illustrate the magnitude of the potential for savings available with securitization, RMI also modeled a securitization scenario outside the limits of H951. If all unrecovered balances from all Duke coal plants, including the supercritical Cliffside 6 and the recently retired G.G.

Allen units, were securitized at the end of 2022, ratepayer savings from such a refinancing could reach $1.26 billion (NPV, 2022 dollars).

Q. HOW MIGHT THE RECENTLY PASSED IRA AFFECT THE ABILITY OF NORTH CAROLINA'S RATEPAYERS TO BENEFIT FROM LOW-COST REFINANCING OF THE UNDEPRECIATED BALANCE OF UNECONOMIC COAL PLANTS?

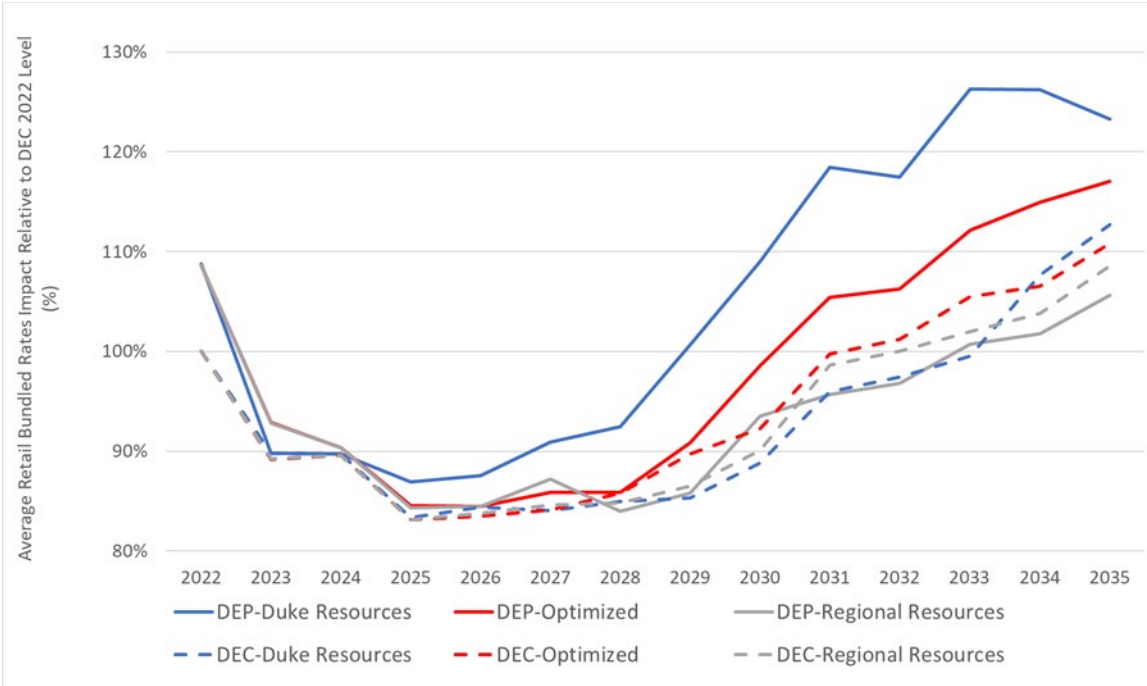
A. The IRA establishes a new Title 17 loan program at the U.S. Department of Energy known as Section 1706. The Section 1706 provision opens the way for low-cost financing for fossil asset transition without the restrictions on securitization in H951, in particular the 50% limit on retired plant balances eligible for securitization. With Section 1706, plant balances could be refinanced in full using debt backed by the guarantee of the federal government with interest rates similar to, and potentially lower than, those achievable with securitization, and over longer tenors (up to 30 years). As with securitization under H951, ratepayer savings under Section 1706 would tend to increase in line with the size of the plant balances refinanced and duration of the refinancing period, with earlier retirements yielding larger consumer benefits. Further, Section 1706 provides authority to extend the low-cost financing to environmental remediation, replacement with clean energy resources, and community reinvestment. This authority—which authorizes loan guarantees to support up to $250 billion in financing—could substantially reduce the cost of capital for more aggressive clean energy deployment scenarios, if utilized prior to its expiration toward the end of 2026.

g. *<u>Sub-issues designated under the topic "Rate Disparity / Merger / State Alignment"</u>*

Q. WHAT ARE THE KEY FINDINGS IN RMI'S ANALYSIS REGARDING DIFFERENT RATE IMPACTS FOR CUSTOMERS OF DEP AND DEC?

A. The overall rate impacts in 2030 relative to 2022 in the Duke Resources scenario show a similar level of disparity between DEC and DEP as that seen in Duke's Carbon Plan analysis. DEP customers see a larger average rate impact in 2030 than DEC customers from the Duke Resources scenario across all customer classes. Duke's proposed plan would thus significantly exacerbate rate disparity between DEC and DEP customers. In contrast, the Optimized and Regional Resources scenarios have lower rate and bill impacts across customer classes. Moreover, both scenarios significantly mitigate the rate disparity between DEC and DEP relative to the Duke Resources scenario. Therefore, the alternative scenarios help bridge the gap between the two utilities and better distribute the ratepayer cost across the region. Figure A below illustrates the rate disparity trends.

Figure A. Average Retail Bundled Rate Impact, DEP and DEP Respectively.



As explained more fully in the Supplemental Report,[2] the EnCompass modeling performed by Synapse of the Duke Resources, Optimized, and Regional Resources portfolios included the spike in natural gas prices that has occurred since the Russian invasion of Ukraine earlier this year. As a result, the Optimus model starts with higher retail bills across all scenarios (when compared to Duke's modeling[3]), which later drop as gas prices return to pre-invasion trends by 2025.

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[2] Supplemental Report, p. 17; this explanation is consistent with results shown in RMI's first report. See Analyzing the Ratepayer Impacts of Duke Energy's Carbon Plan Proposal, p. 11.

[3] Duke, Carolinas Carbon Plan, Chapter 3 – Portfolios, Table 3-3: Summary of Portfolio Results, p. 20.

i. *<u>Sub-issues under the topic “Cost” and i(v) “Factual issues related to all-in total cost and rate impacts for customers”</u>*

Q. WHAT ARE THE KEY FINDINGS OF RMI’S ANALYSIS REGARDING “ALL-IN COST AND RATE IMPACTS FOR CUSTOMERS”?

A. Investments in new nuclear and gas units are the primary drivers of the total ratepayer cost increase in the Duke Resources scenario throughout the planning period. Near-term investment in gas capacity also exposes ratepayers to significant risk through investment in assets that will either need to be converted to hydrogen (at costs that are highly uncertain today as the technology has not yet been deployed at scale) or will be obsolete before they are fully depreciated.

The Optimized scenario yields lower aggregate bills for Duke’s customers than the Duke Resources scenario. The savings are primarily driven by avoidance of new gas and nuclear buildout. Battery storage is the main driver of additional cost, but it is more than offset by the cost savings.

The Regional Resources scenario is even more cost-effective than the Optimized scenario relative to the Duke Resources scenario *in every single year*. Wind PPAs coupled with battery storage deployment are far more cost-effective than the fossil and nuclear investments made in the Duke Resources scenario.

k. *<u>Sub-issues under the topic “Execution Risks”</u>*

Q. CAN YOU ADDRESS THE LEVEL OF EXECUTION RISKS POSED BY THE VARIOUS SCENARIOS?

A. Compared with Optimized and Regional Resources scenarios, the Duke Resources scenario is more vulnerable to execution risks, including fuel price shocks, higher demand, and the implementation of H951's MYRP provisions.

Q. IN YOUR OPINION, WHAT IS THE MOST SIGNIFICANT EXECUTION RISK FOR THE CARBON PLAN?

A. Any resource scenario modeled under the policy framework that existed before the passage of the Inflation Reduction Act (IRA) on August 12, 2022, will not reflect the potential for enormous savings for North Carolina ratepayers from IRA policies. This is particularly true for portfolios that rely on new gas generation or keep coal plants running past their economically optimal retirement dates in place of non-carbon emitting resources such as solar, wind, and battery storage, which are all eligible for hundreds of billions of dollars in new and expanded federally funded incentives and key regulatory improvements (such as the provision for regulated utilities to opt-out of the requirement for tax normalization for ratemaking purposes of the Investment Tax Credit (ITC) for certain storage technologies, including battery storage). This new policy framework has the potential to radically alter the cost-effectiveness of clean resources, reduce the cost of retiring of fossil assets, and change incentives for ownership structures of clean resources.

Q. CAN YOU DESCRIBE IN MORE DETAIL THE MOST IMPORTANT PROVISIONS OF THE IRA DESIGNED TO INCENTIVIZE THE

DEPLOYMENT OF CLEAN ENERGY RESOURCES SUCH AS WIND, SOLAR AND BATTERY STORAGE?

A. Yes. The IRA includes approximately $370 billion in federal funding and tax benefits to advance climate and energy goals.[4] Foremost, the IRA provides a full decade (and, potentially, a longer period) of tax-credit certainty for solar, wind, and storage technologies. The existing 10-year Production Tax Credit (Section 45) is expanded to include solar as well as wind and extends credit eligibility at full value for projects deployed through the end of 2024. The existing Investment Tax Credit (Section 48) is continued at full value through the end of 2024 and now includes stand-alone energy storage projects. Notably, regulated public utilities may now opt-out of “tax normalization” of the ITC for ratemaking purposes, albeit for storage investments only, removing a federal legal barrier that has disadvantaged pricing (as flowed-through to customers) for utility-owned assets compared with technologically identical third-party-owned offerings. If newly implemented prevailing wage and apprenticeship “bonus” requirements are satisfied, the PTC for wind and solar is $26 per MWh (in 2022$), while the ITC is sized at 30% of project cost.

After 2022, an adder of 10% for the PTC and 10 percentage points for the ITC will apply if specific domestic materials requirements are met (phased in initially at 40%, though only 20% for offshore wind projects, and

[4] Committee for a Responsible Federal Budget, “What's In the Inflation Reduction Act?,”(12 August 2022), accessed on 17 August 2022 at https://www.crfb.org/blogs/whats-inflation-reduction-act.

rising to 55% for onshore projects beginning construction in 2027 or later and offshore projects beginning construction in 2028 or later). Relatedly, Section 50251(a) of the IRA authorizes the Secretary of the Interior to issue renewable energy leases, easements, and rights-of-way in areas of the outer continental shelf off the coast of North Carolina (and several other southeastern states) that were placed under a leasing moratorium by former President Trump for the period from July 1, 2022, through June 30, 2032.

The IRA also provides an ITC and PTC enhancement for projects placed in service within an "energy community" defined to include brownfield sites; a census tract or any adjacent census tract in which a coal mine has closed after 1999, or a coal-fired electric generating unit has been retired after 2009; and a metropolitan or nonmetropolitan statistical area that (1) at any time after 2009 has had at least 0.17% direct employment or 25% local tax revenues from the extraction, processing, transport, or storage of coal, oil, or natural gas and (2) had an unemployment rate at or above the national average for the previous year, in each case as determined by the Secretary. Assuming the prevailing wage and apprenticeship requirements are met, the amount of the base PTC is increased by 10% and the amount of any ITC is increased by 10 percentage points (or 2% and 2 percentage points, respectively, if the wage and apprenticeship requirements are not satisfied).

Since the bonuses and adders are stackable, a PTC project garnering them all would receive $31 per MWh (2022$) produced each year for ten years, while an ITC project would receive a 50% tax credit upon entering service.

Furthermore, the IRA addresses the issue of taxpayer "tax capacity" by allowing transferability, which will facilitate more cost-effective utilization of the expanded credits regime. Transferability—which allows taxpayers to sell their tax credits to an unrelated party—provides a more efficient way to monetize the present value of the tax credits. Prior to the enactment of the IRA, taxpayers without sufficient income-tax liability to self-monetize credits had to either (a) rely on expensive tax equity financing or (b) carry forward deferred tax assets on their own balance sheets with corresponding losses due to the time value of money. For tax exempt entities and Subtitle T electrical cooperatives, the IRA allows direct pay (cash refundability) of the credits.

For the period after 2024, the IRA creates a new technology-neutral 10-year clean energy PTC (Section 45Y) and maintains this credit in full for projects that begin construction by the later of either (a) 2032 or (b) the year that electric power sector emissions are equal to or less than 25% of 2022 electric power sector CO_2 emissions. A three-year phase-down of the credit level follows the relevant trigger year, with projects beginning construction in the first year of the phase-down period still eligible for 100% of the credit, which then reduces to 75% and 50% of full value over the next two years.

The bonus and adders are available as before. A new technology-neutral clean energy ITC (Section 48E) is also in the legislation with the same phase-down terms at the new PTC.

Combined with ITC eligibility for stand-alone energy storage projects and the normalization opt-out for ratemaking treatment of the storage ITC, these transferable credits will significantly reduce the costs of utility-supplied wind and solar energy, making these resources relatively more economic in the near and medium term. From 2025 onward, SMRs will also be eligible for the technology-neutral credits. But the future costs of mature technologies like wind and solar are reliably forecasted today, and credits will shift costs lower in predictable fashion. For still unseasoned technologies like SMRs, baseline asset costs and output levels for purposes of estimating the value of production credits are highly speculative.

Q: CAN YOU PROVIDE A TABLE SUMMARIZING TAX MEASURES UNDER THE IRA COMPARING THEM WITH THE POLICY LANDSCAPE BEFORE THE PASSAGE OF THIS IMPORTANT LEGISLATION?

A. Yes. The Table A below offers such a summary and comparison.

Table A. Comparison of Key Elements of Policy Environment before and after passage of the IRA

Policy	Pre-IRA	IRA
Production Tax Credit (PTC) for solar	Not available	Yes
Availability of PTC	Beginning of construction by end of 2021, with 4-year safe harbor for completion by end of 2025 (10-year safe harbor for offshore wind)	Beginning of construction in 2032 (or later if emissions reduction targets not achieved), followed by three-year phase-down of credit level
Duration of Investment Tax Credit (ITC)	For onshore wind: beginning of construction by end of 2021, with safe harbor for completion by end of 2025 For offshore wind: beginning of construction by end of 2025 For solar: placed in service by the end of 2025 to receive more than credit of 10% available without sunset	Beginning of construction in 2032 (or later if emissions reduction targets not achieved), followed by three-year phase-down of credit level
PTC level for wind and solar	For wind: phase-downs for projects begun after 2016, for instance 60% of full credit for projects begun in 2020 and 2021. For solar: not available	$26 per MWh (2022$) for ten years (inflation adjusted), if wage and apprenticeship requirements met
ITC level for wind and solar	For onshore wind: phase-downs for projects begun after 2016, for instance 60% of full credit for projects begun in 2020 and 2021 For offshore wind: 30% for projects that begin construction by the end of 2025 For solar: 26% for project that began construction in 2020, 2021 or 2022, and	30%, if wage and apprenticeship requirements met

	22% for projects starting construction in 2023. Projects must be placed in service by the end of 2025 to receive a credit higher than 10%	
ITC level for stand-alone storage	Not available	30%
Domestic content adders (may be stacked on top of PTC or ITC)	Not available	Up to 10% for PTC or 10 percentage points for ITC
“Energy Communities” adders (may be stacked on top of PTC or ITC)	Not available	Up to 10% for PTC or 10 percentage points for ITC
Low-income ITC adders for solar and wind (may be stacked on top of ITC)	Not available	Up to 20% for eligible installations of 5 MW in size or smaller, subject to annual nationwide 1.8 GW capacity cap
Direct pay of PTC and ITC for tax-exempt entities and all rural electricity co-ops and transferability of these credits for taxpayers	Not available	Yes
Normalization opt-out for storage ITC	Not available	Yes
Carbon capture and storage (45Q)	\$50 per metric ton for sequestered CO_2, a level to be attained by 2026, available for 12 years, inflation adjusted. Projects must begin construction by end of 2025	\$85 per metric ton for sequestered CO_2 if wage and apprenticeship requirements are met, a level to be attained by 2026, available for 12 years, inflation adjusted; projects must begin construction by end of 2032
Existing nuclear (45U)	Not available	With wage and apprenticeship requirements met, \$15 per MWh, but is reduced when average annual price exceeds \$25 per MWh; available through 2032

Clean hydrogen (45V)	Not available	Maximum $3 per kg (2022$), available for 10 years, inflation adjusted. May be combined with PTC for wind and solar and 45U for existing nuclear
Securitization and low-cost refinancing	NC H951 allows for securitization of 50% of retirement balances of subcritical coal plants	Federally backed refinancing for fossil assets (no balance limitation), replacement with clean resources, environmental remediation, and community reinvestment under Section 1706

Q: HOW MIGHT THE IRA IMPACT NORTH CAROLINA'S TRANSITION TO CLEAN ENERGY?

A: In my opinion, any future resource portfolio developed for North Carolina ratepayers using clean energy asset costs estimated without considering the IRA's provisions should be reevaluated to see if reliable transition pathways that are both cheaper and cleaner are feasible. I wish to emphasize that the IRA's provisions are designed to impact not only investment decisions later in this decade, but ones that are of pressing urgency today. Without considering the wide-ranging impacts of the IRA, the Commission risks selecting a near-term strategy for reaching the statutory carbon requirements that locks in extra costs for ratepayers and leaves savings opportunities untapped. As a result of the passage of the IRA, portfolios that rely in the short to medium term on new gas plants or on extending the operation of coal plants are going to be even more costly in comparison to portfolios that rely more heavily on efficiency, solar, battery storage, and wind.

Q. DID YOU IDENTIFY ANY HEIGHTENED EXECUTION RISKS ASSOCIATED WITH DUKE'S PROPOSED CARBON PLAN BEFORE THE IRA WAS PASSED AND WHICH ARE NOT DEPENDENT ON THAT LEGISLATION'S NEW AND EXPANDED INCENTIVES FOR CLEAN ENERGY TECHNOLOGIES?

A. Yes. Compared with the Duke Resources scenario, the Optimized and Regional Resources scenarios help to:

- insulate ratepayers from the risks of fuel price shocks.
- mitigate the cost risks to customers from inadequate system planning for the impacts of a rapidly electrifying economy.

Q. DO MYRPS AFFECT EXECUTION RISK?

A. The implementation of MYRPs and revenue decoupling for the residential class as specified by H951 would exacerbate the rate impact of higher-than-expected demand and fuel prices relative to a scenario without these mechanisms in place. In all scenarios, the MYRPs in N.C. Gen. Stat. § 62-133.16 result in higher average bills for ratepayers; however, the cleaner and lower-cost Optimized and Regional Resources scenarios better mitigate some of the bill increases.

Q. WHAT ARE RMI'S RECOMMENDATIONS FOR THE CURRENT CARBON PLAN PROCESS TO MITIGATE EXECUTION RISK ASSOCIATED WITH FUEL PRICE SHOCKS, HIGHER DEMAND, AND THE APPLICATION OF PERFORMANCE-BASED REGULATION?

A. RMI recommends that the Commission take under consideration before determining North Carolina's Carbon Plan:

1) the potential recurrence of destabilizing macro-economic and socio-political disruptions, such as those that the global economy has experienced in the last two years, and the downstream impacts these events may pose to ratepayers - collectively, and by class - under various Carbon Plan

proposals (e.g., the risks associated with increasing and potential volatile fuel costs, and uncertain fuel availability);

2) the potential impacts on the distribution of benefits and risks that are associated with forthcoming coming regulatory changes (e.g., PBR) in combination with each portfolio; and

3) the impact of a fully economic coal retirement schedule (such as a scenario that allows EnCompass to select the economic retirements without exogenous limitations) inclusive of and considering the associated benefits of securitization and other refinancing tools that are available under the IRA.

Q. WHAT ARE RMI'S RECOMMENDATIONS FOR THE CURRENT CARBON PLAN PROCESS TO MITIGATE EXECUTION RISK ASSOCIATED SPECIFICALLY WITH THE IRA?

A. To recapitulate, the passage of the IRA will significantly alter the cost of many clean energy technologies, making them far cheaper over the coming decade than was assumed in capacity expansion and production cost modeling conducted for the current Carbon Plan. For instance:

- the resource costs of solar, batteries, and wind will all be significantly lower with the extension and broadening of ITC and PTC;
- the availability of a solar PTC, which is not subject to tax normalization, and the normalization opt-out for the storage ITC, will increase the price competitiveness from a ratepayer perspective of utility-owned solar and storage assets relative to third-party owned assets;
- hydrogen production costs will be lower as a result of the Section 45V tax credits and, moreover, tax benefits will be greater for hydrogen that is produced with lower or zero lifecycle carbon emissions;
- EV costs and the costs of electrifying home space and water heating will be lower, which will impact load assumptions; and
- Section 1706 provides the potential for low-cost financing to reduce the rate impact of accelerated phase-out and replacement of fossil assets beyond the limitation of NC H951.

All of these changes impact the economics of resource selection, and consequently, the timing of CO2 reduction target feasibility. If production cost modeling were to be run today with the realities of the IRA reflected, scenarios with larger and more rapid deployment of mature clean energy resources than those currently before the Commission would likely be "least cost." The game-changing incentives of the IRA come into effect rapidly, and indeed, the critical changes for wind, solar, and battery are available today. Given this new policy reality, the IRA is of extreme relevance for near-term investment decisions and should be assessed accordingly for potential benefits that might accrue to North Carolina ratepayers and other stakeholders. The Commission should take whatever steps it can to ensure that Duke's near-term actions under the ultimate Carbon Plan reflect a no-regrets strategy from the perspective of the policies in the IRA.

Absent an effort to perform additional capacity expansion and production cost modeling in the near-term, any resource decisions, near-term execution plans, and relevant resource planning activity that occurs after the September 2022 Carbon Plan evidentiary hearing (including but not limited to the Commission's decision on the Carbon Plan and short-term execution plan, adjustments to the Carbon Plan, MYRP applications, and proceedings related to certification of public convenience and necessity) should include an analysis of the full scope of the IRA cost implications.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Summary of Testimony of Dr. Uday Varadarajan on Behalf of North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, Sierra Club, and Natural Resources Defense Council

Docket No. E-100, Sub 179

I am Dr. Uday Varadarajan, head of the Utility Transition Finance Group at RMI. I offer the following summary of my direct testimony.

As set forth in RMI's "Supplemental Report: Analyzing the Ratepayer Impacts of Duke Energy's Carbon Plan Proposal and Synapse's Alternative Scenarios," RMI conducted an analysis that compared the ratepayer financial impacts of Duke Energy's proposed Carbon Plan with the Optimized and Regional Resources scenarios modeled by Synapse Energy Economics. This analysis was offered to assist the North Carolina Utilities Commission in its selection of the least-cost path toward meeting the statutory requirements of HB 951.

Optimus allows RMI to provide a deeper analysis than the net present value revenue requirement estimates produced by EnCompass. Optimus estimates ratepayer impacts using the full revenue requirement, including all cost components of both existing assets and incremental resources added to the portfolio by EnCompass, as well as capital and operating costs associated with non-production assets. Importantly, Optimus allows RMI to conduct a forward-looking estimate of rates and bills differentiated by customer class for the various portfolios generated by EnCompass, taking into account Duke's cost of service methodologies. The key insights of this analysis are presented below:

1. The Optimized and Regional Resources scenarios are both more cost-effective than the Duke Resources scenario, driven by savings from avoided gas and nuclear investments.

2. Both alternatives to the Duke Resources scenario yield lower aggregate bills, with the Regional Resources scenario resulting in the greater bill reduction, even when disaggregated between DEC and DEP (the "Companies").

3. The Duke Resources scenario would exacerbate rate disparity between DEC and DEP customers, whereas the Optimized and Regional Resources scenarios would mitigate the rate disparity between the Companies and better distribute the ratepayer cost across the region.

4. The Duke Resources scenario is more vulnerable to execution risks, such as fuel price shocks, than the Optimized and Regional Resources scenarios.

RMI's Optimus analysis results indicate that Duke Energy's proposed Carbon Plan does not represent the least-cost path to North Carolina's emission reduction requirements. A portfolio that invests more aggressively in the near term in energy efficiency and zero-emitting resources—such as solar, wind, and battery storage—will better insulate ratepayers from the potential cost impacts of future fuel price spikes, performance-based regulation, and a future in which electricity demand is higher than anticipated.

The recently passed Inflation Reduction Act (IRA) has immediate and far-reaching consequences for the least-cost path toward North Carolina's carbon reduction requirements. The magnitude of the IRA—$370 billion in federal funding designed to deliver unprecedented cost savings for ratepayers while offering large-scale transition assistance for fossil energy workers and communities—has major implications for the results of capacity expansion and production cost modeling carried out before the legislation's passage. Although the IRA's precise impacts on potential carbon plan portfolios cannot be known without further analysis, the IRA is expected to make renewables and storage much more cost-competitive with gas in the near term. The IRA's tax credits and other provisions for wind, solar, and storage will bring down the costs of these market-ready and already cost-competitive resources, further reducing the cost of modeled portfolios that rely on clean energy resources relative to portfolios that include new gas and keep coal plants running past their economically optimal retirement dates.

Additionally, the IRA's Energy Infrastructure Reinvestment provision is available to provide up to $250 billion in low-cost, federally backed loans not only to refinance remaining balances for fossil assets (securitization), but also to reinvest in the fossil asset communities via replacement clean energy, environmental remediation, and redevelopment of the site into other productive uses that spur local economic opportunities. This program represents a more cost-effective and holistic approach to securitization and transition than what was enabled by H951 (e.g. there are no limitations on asset types, and loans can represent greater than 100% of remaining balances.)

If the IRA is not accounted for, North Carolina is at risk of selecting a near-term strategy for reaching the statutory carbon requirements that locks in extra costs for ratepayers and leaves savings opportunities untapped. In the meantime, the Synapse portfolios, by relying more heavily on technologies that will be made more affordable by the IRA, is more likely to provide a roadmap to a no-regrets short-term execution plan than the portfolios port forward by Duke Energy. Any resource decisions, near-term execution plans, and relevant resource planning activity that occurs after the September 2022 Carbon Plan evidentiary hearing should include an analysis of the full scope of the IRA's cost implications.

This Concludes my summary.

MR. NEAL: The witness is ready for cross examination and questions from the Commission.

CHAIR MITCHELL: All right. My notes indicate that we have up first CIGFUR.

MR. CONANT: Chair Mitchell, we'd waive.

CHAIR MITCHELL: Let's see. Brad Rouse.

MR. ROUSE: Yeah. Hi. I'm Brad Rouse, and I am pro se. I'm an intervenor and I am not a lawyer, so take that as you will.

CROSS-EXAMINATION BY MR. ROUSE:

Q. I just want to refer you to your testimony, page 19, the paragraph beginning with residential customers. And I'd be happy if you wanted to read or I can read it, just the first sentence.

A. Apologies. Page 19?

Q. That's what I've got. Here. Let me read it and you can save -- it says residential customers CA, 22 percent decrease in bills by 2030 compared with 22 in the Optimized scenario. A 25 percent decrease over this period in the Regional Resources scenario compared with a 16 percent decrease in the Duke Resources scenario. Is that your testimony?

A. That's correct, except I don't think I see the same page number, but that's fine.

Q. Okay. And so my first question with respect to that is did you assume in this analysis -- well, I understand you used the Optimus Modeling System. Is that correct?
A. That's correct.
CHAIR MITCHELL: All right. Let's get on the same page here so that we can get through this examination efficiently. I believe you're referring to page 19 of the witness' -- the exhibit to his testimony. Is that correct?
THE WITNESS: That's correct. I think so. Thank you.
MR. ROUSE: I'm sorry. Yeah.
CHAIR MITCHELL: Okay. I just want to make sure the witness is able to answer your questions. Okay. Go ahead.
Q. Yeah. So I've just got some questions about how you set up the analysis that was done. And one question is -- first of all, this is a projection of the rates, all-in costs included?
A. That's correct.
Q. Okay. And did you assume an underlying inflation rate?
A. Yes. There were underlying inflation rates that were built into the modeling, that's correct.
Q. So was there an overall underlying inflation rate or a general consumer price index inflation rate that was

assumed?

A. Yes. We used a projected CPI inflation rate based on inflation expectation taken from treasury temp spots.

Q. So would it be fair to say that the real reductions in costs that you're expecting under these three scenarios from 2022 are actually greater than the numbers if you were to say that in constant dollars?

A. That's right though. Of course the inflation expectations and analysis are dated now are ready.

Q. Well tell me about how its changed.

A. Only that inflation expectations have been moving very rapidly over the last few months. So relative to when the testimony was filed, they may have already changed significantly.

Q. Okay.

A. But the conclusion still holds.

Q. Okay. Now in your -- the way you refer to this in the sentence that I read, you referred to bills. Is that correct?

A. That's right. So the more appropriate statement is that we do include the impact of changes in expected load profile as well. That is the efficiency gains and the differences in load profile between the three different scenarios is accounted for. So we are looking at all-in

bills on average rather than just rates, so that's a more precise way to say what that number really is.
Q. So do you recall off-hand or could you tell me how much the decline was in energy consumption per customer over that period of time?
A. So this is just the difference between the Synapse assumptions and the assumptions that Duke use, so this is the one and a half percent relative to the 1 percent.
Q. For the Duke programs, but did you have an underlying decrease in usage for customers as well?
A. I believe that for -- and I'll need to check this and revise potentially, but I believe this was an assumption that we made for the -- for all of the -- for the full load production, if you recall correctly.
Q. But is it fair to say that you started with the Duke forecast?
A. We started with the Duke forecast and it was a more aggressive assumption in the Synapse analysis.
Q. Okay. So you would have the Duke assumptions then on -- beneficial electrification and electric vehicles and net metering embedded in solar -- home solar production embedded in all of that?
A. That's right.

Q. Okay. Do you have Duke's Carbon Plan summary available?
A. That I do not. Apologies.

MR. ROUSE: Could I show him Exhibit 1 of the Executive -- or Table 1 of the Executive Summary of the Carbon Plan?

CHAIR MITCHELL: You may approach.

(Handed)

Q. Okay. I don't have that in front of me now. In that, it shows the differential impacts of the portfolios from Duke. Is that correct?
A. That's right.
Q. And there's a second section about affordability and impact on bills. Do you see that section there?
A. Uh-huh (yes).
Q. And do you see the section where it says that in Portfolio 1, the bill for residential customers using 1000 kilowatt hours will go up by $35 in DEP and $8 in DEC? Do you see that?
A. I do.
Q. So would you agree that Portfolio 1 from Duke from this Executive Summary and the Duke Resources scenario that you're referring to from Synapse have the same resource expansion schedule in underlying energy forecast?

A. Yes. They attempted to get as close as they could. This is based on Synapse's run of Duke's portfolio, and there's some important differences that I'm happy to get into.
Q. So briefly, how can you reconcile that increase in bills with your 16 percent decrease in bills?
A. This is because we used an updated fuel price forecast for 2022 based on the geopolitical events that significantly shifted near-term gas price expectations and costs for this year. So the reductions are reflective of the fuel price shock that we're seeing in a way that wasn't possible for Duke to have done in its previous analyses. This is just a function of us having started the analysis later. That's why we really focus on the comparison between the scenarios rather than the absolute, but this is -- once we updated those cost forecasts, this is the result.
Q. Okay. Well would this also reflect the heightened -- theirs is a 1000-kilowatt hour fixed consumption, whereas you're looking at declining consumption also?
A. So theirs is normalized to reflect 1000-kilowatt hours of consumption. It does indeed matter that the average customer would indeed be using less. But again, it's a relatively smaller effect, but we do see an impact from

going from rates to bills.

Q. And are you aware that both the Duke plan referenced in Portfolio 1 and the Duke Resources Plan, and the other two plans that you also discussed, that have even greater cost reductions, do, in fact, all meet the 70 percent carbon reduction part in 2030?

A. Yes.

Q. So would you say that there's load shock involved in meeting that target, of rate shock involved in meeting that target?

A. So we also do look by customer class at the impacts, and across the utility subsidiaries, and the specific rate impacts or bill impacts for customers do vary across rate classes and across the two subsidiaries. In some cases, for some customer classes, particularly as we look at the Regional Resources scenario or the Optimized scenario, what we find is a significantly lower cost impact. And in some cases, indeed relative to this year, which, you know, again has been something, in and of itself, of an energy shock, we do indeed find rate impacts on a forward-looking basis that don't exceed what we expect or what we've seen this year.

And so from that point of view,

indeed relative to this year, no, we don't see that much of a rate shock. But again, you know, we can ask the question as to whether that's a fair assessment. There are indeed, for each of these scenarios over time, a decrease in rates relative to the rate shock, and then an increase at some point as the total cost of all the resources that are built in take effect. That being said, none of these scenarios incorporate at all any of the incentives that had just recently been passed in the IRA. And so from that point of view, just to your point, the rate shock that we're seeing is -- it is not at all unreasonable to expect that IRA would significantly reduce the rate impact that even we're seeing. And so the hope is that -- and maybe more than the hope, there is $370 billion dollars of incentives that are aimed at trying to ensure that any state and utility that attempts to significantly reduce its carbon emissions will have significant financial measures being offered by the government, and tax incentives being offered by the government that will mitigate that rate impact, substantially more than anything we have modeled so far.

Q. Great. Well --

MR. NEAL: Chair Mitchell, I hate to

interrupt Mr. Rouse, but given the time, can I inquire whether or not the Commission has questions before we run out of time in the day?

MR. ROUSE: I just have -- I have two more questions.

MR. NEAL: Thank you.

CHAIR MITCHELL: All right. Mr. Rouse, proceed with your cross-examination.

BY MR. ROUSE:

Q. So I'm not going to go into all the details of the IRA because that's obviously beyond what we can talk about here. Would you say that the -- let talk just about the major impacts. Would you say that the production tax credit for nuclear is the biggest impact on Duke's rates?

A. I would argue that on a forward-looking basis, there are three other programs that may have more significant impacts. I would expect that the shift in tax normalization rules for storage and the ability to take the PTC in lieu of the ITC for solar are likely to potentially, significantly reduce the cost of any utility-owned solar and storage assets. And given the significant prominence in virtually all the scenarios in the next several -- in the next decade of solar and storage, those two measures will, in particular, reduce the cost along with the possibility of transferability of tax credits, will reduce the cost of utility-owned solar and storage significantly.

And the other piece I will mention, I know there's been quite a bit of discussion of transmission upgrades and the challenges of interconnection, there's a little-known program in the IRA called the Title 17-1706 Loan Program. And this loan program is an energy infrastructure reinvestment program. It is very broadly defined, but what it provides is very low-cost financing that in particular, can be aimed at Brownfields and transmission to allow re-powering infrastructure upgrades at a much lower cost of capital than a private sector entity can afford. Now, of course you wouldn't fund the whole thing with government financing, but it's $250 billion dollars in lending authority at treasuries plus 37.5 basis points that is available to significantly mitigate the cost and risks associated with reinvesting in Brownfields, and for reconductoring or performing other network upgrades that are intended to integrate clean energy.

And I would argue that these

provisions, particularly given some of the challenges and risks that I've been hearing through this proceeding, could be more impactful in many ways than some of the more obvious provisions. And I'd say the most obvious is just the extension of all of those tax credits, but these are really important to keep in mind.

Q. Okay.

MR. ROUSE: That's all my questions. Thank you.

THE WITNESS: Thank you.

CHAIR MITCHELL: All right. I don't have any cross-examination indicated for the witness, but just checking in to make sure that is the case. Do you have cross-examination for the witness?

MR. FREEMAN: No.

CHAIR MITCHELL: Okay. Any redirect for the witness?

MR. NEAL: No, Chair Mitchell.

CHAIR MITCHELL: Okay. Let me see if there are questions from Commissioners. All right. I have just have one for you.

EXAMINATION BY CHAIR MITCHELL:

Q. What I'm hearing you say is there are opportunities, some of which are sort of well-known and understood like, the tax credits. The production tax credits are investment tax credits. And then there are lesser-known programs that are available that could off-set or absorb some of the costs associated with the work that Duke is going to do going forward as a result of 951. Did I understand your testimony correctly?

A. That's absolutely right. There are a number of provisions that have been designed specifically to address some of the challenges that regulated utilities and their are customers have faced in building clean energy. We've had tax incentives that have been put in place that largely didn't work for most of the utilities that own coal or fossil assets across the country, that disadvantaged them effectively in taking advantage or discouraged them from taking advantage of these tax credits.

And some of those issues have been substantially fixed in the IRA and there are programs like the Energy Infrastructure Reinvestment Act, lending programs that essentially provide financing to specifically address the opportunities for reinvestment in systems that have hosted significant fossil generation in the past, and that should mitigate

the cost of repurposing them for clean energy, so yes.
Q. Okay. Thank you for that, and I appreciate your testimony on the changes and the tax -- the applicability or the usability of the tax credit by the utilities. And I am not a tax expert, so I won't ask you to explain that to me. I'm just going to accept your testimony as it is. In your work with your client in this docket, in any discovery or discussions with the utilities that you have been a part of, is there anything -- are you aware of anything or any information from the utilities that would lead you to believe they're not doing everything they can do to take advantage of these -- of favorable tax treatment or federal -- the availability of federal funds to mitigate some of the -- put pressure on cost?
A. So all I've seen, unfortunately, is just the late-filed testimony indicating an approach to incorporating the IRA, the Company took. What I do see there is reflected -- I do see reflected the extension of some of the tax credits. I don't necessarily see nor would I've necessarily expected to see discussion of the tax normalization issue. They're used potentially of the transferability necessarily discussed, nor of the Energy Infrastructure Reinvestment Act. So I think

these are areas that are -- were relatively obscure in the Act.

I would also point out I don't yet see a deep discussion of the commercial incentive for electric vehicles and for electrification, fleet electrification. These are all incentives that I think could be very, very substantial in terms of its impact in North Carolina.

Q. Okay. And Duke witnesses that have appeared on direct testimony have testified that there's still much to learn about particularly the IRA, and I heard -- and I'm hoping you had the opportunity to listen to them, but I heard that there were -- that they anticipate private letter rulings and other regulatory action coming out of the federal government before they'll have a full picture of the availability of credits or funds. Is that an unreasonable -- do you think that's an unreasonable position for the Company to have at this point in time, given what you know about the IRA?

A. I think the rulings are indeed coming. We expect that they will be happening in the next six months. I do think that the opportunities are large enough that there is significant risk to the Company and to the state not to be anticipating what those rulings might be, and to be moving quickly to take advantage of some of these provisions, not all of which are available indefinitely.

Q. Okay.

CHAIR MITCHELL: All right. I appreciate your testimony. I'm checking in to see if there are any questions on Commissioners' questions. All right.

MR. NEAL: Yes, briefly.

EXAMINATION BY MR. NEAL:

Q. Doctor Varadarajan, following up on Chair Mitchell's questions about provisions in the IRA that haven't yet been considered by Duke, and what you've seen so far, are there also -- can you comment on the provisions related to home energy efficiency upgrades, heat pumps, heat pump hot water heaters and the like?

A. Yeah. I would note that RMI has recently put out some analysis that it expects that there could be as much as on the order of 1 to 2 million new heat pumps that are incentivized by the tax credits that are now provided in the IRA, in the near term and similarly, there has been a reduction or an elimination of the cap for home energy retrofit tax credits and tax credits benefits across the board. There are also rebate programs that we anticipate will take longer to execute, but should make available substantial rebates, particularly for low-income customers. That could provide them up to $14,000 in upfront benefits to address home energy-efficient easy needs, including Panel upgrades and other challenges to electrification.

The net result of all of this should be potentially, significantly greater opportunities for customer-driven energy-efficiency retrofits as well as ones that are assisted by a utility. And the combination of these are likely to have -- start having an impact as soon as early next year with the tax credits, probably with like somewhere between 12 and 24 months for the state and local-driven rebates for low-income customers.

MR. NEAL: Thank you. No further questions.

CHAIR MITCHELL: All right. I'll take motions.

MR. NEAL: Thank you. Chair Mitchell, at this time, we would move to admit Exhibits UV-1 and UV-2 into the record.

CHAIR MITCHELL: All right. Hearing no objection, that motion will be allowed.

(WHEREUPON, Exhibits UV-1 and UV-2 were admitted into evidence.)

CHAIR MITCHELL: You may step down. Thank you very much for your testimony today, and you're excused. With that, we are very close to the end of this day. I see Mr. Jimenez. Would you like to come up and make your motion, please, sir.

MR. JIMENEZ: Thank you, Madam Chair. I was informed by Commission Staff that the Commission would entertain a renewed motion to enter Mr. Caspary's report. I'd like to make that motion at this time. SACE, et al. moves to enter, at the appropriate time, the report of Mr. Jay Caspary entitled, "Transmission Issues and Recommendations for Duke's Proposed Carbon Plan" consisting of 19 pages, including its Attachment A and verification filed in Docket No. E-100, Sub 179 on July 15th, 2022 as Exhibit 2 to the joint comments of SACE, et al. and NCSEA.

CHAIR MITCHELL: All right. Hearing no objection to the motion, it be allowed.

(WHEREUPON, SACE, et al. Caspary Report is admitted into evidence.)

MR. NEAL: Then Chair Mitchell, I should probably also make a similar motion for Exhibit 1 of those same comments, which was an RMI report analyzing the ratepayer impacts of Duke Energy's Carbon Plan proposal.

CHAIR MITCHELL: Hearing no objection, your motion's allowed.

(WHEREUPON, SACE, et al. RMI Report is admitted into evidence.)

MR. NEAL: Thank you.

CHAIR MITCHELL: Mr. Snowden.

MR. SNOWDEN: Chair Mitchell, CPSA calls Ryan Watts to the stand.

CHAIR MITCHELL: Mr. Snowden, I was under the impression that -- I had been informed that you were prepared to make a motion to waive the witness?

MR. SNOWDEN: Well, yes, ma'am. I'll say this. So CIGFUR, who was the only party that had reserved cross time, they have waived cross. If the Commission has questions for Mr. Watts, I'm happy to put him up and answer any Commission questions. If the Commission does not have questions for Mr. Watts, then I would ask to excuse him.

CHAIR MITCHELL: Okay. It's my understanding the Commission does not have questions for the witness.

MR. SNOWDEN: Then I would ask that Mr. Watts be excused and that his prefiled testimony and exhibits be moved into the record, as well as his summary.

CHAIR MITCHELL: The motion's allowed. The witness' testimony will be copied into the record as if delivered orally from the stand. Exhibits will be identified, marked for identification as they were when prefiled, accepted it into evidence, and the summary of his testimony will be copied into the record at the appropriate time as well, and the witness is excused.

(WHEREUPON, Watts Exhibits 1 and 2 are marked for identification as prefiled and received into evidence.)

(The prefiled direct testimony and summary of RYAN WATTS is copied into the record as if given orally from the witness stand.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plan and Carbon Plan	)	**DIRECT TESTIMONY OF RYAN WATTS ON BEHALF OF CLEAN POWER SUPPLIERS ASSOCIATION**

Q. MR WATTS, PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH CYPRESS CREEK RENEWABLES.

A. My name is Ryan Watts, and my business address is 3402 Pico Blvd, Santa Monica, California, 90405. I am a Grid Integration Engineer at Cypress Creek Renewables.

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

A. I have a Bachelors of Science in Electrical Engineering from the University of Nevada – Reno, and am a licensed Professional Electrical Engineer in the state of Nevada.

Q. PLEASE DESCRIBE YOUR BACKGROUND IN TRANSMISSION PLANNING.

A. I worked in the utility industry from 2015 to 2021 as a Transmission Planning Engineer, and then Manager of Transmission Planning, at NV Energy. At NV Energy my responsibilities included conducting FERC interconnection studies, overseeing NERC compliance, and ensuring compliance with FERC policy. In

2021, I joined Cypress Creek Renewables as a Grid Integration Engineer where I use Transmission Planning experience to support solar project development.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. I use Transmission Planning experience and power flow analysis to identify opportunities for interconnection of new solar resources, interface with utilities and ISOs to support all stages of the interconnection process, and support policy efforts with a technical focus.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION OR OTHER UTILITIES COMMISSIONS?

A. I have not testified before the North Carolina Utilities Commission or other utilities commissions.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purposes of my testimony are to provide a technical and engineering assessment of Duke's claimed Solar Interconnection Constraint, and to highlight additional measures that Duke could take to accelerate the pace of solar (and other) interconnections over the coming years.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR TESTIMONY.

A. First, I provide an overview of Duke's Solar Interconnection Constraint. I then discuss each of Duke's proffered justifications for the constraint, and explain why they fail to justify Duke's conservative approach to solar interconnection in its Carbon Plan modeling. I then explain why I believe that the interconnection rates reflected in CPSA's alternative portfolios are achievable. Finally, I discuss steps that Duke could take to achieve higher interconnection rates in the future.

Q. WHAT IS THE SOLAR INTERCONNECTION CONSTRAINT?

A. The Solar Interconnection Constraint is an upper bound of new solar (including solar plus storage) generating capacity Duke allowed its EnCompass model to select in each year of the planning period. Different limits were modeled in different portfolios. According to Duke, this modeling constraint represents "the most reasonable forecast of the Companies' ability to interconnect solar in the future."[1]

Although Duke's various Carbon Plan portfolios make different assumptions about solar interconnection in the medium to long term, all of its portfolios make very conservative assumptions about how much solar it can interconnect in the first three years of resource additions (2026-2028). Duke assumes that it can interconnect only 750 MW of solar in 2026, 1,050 MW in 2027, and 1,350 MW in 2028.

It's worth noting that Duke interconnected approximately 750 MW of new solar, comprising hundreds of distribution-scale projects, to its system in 2015 and 2017.[2] So Duke's Solar Interconnection Constraint assumes that the Company will achieve no improvement in its solar interconnection rates between 2016 and 2026.[3]

Q. WHAT IS THE SIGNIFICANCE OF THE SOLAR INTERCONNECTION CONSTRAINT IN THE CONTEXT OF THE CARBON PLAN?

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[1] Modeling Panel 162:14-18.

[3] Carbon Plan Appx. I p. 5; see also Duke Energy – Carolinas Carbon Plan Stakeholder Meeting 1 (Jan. 25, 2022, 2022), slide 60, available at https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=ffaa74fc-bcdf-4cb1-a298-8b6c473c86e4..

A. Solar represents the lowest cost carbon-free generating resource available to Duke in the near term, and in the absence of the constraint EnCompass would likely select significantly more solar additions in the near term. Limiting the amount of solar that can be selected results in EnCompass selecting other, higher-priced resources to meet the same resource needs, resulting in higher costs for ratepayers. This is discussed further in the direct testimony of CPSA witnesses Tyler Norris and Michael Hagerty.

Duke also proposes that the target volume for its 2022 solar procurement be equal to the Solar Interconnection Constraints for 2026 – even though the Company acknowledges that not all solar procured in the 2022 solar procurement is likely to be interconnected in 2026. Duke proposes to take the same approach for the 2023 and 2024 procurements, setting target volumes equal to the solar interconnection constraints in 2027 and 2028, respectively.[4] In his direct testimony, Mr. Norris discusses why this approach increases both risks and costs for Duke's ratepayers.

I. Evaluation of Solar Interconnection Constraint

Q. WHAT JUSTIFICATIONS HAS DUKE PROVIDED FOR THE SOLAR INTERCONNECTION CONSTRAINT?

In the stakeholder process, in response to discovery requests, and in its testimony, Duke has provided shifting justifications for its Solar Interconnection Constraint. These include:

1. Increasingly complex interconnections as solar facilities are located farther from existing infrastructure;

[4] Carbon Plan Ch. 4, p. 16.

2. Unknown future solar project size and impacts on interconnection;
3. Need for significant transmission upgrades;
4. Outage coordination;
5. Finite interconnection resources; and
6. Historic interconnection rates.

Given the importance of the Carbon Plan and its impacts on all of Duke's customers and North Carolinians as a whole, it is critical that Duke's assumptions are just, reasonable, and defensible. Until Duke can justify their study assumptions, provide demonstrable evidence of their claimed limitations to integration of solar resources, and develop a Carbon Plan with reproduceable results, the Carbon Plan's results will remain questionable. However, Duke has acknowledged that it "do[es] not have specific underlying calculations for the annual selection constraints," but is simply replying on its subjective "engineering judgment."[5]

Based on my experience in transmission planning and generation resource integration, I do not find Duke's justifications plausible or persuasive. The bases for my conclusions are discussed in more detail below.

Q. ONE FACTOR DUKE CITES IN FAVOR OF THE SOLAR INTERCONNECTION CONSTRAINT IS "INCREASINGLY COMPLEX INTERCONNECTIONS AS SOLAR FACILITIES ARE LOCATED FARTHER FROM EXISTING INFRASTRUCTURE."[6] WHAT IS YOUR ASSESSMENT OF THIS CLAIM?

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[5] Exhibit 1, Response to NCSEA-SACE DR 3-30.
[6] Modeling Panel at 156.

A. Duke has utterly failed to substantiate this claim. The only support for the claim that "Increasingly complex interconnections are one of the factors leading to longer durations" is a chart showing that the average time from execution of an Interconnection Agreement ("IA") to each project's in-service date has increased significantly from 2016 to 2021.[7]

Simply noting that construction lead times have increased in the past says nothing about whether they can be improved in the future. Long lead times between IA execution and completion of interconnection work can arise from a wide variety of factors in addition to "complex interconnections." These might include limited availability of engineering or construction resources, procurement delays, delays due to construction of contingent upgrades, and many other factors which can also be addressed through process improvement.

Q. DUKE SAYS THAT "IT IS LIKELY THAT LARGER SOLAR PROJECTS WILL REQUEST INTERCONNECTION GOING FORWARD, COMPARED WITH [SIC] HISTORIC SIZE OF PROJECTS."[8] AND IN DISCOVERY RESPONSES, DUKE CITES "UNKNOWN FUTURE SOLAR PROJECT SIZE AND IMPACTS ON INTERCONNECTIONS."[9] HOW DOES PROJECT SIZE IMPACT INTERCONNECTION RATES?

A. Project size suggests that Duke will be able to achieve significantly higher interconnection rates in the future. As stated in the Carbon Plan and Duke's testimony, Duke has interconnected hundreds of distribution-scale solar projects

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[7] Modeling Panel at 156-157.
[8] Modeling Panel p. 161.
[9] Modeling Panel Ex. 5.

over the last several years. The vast majority of those projects were 5 MW in capacity or smaller. Duke acknowledges that "larger projects should enable more aggregate MWs to be connected on an annual basis,"[10] but it is not known at this time what the size of projects will be in the future and whether larger projects will lead to additional transmission expansion projects beyond those contemplated in Appendix P."

Although Duke's modeling panel describes future project size as "unknown," the Carbon Plan itself states that "third-party owned projects are expected to be 50-80 MW and [that] utility-owned projects could be substantially larger."[11] Based on the testimony of Duke's transmission panel, the average size of the solar projects seeking interconnection in the first Definitive Interconnection System Impact Study (DISIS) cluster was approximately 83 MW.[12]

All things being equal, larger projects that enjoy economies of scale are likely to be more competitive in procurements, especially with respect to utility-ownership projects that are not limited to 80 MW. Furthermore, project size is not entirely out of Duke's control: in the 2022 procurement, the company specified that it was seeking only project 20 MW or larger. As Duke acknowledges, these larger project sizes are likely to lead to higher rates of interconnection in terms of megawatts interconnected.[13]

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[10] Modeling Panel Ex. 5.

[11] Carbon Plan: Appx I p. 6-7.

[12] Transmission Panel at 13:12-15.

[13] Duke also claims that larger project sizes may lead to

Duke claims that larger projects "are also more likely to trigger transmission system upgrades which could lead to longer lead times for individual projects."[14] While an individual project may require a localized transmission system upgrade due to a larger size, this is not necessarily true when considering regional power flow constraints such as the Duke Red Zone. In general, transmission system upgrades are triggered due to overloads of equipment from the aggregate flow of energy across various transmission elements within an interconnection study. Due to the networked nature of transmission systems, some upgrades are required due to aggregate amount of generation within an area of the transmission system, independent of the specific quantity of projects.

Transmission Planning is inherently built on planning for the unknown. – Developing agile responses to an ever-changing set of needs from the transmission system and adapting the interconnection process to improve legacy planning policies that may no longer add value is essential. Such uncertainty is an inherent feature of the process and does not provide a basis for slowing down interconnections.

Q. SEVERAL OF THE FACTORS CITED BY DUKE BOIL DOWN TO TRANSMISSION CONGESTION AND THE NEED FOR CONSTRUCTION OF SIGNIFICANT TRANSMISSION UPGRADES. HOW DO YOU RESPOND?

A. In testimony and in responses to data requests, Duke cites the need to construct significant transmission upgrades as a factor driving the Solar Interconnection

[14] Modeling Panel p. 161.

Constraint.[15] Significant improvements to the transmission grid will undoubtedly be required to meet the goals of HB 951. Although these improvements take time to construct, there is no reason to assume that Duke can only achieve very low levels of solar interconnection during its near-term execution plan.

In fact, Duke's own testimony about its planned transmission upgrades shows that solar interconnection rates should increase significantly by 2026, the first year of the planning period. According to Duke, the Red Zone Transmission Expansion Plan ("RZEP") projects *alone* will provide enough capacity on its transmission system to accommodate approximately 3.6 GW of solar capacity by the end of 2026 (and probably much more than that). The transmission study supporting the RZEP projects would enable the interconnection of at least 981 MW of solar projects in DEC and 2778 MW of projects in DEP.[16] Assuming the projects are prudently designed, they will also provide enough "headroom" to facilitate the interconnection of significantly more generation than that in the "Red Zones." In proposing the RZEP projects to the NCTPC, Duke stated that the planned completion date for every one of the RZEP projects was either September 2026 or December 2026.[17] There may also be additional developable solar capacity outside the Red Zone, in areas that do not require significant transmission upgrades.

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[15] Carbon Plan Appx. I p 7 ("Need for Transmission Upgrades"); Modeling Panel at 157 ("Areas that are most viable for solar development from a land availability / land quality standpoint are primarily located in transmission constrained regions"); Modeling Panel at 158 ("“transmission expansion needs and the time to construct new transmission infrastructure to accommodate increasing levels of renewables and other resources").

[16] Transmission Panel at 29-30.

[17] NCTPC 2021 Collaborative Transmission Plan Update (June 2022), at http://www.nctpc.org/nctpc/document/TAG/2022-06-27/M_Mat/2021_Collaborative_Transmission_Plan_MidYear%20Update-DRAFT%20-6-21-2022.pdf.

Although additional transmission upgrades will likely be required to achieve compliance with the 70% mandate of H.B. 951, the need for these upgrades does not support Duke's near-term Solar Constraint.

Q. DUKE HAS ALSO CITED THE NEED TO COORDINATE OUTAGES AS A LIMITING FACTOR FOR SOLAR INTERCONNECTION. HOW DO YOU RESPOND?

A. It is highly uncertain what impact this factor may have on solar interconnection rates. During the Carbon Plan stakeholder process and in discovery responses,[18] Duke has also cited outage coordination as a limit to integration of solar resources. However, new infrastructure requirements vary by project and are not determined until completion of DISIS.

Outage durations can be reduced for projects interconnecting to transmissions lines by reducing the time to construct new infrastructure at point of interconnection ("POI") substations. This can be done by allowing self-build by customers and utilizing temporary transmission lines ("shooflies").

Self-build was recently codified into the FERC interconnection process and could be implemented into Duke's interconnection process as well. By allowing the developer to self-build a POI substation meeting Duke's design requirements outside of the existing transmission corridor, the outage required to energize the substation can be reduced to the time it takes to interconnect the POI substation to the adjacent transmission line which is typically 5 days or less. With proper

[18] Exhibit 2, Duke Response to CPSA DR 3-15.

coordination and utilization of shooflies, this outage can be reduced to as little as 24 hours.

Duke has the ability to proactively steer third party development efforts into key areas to minimize outage durations, outage coordination, and optimize transmission investment. For capacity upgrades to provide deliverability of new resources, proactive greenfield transmission projects can reduce the outage impacts on existing facilities by building new transmission infrastructure that are not dependent upon outages and rebuilds of existing facilities. Proactive greenfield transmission investment can also be "right sized" to maximize the incremental capacity as a function of cost rather than reactively proposing ad hoc line rebuilds through the traditional generator interconnection process.

Duke's RZEP initiative is a good start and reflective of the type of proactive Transmission Planning analysis that can be performed both to accommodate renewables as well as provide siting signals to developers to target areas of the transmission system that are designed for streamlined solar integration.

Q. DUKE ALSO CITES "FINITE INTERCONNECTION RESOURCES WITH SOME ALLOCATED TO NON-SOLAR RESOURCES."[19] IS THIS A REASONABLE JUSTIFICATION FOR DUKE'S SOLAR INTERCONNECTION CONSTRAINT?

A. Duke is correct in claiming that interconnection resources are finite, which only stresses the importance of utilizing them as efficiently as possible. Brattle's economic analysis performed with standardized and conservative study

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[19] Modeling Panel at 160.

assumptions demonstrated that the least cost solution to meeting the Carbon Plan goals includes more than 1800 MW/year of solar, while the CPSA has compromised with a proposal of 1500 MW/year in 2026 and 2027, and 1800 MW/year in later years to recognize resource constraints.

1800 MW of solar per year is achievable while also reducing the total cost of the Carbon Plan. This can be accomplished by using shooflies to reduce the outage requirements at the POI when energizing POI substations, implementing more realistic study assumptions to reduce the burden of upgrades and outages for interconnection projects, and proactive greenfield transmission projects to pre-emptively build capacity to unbottle key areas for development.

Q. ANOTHER FACTOR CITED BY DUKE IS "THE COMPANIES' HISTORIC NUMBER OF ANNUAL INTERCONNECTIONS."[20] IS THIS A REASONABLE BASIS ON WHICH TO ESTABLISH A FUTURE INTERCONNECTION CONSTRAINT?

A. No. To say that prior interconnection results are the limit of future efforts ignores the fact that these capacity figures were accomplished by a dramatically larger number of interconnections. Ignoring this point would be to claim that improvements are unattainable. I agree with this Public Staff's view that it is not appropriate to use historical interconnections as a gauge or limit on future interconnections.[21] As the Public Staff notes (and as discussed in CPSA's comments),[22] there are a number of recent and expected changes that should lead

[20] Modeling Panel at 161.
[21] Public Staff Comments at 146.
[22] CPSA Comments at 15-17.

to higher interconnection rates. These include a significant increase in project size and shift from distribution to transmission interconnection; the implementation of queue reform; and a shift from piecemeal, reactive planning of transmission upgrades to a more proactive approach, as indicated by Duke's proposal of the RZEP projects.

Given the importance of the Carbon Plan on the future of decarbonizing the Carolinas, all reasonable efforts should be made to search for ways to improve by learning from the experiences of past rather than pointing to them as justification for why things cannot improve moving forward.

II. Achievability of Higher Solar Interconnection Rates

Q. IN ITS ALTERNATIVE PORTFOLIOS, CPSA HAS PROPOSED AN ALTERNATIVE INTERCONNECTION CONSTRAINT OF 1500 MW IN 2026 AND 2027, AND 1800 MW IN 2028 AND LATER YEARS. HOW DIFFERENT IS THIS FROM DUKE'S SOLAR INTERCONNECTION CONSTRAINT?

A. It is not that different. Duke's P1 portfolio calls for the addition of 1800 MW of solar a year starting in 2028 – the same rate of interconnection as CPSA's preferred portfolios and the sensitivity CPSA requested that Duke include in its supplemental modeling. Duke's Solar Interconnection Constraints in 2026 and 2027 are substantially lower: 750 MW and 1050 MW, respectively. CPSA's portfolios call for the addition of 1500 MW of solar resources in 2026 and 2027.

Thus. the total difference in assumed solar interconnections over the entire planning period is only 1200 MW – not a huge difference over a 25-year planning period.

However, during the period of the near-term execution plan the differences are significant.

Q. DO YOU BELIEVE THAT CPSA'S PROPOSED INTERCONNECTION RATES ARE ACHIEVABLE?

A. I do. I have already discussed several factors – larger average project sizes, the implementation of queue reform, and planned transmission upgrades – that should substantially increase Duke's rate of solar interconnections over its historic rates. H.B. 951 requires that 45% of solar additions come from third-party PPAs with projects limited to 80 MW, with the remaining 55% composed of utility-owned projects (with no size limit). Assuming an average PPA project size of 75-80 MW and an average Duke-owned project size of 100 MW (likely a conservative estimate), 1800 MW of solar a year would equate to approximately 10-11 PPA projects and approximately 10 Duke-owned projects a year.

By utilizing shooflies to reduce the outage requirements at the POI when energizing POI substations, implementing more realistic study assumptions to reduce the burden of upgrades and outages for interconnection projects, allowing for self-build by developers, and proactive greenfield transmission projects to pre-emptively build capacity to unbottle key areas for development, 1800 MW of solar per year should be comfortably achievable while also reducing total cost to ratepayers.

Peer states are already achieving interconnection rates substantially in excess of Duke's proposed caps.[23] In 2020, despite extensive disruptions related to the COVID-19 pandemic, several states were able to interconnect and install utility-

[23] CPSA Comments at 17-19.

scale solar volumes beyond Duke's proposed caps, including Texas at approximately 2480 MW, California at 1650 MW, and Florida at 1640 MW. In that same year, Virginia interconnected 675 MW, and Georgia installed 637 MW.

In 2021, utility-scale solar installations totaled approximately 3900 MW in Texas, 1330 MW in California, 1100 MW in Florida, 900 MW in Virginia, and 760 MW in Georgia. Nevada, a state with only 34% of North Carolina's net summer generation capacity and 26% of North Carolina's annual electricity sales, interconnected 611 MW of utility-scale solar.[24]

Q. DOES CPSA BELIEVE THAT EVEN HIGHER INTERCONNECTION RATES ARE POSSIBLE OVER TIME?

A. Absolutely. Over the long term there is no reason to believe that significantly higher rates cannot be achieved. CPSA proposed a 1500 MW interconnection constraint in 2026 and 2027 not because that represents the upper limit of interconnection capability, but because (based on CPSA's modeling) the addition of 1500 MW of solar in those years, and 1800 MW in 2028 and 2029, would be sufficient to achieve compliance with the 70% carbon reduction mandate by 2030.

III. Additional Steps to Speed Up Solar Interconnections

Q. IN ITS TESTIMONY DUKE CITES "PROCESS IMPROVEMENTS" IT IS UNDERTAKING TO IMPROVE INTERCONNECTION RATES.[25] HAS DUKE REACHED OUT TO INTERCONNECTION CUSTOMERS OR

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[24] See CPSA comments at 17; EIA Electric Power Monthly, Table 6.2B, available at https://www.eia.gov/electricity/monthly/ (retrieved February 2022).

[25] Transmission Panel at 43.

OTHER STAKEHOLDERS REGARDING THIS PROCESS IMPROVEMENT INITIATIVE?

A. Not to my knowledge.

Q. **ARE THERE ADDITIONAL STEPS DUKE CAN TAKE TO ACCELERATE THE PACE OF SOLAR INTERCONNECTION?**

A. Yes, there are several things. Both Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC) use interconnection study criteria that go beyond the required North American Electric Reliability Council (NERC) TPL-001-4 study criteria requirements. This results in simulating system conditions that are unnecessary to maintain compliance. This is illogical and inconsistent with the intentions of the NERC TPL-001-4 standard. Duke should consider whether its interconnection study criteria are appropriate or whether they are unreasonably conservative and would result in the construction of unnecessary upgrades. Revising these study assumptions to accurately reflect the TPL-001-4 requirements may reduce the need for new infrastructure, resulting in shorter interconnection times and lower costs to ratepayers, while also maintaining NERC compliance.

Q. **WHAT DO YOU MEAN WHEN YOU SAY THAT DUKE'S STUDY CRITERIA GO BEYOND THE REQUIREMENTS OF NERC STANDARDS?**

A. The NERC TPL-001-4 standard includes various contingency types to represent different system outage conditions, ranging from P0 to P7. The P3 contingency is simulation of a loss of a generator unit, followed by System Adjustments that may include "Transmission changes and re-dispatch of generation", followed by loss of another transmission element. The P3 contingency type is being applied by both DEC and DEP in a way that creates unnecessary system stress by not utilizing the flexibility within the TPL-001-4 standard to mitigate issues through System Adjustments[26].

The intent of this contingency type is to simulate the behavior of the transmission system after loss of a generator unit, followed by system operator adjustments which can include re-dispatch of area generators to reduce system stress or reconfiguration of the transmission system in preparation for the next contingency that may occur, and then simulating that successive contingency. This System Adjustment period allows great flexibility by system operators to maximize the reliability of the transmission system after loss of the initial generator unit to prevent future reliability issues, but neither DEC nor DEP reflect this flexibility in their study procedures. Both DEC and DEP assume a uniform redispatch of system generation after loss of the first generator unit using different criteria, but neither attempt to maximize reliability as allowed within the standard.

It's important to note the System Adjustments period is intended to represent a short-term operating condition until the initial generator unit can be restored while reliability is the primary focus, not a long-term operating condition where economics are the focus.

However, DEC's study process for P3 contingencies focuses on economics, rather than reliability. It assumes loss of the first generator unit followed by an economical redispatch of remaining area generators to replace the lost generation during the

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[26] NERC TPL-001-4, Table 1

System Adjustment period. This economical redispatch does not consider impacts to reliability but demonstrates that DEC is willing to redispatch generation within the System Adjustment period, just not in a way to maximize reliability. Whether intentional or not, this study process creates unnecessary system stress and does not maximize the capability of the existing transmission system, potentially leading to identification of unnecessary new infrastructure being identified for generator interconnections that could be avoided with a targeted redispatch with a focus on reliability. By applying the TPL-001-4 standard, DEC can revise their study assumptions to take advantage of the System Adjustment period by simulating a redispatch of the system with a goal of reliability, rather than economics, which can reduce the new infrastructure requirements.

Likewise, DEP's study process for P3 contingencies favors a uniform redispatch rather than reliability. It assumes loss of the first generator unit followed by a universal scaling of all area generators to replace the lost generation during the System Adjustment period. Like DEC, this universal scaling of generation does not consider impacts to reliability. This demonstrates that DEP is willing to redispatch generation within the System Adjustment period, just not in a way to maximize reliability. Whether intentional or not, this study process creates unnecessary system stress and does not maximize the capability of the existing transmission system, potentially leading to identification of unnecessary new infrastructure being identified for generator interconnections that could be avoided with a targeted redispatch with a focus on reliability. By applying the TPL-001-4 standard, DEP can revise their study assumptions to take advantage of the System Adjustment period by simulating a redispatch of the system with a goal of reliability, rather than a uniform redispatch, which can reduce the new infrastructure requirements.

DEP also simulates Transmission Reserve Margin (TRM) scenarios for P3 contingencies. Their methodology is to import 1826 MW from neighbors, turn off each nuclear unit one at a time, and scale down the remaining area generation. P1 contingencies are then ran on each of these scenarios to complete the P3 analysis. In simpler terms, DEP is simulating loss of a nuclear generator unit, followed by importing of 1826 MW of TRM from neighbors and turning down area generation to balance the system to represent their System Adjustment period, and then finishing the P3 analysis. This methodology does not maximize reliability within the System Adjustment period and is flawed in that it assumes 1826 MW of TRM imports regardless of the size of the generator unit initially lost, even if this requires reducing dispatch of other area generators to balance the TRM imports. This does not maximize reliability and can even worsen reliability by responding to loss of a nuclear generator unit with a voluntary reduction of other generator units to justify the 1826 MW of TRM imports. Only the amount of TRM required to offset loss of the initial nuclear generator unit should be imported to accurately reflect the purpose of TRM, and any redispatch within DEP can be done with a focus on maximizing reliability instead.

Revising DEC and DEP's study assumptions to reflect the intention of the TPL-001-4 P3 contingency type by utilizing the System Adjustment to maximize reliability may reduce the scope of upgrades required for new interconnection projects, reducing both costs and the challenges of constructing new infrastructure that are cited as justification for limiting solar resource integration.

Q. WHAT ELSE CAN BE DONE TO IMPROVE INTERCONNECTION RATES?

A. In his direct testimony, CPSA Witness Tyler Norris discusses CPSA's recommendation that the Commission establish an independent technical review process, akin to the independent technical review committee directed by the Commission to review Duke's proposed Solar Integration Services Charge (SISC), to analyze Duke's solar interconnection constraints and consider solutions for improving interconnection rates. I also have other, more specific recommendations.

Allowing interconnection customers to construct (in whole or in part) their own upgrades would also reduce strain on Duke's "finite interconnection resources," and allow for higher interconnection rates without endangering reliability. Self-build by developers has recently been codified by FERC in Order 845 and allows for developers to self-build standalone network upgrades such as POI substations. Incorporating a similar self-build opportunity for developers interconnecting to Duke would reduce strain on Duke's finite interconnection resources, freeing up resources to focus on capacity related upgrades to accelerate the rate of generator interconnections.

By maximizing self-build opportunities for POI substations along with shooflies to reduce the outage required to energize them, the strain on Duke's interconnection resources would be reduced both from a construction capacity as well as outage coordination point of view, improving reliability during construction while also facilitating increased rates of generator interconnections.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Ryan Watts Testimony Summary

My name is Ryan Watts and I am a Grid Integration Engineer at Cypress Creek Renewables. Before coming to Cypress Creek I was the Manager of Transmission Planning at NV Energy, a public utility that generates, transmits and distributes electric service to more than 1.3 million customers in northern and southern Nevada.

In my testimony I provide a technical and engineering assessment of Duke's claimed Solar Interconnection Constraint, and highlight additional measures that Duke could take to accelerate the pace of solar and other interconnections over the coming years. I believe that the interconnection rates reflected in CPSA's alternative portfolios are achievable. In my testimony, I highlight steps Duke could take to achieve them.

The Solar Interconnection Constraint is a limit on new solar (including solar plus storage) generating capacity that Duke allows its EnCompass model to select in each year of the planning period. As a result of this constraints, all of Duke's portfolios make conservative assumptions regarding how much solar the company can interconnect in the first three years of resource additions (2026-2028). This is most evident in the fact that Duke assumes that it will achieve no improvement in its solar interconnection rates between 2016 and 2026 despite Duke's Red Zone Transmission Expansion Plan ("RZEP") upgrades *alone* providing enough capacity to accommodate approximately 5.4 GW of solar capacity by mid-2027[1].

As discussed in the testimony of CPSA witnesses Tyler Norris and Michael Hagerty, solar represents the lowest cost carbon-free generating resource available to Duke in the near term, and in the absence of the constraint, EnCompass would likely select

[1] Transmission Panel at 29-30.

significantly more solar additions in the near term. Limiting the amount of solar that can be selected based on presumed interconnection constraints results in other, higher-priced resources being selected to meet the same resource needs, resulting in higher costs for ratepayers.

Given the significant impact of this constraint on the Carbon Plan and on Duke's customers, the Commission should closely examine Duke's assumptions about interconnection. Duke has acknowledged that it "do[es] not have specific underlying calculations for the annual selection constraints," but is simply making a forecast based on its subjective "engineering judgment."[2] Duke has provided shifting justifications for its Solar Interconnection Constraint in the stakeholder process, discovery responses, and testimony. These have included:

1. Increasingly complex interconnections as solar facilities are located farther from existing infrastructure;
2. Unknown future solar project size and impacts on interconnection;
3. Outage coordination;
4. Need for significant transmission upgrades;
5. Finite interconnection resources; and
6. Historic interconnection rates.

Based on my experience in transmission planning and generation resource integration, I do not find Duke's justifications plausible or persuasive.

Duke cites "Increasingly complex interconnections as solar facilities are located farther from existing infrastructure" as a justification for the constraint, but has failed to

[2] Exhibit 1, Response to NCSEA-SACE DR 3-30.

substantiate this claim, citing a chart showing the average time from execution of an Interconnection Agreement ("IA") to each project's in-service date has increased significantly from 2016 to 2021.[3] These increased lead times can arise from a variety of factors in addition to "complex interconnections," some of which can be addressed through process improvement.

Duke also acknowledges that larger projects should enable more aggregate MWs to be connected on an annual basis, but simultaneously claims that larger projects may require larger upgrades to the transmission system.[4] Uncertainty regarding future project sizing is inherent to Transmission Planning and adapting the interconnection process to improve legacy planning policies that no longer add value is essential.

Significant improvements to the transmission system will undoubtedly be required to meet the goals of HB 951, but there is no reason to assume that Duke can only achieve low levels of solar interconnection. Historic interconnection rates are not predictive of future interconnection rates, a viewpoint expressed by Public Staff as well.[5] Duke's own RZEP demonstrates the value of proactive transmission planning, facilitating at least 3.6 GW of new solar capacity in the Red Zone and an additional 1.8 GW elsewhere. All of these upgrades are expected to be completed by mid-2027.

Outage coordination is a relevant factor in scheduling the construction of upgrades. However, the specifics of these outages cannot be determined until completion of DISIS. Duke also fails to acknowledge that temporary transmission lines ("shooflies") can be utilized to reduce outage durations. The use of shooflies, coupled with customer self-build

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[3] Modeling Panel at 156-157.
[4] Modeling Panel Ex. 5.
[5] Public Staff Comments at 146.

of standalone system upgrades, could significantly reduce the burden on Duke's "finite interconnection resources."

And all reasonable efforts should be made to search for ways to improve the rate of solar interconnection to reduce costs for ratepayers. As described in my testimony, Duke's current interconnection study processes are unnecessarily conservative, opting to model select contingencies in a way that does not maximize reliability for temporary operating conditions, increasing the probability of requiring transmission upgrades that are costs borne by the ratepayer. Duke is not obligated to make such conservative assumptions; they choose to.

CPSA's proposed alternative interconnection constraint is reasonable and achievable, and only represents a total difference in assumed solar interconnections of 1200 MW over a 25-year planning period. CPSA's proposed constraint does not necessarily represent the true limit of interconnection capability. But unlike Duke's proposed constraint, the pace of interconnection proposed by CPSA would be sufficient to meet the 70% carbon reduction mandate of HB 951 by 2030.

Higher interconnection rates are possible through process improvement with proactive transmission planning, revising study assumptions to be more realistic while maintaining compliance and reliability, maximizing self-build opportunities to reduce strain on Duke's finite interconnection resources, and utilizing shooflies to reduce the impact of outage coordination while improving reliability during construction. These efforts are complimentary and will facilitate increased rates of generator interconnections.

MR. SNOWDEN: Thank you, Chair Mitchell.

CHAIR MITCHELL: Before we adjourn, Mr. Dodge.

MR. DODGE: Thank you, Chair Mitchell. Good evening, just about, I think. I can't believe we're here almost at 5 o'clock. I'm Tim Dodge with North Carolina Electric Membership Corporation. On September 2nd, NCEMC caused to be filed two sets of testimony in this docket the testimony of Amadou Fall and Lee Ragsdale. And with regard to Mr. Fall, NCEMC has conferred with all parties and have confirmed their willingness to waive the cross of Mr. Fall. And it's my understanding the Commission does not have questions for Mr. Fall at this time. So therefore, we would request that his prefiled testimony consisting of 13 pages with a correction filed on September 9th be copied in the record as if given orally from the stand, and that Mr. Fall be excused from appearing.

CHAIR MITCHELL: Hearing no objection, your motion is allowed. Your witness is excused.

(WHEREUPON, the prefiled direct testimony and summary of AMADOU FALL, as corrected, is copied into the record as if given orally from the witness stand.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
	)	**TESTIMONY OF AMADOU**
Duke Energy Progress, LLC, and	)	**FALL ON BEHALF OF NORTH**
Duke Energy Carolinas, LLC,	)	**CAROLINA ELECTRIC**
2022 Biennial Integrated Resource	)	**MEMBERSHIP CORPORATION**
Plan And Carbon Plan	)	

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Amadou Fall. My business address is 3400 Sumner Boulevard, Raleigh, North Carolina, 27616.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. Currently I am employed as the Senior Vice President, Power Supply Division and Chief Operating Officer of North Carolina Electric Membership Corporation, which I will refer to as “NCEMC.” As the Chief Operating Officer at NCEMC responsible for managing its Power Supply Division, my responsibilities include supervision and oversight of the company transmission and power supply resource acquisition. I also am responsible for managing system operations, planning and dispatch, including installed generation and purchase power contracts, engineering services, grid operations and planning, and edge of grid / distributed energy resources integration. I also provide leadership and guidance for the Division, and assistance to the Executive Vice President and CEO concerning corporate strategy planning, and management effectiveness.

Q. WOULD YOU PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND, AND IDENTIFY ANY OTHER ACTIVITIES WHICH YOU BELIEVE INFORM YOUR TESTIMONY IN THIS PROCEEDING?

A. I hold a Bachelor of Sciences degree in Electrical and Electronics Engineering from the New York Institute of Technology and a Master of Science in Engineering from Drexel University. I have been in the electric utility and energy industry throughout my career in various areas of utility operations and management, risk management, energy trading, regulatory affairs, transmission services, power scheduling, and marketing operations. Prior to joining NCEMC in 2021, I was Chief Executive Officer at the National Renewables Cooperative Organization (NRCO) from 2008 to 2021. I was also previously employed at ACES Power Marketing, Exelon, Williams, and PPL Corporation.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY IN THIS DOCKET.

A. Consistent with the Commission's July 29, 2022, *Order Scheduling Expert Witness Hearing, Requiring Filing of Testimony, and Establishing Discovery Guidelines* in this docket, my testimony is intended to provide the Commission with input regarding the following topics as defined in the Issues Report filed by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, "Duke") on July 22, 2022:

- Whether Duke's recommended Carbon Plan compliance pathways were consistent with least cost planning principles and ensured reliability of the system;
- The reasonableness of the near-term actions and long-term pathways proposed by Duke for consideration by the Commission, as well as providing an appropriate framework for updates and revisions in future biennial reviews;
- The value that Duke's current carbon-free or low-carbon generation resources will play in meeting the interim and 2050 carbon reduction goals, and recognition of the value of resource diversity for reliability purposes; and
- General support for Duke's consideration of consolidated operations of DEC and DEP to provide both cost savings through operational efficiencies and reliability improvements for customers, and moving forward with additional steps to evaluate

the potential merger of the utilities, subject to further regulatory approvals and actions to address cost allocation and rate disparity concerns.

My testimony is also intended to support and supplement the testimony of Lee Ragsdale on behalf of NCEMC in this proceeding that further discusses issues related to the Red-Zone Transmission Expansion Plan ("RZEP") projects, transmission planning, and the recognition of distributed resources and grid edge resources to help ensure reliability is maintained while achieving the most cost-effective plan for compliance with the carbon reductions goals established in House Bill 951 ("H951"), now codified as N.C. Gen. Stat. § 62-110.9.

Q. FOR PURPOSES OF BACKGROUND, WHAT KIND OF ORGANIZATION IS NCEMC AND WHAT ARE THE RELATIONSHIPS OF ITS MEMBERS TO THE COMPANY?

A. NCEMC is a generation and transmission cooperative. It provides wholesale power and other services to 25 of the 26 electric cooperatives based in North Carolina that provide retail electric service to member-consumers in the State. These member cooperatives, commonly known as electric cooperatives but formally called electric membership corporations, were created during the 1930's and 1940's to bring electric power to areas that were deemed by others as too remote and uneconomical to serve. These distribution cooperatives are independent, not-for-profit membership corporations whose members are the retail consumers who buy power from them. These member-consumers own their local distribution cooperative and elect the Board of Directors that governs it.

NCEMC is also a not-for-profit membership corporation created under Chapter 117 of the North Carolina General Statutes. It has 25 members, all of which are North Carolina based distribution cooperatives providing retail electric service to more than 2.5 million homes, farms, and businesses throughout the State. In fact, our members provide electric service in 93 of the State's 100 counties through approximately 106,000 miles of distribution lines that extend across almost 45 percent of North Carolina's land mass.

Q. WOULD YOU BRIEFLY DESCRIBE THE PROCESS BY WHICH NCEMC ACQUIRES POWER SUPPLY RESOURCES?

A. The service territories of NCEMC's members are located within the control areas and interconnected to the transmission systems of the three major investor-owned utilities with operations in North Carolina, DEC, DEP, and Virginia Electric Power Company, d/b/a as Dominion Energy North Carolina ("Dominion"). NCEMC seeks to serve all of its members in the most cost-effective manner possible using a balanced portfolio of owned generation and purchase power contracts.

Q. ARE THERE ANY OTHER OPERATIONAL CHARACTERISTICS ABOUT NCEMC THAT IMPACT ITS PLANNING PROCESS OR POWER SUPPLY OPTIONS?

A. Yes. First, because of how NCEMC has evolved, the company is a transmission dependent utility that owns no transmission lines or related transmission assets, except for two short 230 kV lines that interconnect the Anson and Hamlet combustion turbine plants to the DEP 230 kV transmission system. Instead, the company purchases transmission services from DEP, DEC, and Dominion under their respective Open Access Transmission Tariffs, and regularly intervenes and participates in Duke's transmission rate cases before the Federal Energy Regulatory Commission (FERC). NCEMC purchases Network Service from DEC, DEP, and Dominion, the terms of which are memorialized in the Network Integration Transmission Service Agreements and the Network Operating Agreements for each company. NCEMC also purchases Firm Point-to-Point transmission service from other transmission providers, including PJM and Southern Company, to bring purchased power resources from these suppliers into NCEMC's three supply areas.

II. RELIABILITY AND LEAST COST

Q. PLEASE SHARE NCEMC'S PERSPECTIVE WITH REGARD TO THE GUIDANCE PROVIDED BY THE GENERAL ASSEMBLY IN ENACTMENT OF THE CARBON REDUCTION GOALS IN H951.

A. As discussed in our July 15, 2022, comments in this docket, NCEMC stresses the critical guardrails called for in N.C.G.S. § 62-110.9 to guide the Commission in its adoption of a Carbon Reduction Plan. Specifically, the Commission must continue to ensure that least cost planning and principles are followed, while at the same time ensuring that the Carbon Plan at a minimum maintains the reliability and adequacy of the existing grid. N.C.G.S § 62-110.9 further provides the Commission with oversight of the process and tools to monitor and update the Carbon Plan as appropriate on a periodic basis, including discretion with regard to the mix of generation and grid resources to be considered, as well as the timeline for compliance with the interim carbon reduction goals.

Q. DOES NCEMC BELIEVE THAT THE DUKE'S RECOMMENDED PLAN, WITH ITS MULTIPLE PATHWAYS TOWARDS COMPLIANCE, COMPORTS WITH THE GUIDANCE PROVIDED BY THE GENERAL ASSEMBLY?

A. Yes. Duke's May 16, 2022, recommended Carbon Plan filings and in its August 19, 2022, testimony presents the Commission with a short-term action plan to lay the foundation for compliance with the carbon reduction goals in a reasonable manner that is consistent with least-cost principles while maintaining system reliability, and also provides a flexible framework with multiple pathways to achieve the longer-term goals of achieving carbon neutrality in a least cost, reliable manner. This framework is dependent on many variables, including additional regulatory and policy decisions at the State and federal level, that will take shape in the coming years and be updated and incorporated into the Carbon Plan by the Commission in the biennial review process. As discussed by Duke Witness Bowman, the iterative, biennial Carbon Plan process called for in H951 is intended to evolve over time and incorporate new information, consumer preferences, changes in technologies and market dynamics, and evolution of state and federal policies. By taking short-term actions as appropriate, and continuing to update cost assumptions and monitor changing conditions over time, the Commission will be able to better "chart the least-cost path to compliance with the best available information available at the time without locking into a more expensive or risky resource mix."[1]

[1] Direct Testimony of Kendal C. Bowman for DEC and DEP, at pp. 28-30.

Q. HAS DUKE ADEQUATELY CONSIDERED THE VALUE OF RESOURCE DIVERSITY TO MAINTAINING SYSTEM RELIABILITY AS PART OF ITS RECOMMENDED PLAN?

A. Yes, I believe so. Duke's current generation portfolio includes a broad spectrum of reliable and increasingly clean resources, many of which will continue to play an important role towards carbon compliance for decades to come. However, as conventional generating resources such as coal decline in usage and intermittent resources such as wind and solar become a larger portion of its generation mix to comply with carbon reduction goals, additional measures to ensure reliability must be fully considered. As discussed in the testimony of Duke witnesses Holeman and Roberts, one of the critical initial steps in developing the Carbon Plan is to "maintain[] robust resource diversity to have as many tools available in DEC and DEP System Operators' toolbox to manage and respond to system dynamics and a variety of operating conditions."[2]

N.C.G.S. § 62-110.9(1) specifically called for consideration of a broad range of tools, including "power generation, transmission and distribution, grid modernization, storage, energy efficiency measures, demand-side management, and the latest technological breakthroughs to achieve the least cost path consistent with this section to achieve compliance with the authorized carbon reduction goals." Duke's recommended Carbon Plan included modeling of these measures and the supporting testimony incorporated extensive stakeholder input and comments on these resource options. In general, Duke's approach takes an "all-of-the-above" approach over the course of the Carbon Plan horizon

[2] Direct Testimony of Dewey S. Roberts and John Samuel Holeman III for DEC and DEP, at pp. 48-9.

Attachment 1

Corrected Page 9 of Direct Testimony of Amadou Fall (filed September 9, 2022)

and provides a reasonable basis and timeframe to integrate the resulting mix of diverse resources reliably and in a manner consistent with least cost principles. As noted in the Modeling and Near-Term Actions Panel testimony,[3] Duke's modeling of the supplemental portfolios proposed by the Public Staff continued to show the value of resource diversity by selecting a variety of resources, including new dispatchable generation resources, for both meeting the interim carbon reduction goals, as well as the 2050 carbon neutrality goals.

Q. DO YOU AGREE WITH DUKE'S CONCERNS THAT REDUCED RESOURCE DIVERSITY WILL IMPACT DUKE'S ABILITY TO RELY ON MARKET ASSISTANCE FOR RELIABILITY PURPOSES?

A. Yes, as discussed on Page 110 of the Modeling and Near-Term Actions Panel testimony, the ability for Duke to rely on market assistance from neighboring utilities for reliability planning purposes, particularly to meet its winter planning needs, is uncertain due to similar decarbonization efforts taking place across the Southeast and mid-Atlantic regions, and declines in historic diversification of generation resources. NCEMC agrees with Duke that continuing to evaluate changes in neighboring system resource portfolios and load profiles will be important considerations going forward to support those assumptions of regarding resource availability.

III. CONSOLIDATED OPERATIONS AND MERGER

[3] Direct Testimony of Glen Snider, Bobby McMurry, Michael Quinto, and Matt Kalemba for DEC and DEP (the "Modeling and Near-Term Actions Panel") at p. 74.

Q. DOES NCEMC SUPPORT THE OVERALL FRAMEWORK AND TIMELINE FOR CONSOLIDATED OPERATIONS AS MODELED AND PLANNED IN DUKE'S RECOMMENDED CARBON PLAN?

A. Generally, yes. As originally presented in Duke's recommended Carbon Plan and later supported by the direct testimony of Duke Witnesses Bateman and Peeler, on the whole the proposed consolidation of DEC and DEP system operations presents a broad range of customer benefits and will reduce the costs of compliance with the H951 carbon reduction goals for all consumers and provide additional reliability benefits. The consolidated operations will require regulatory approvals at the State and federal level, and extensive input from retail and wholesale customers. NCEMC supports an expeditious timeline for the proposed combination of the DEC and DEP balancing areas to provide the overall operational efficiencies and cost savings benefiting transmission customers.

Q. WITH REGARD TO THE LONGER-TERM GOAL OF A MERGER OF DEC AND DEP, WHAT ARE THE IMPLICATIONS OF THE MERGER FOR NCEMC'S MEMBERS?

A. NCEMC acknowledges that a merger of DEC and DEP presents even greater overall potential benefits to Duke's retail and wholesale customers, but the rate implications will vary by utility and customer class. There will be rebalancing of costs necessary over time in order to transition to an equitable outcome for all customers, including among NCEMC's members, and it will take time to secure the additional regulatory approvals required. The potential merger timeline included as Exhibit 1 to the Bateman and Peeler testimony appears reasonable, and NCEMC is committed to working with Duke and other stakeholders to investigate the benefits of both the combined system operations and the potential merger of the utilities. NCEMC recommends that the Commission issue a procedural order in either a new generic docket or the original merger dockets[4] to establish stakeholder engagement and reporting timelines consistent with the schedule proposed by Duke.

IV. EQUITABLE ALLOCATION OF CARBON PLAN COSTS

Q. DESCRIBE HOW THE COSTS OF COMPLIANCE WITH THE CARBON REDUCTION GOALS IN H951 MAY HAVE DISPARATE RATE IMPACTS.

A. As stated in our July 15 comments, achieving the goals of the Carbon Plan will require investments by each of the Duke operating companies, the costs of which, absent some change, would be allocated to DEC's and DEP's retail and wholesale customers under currently applicable cost allocation guidance. However, the jurisdiction receiving the benefits of such investments will not in many cases coincide in a proportional manner with the costs that are incurred. For example, the proposed RZEP public policy transmission projects discussed extensively in Duke witness Farver and Roberts, and also discussed in the testimony of Lee Ragsdale, would be located across the DEP and DEC service areas, with the larger number of projects and costs being proposed in the DEP service area (14 projects totaling $321 million, as compared to four projects totaling $241 million). The additional solar generation projected to be interconnected as a result of the RZEP projects would provide Carbon Plan compliance benefits for the recommended Carbon Plan filed by Duke. Absent some change to the cost allocation method for the RZEP projects, the

[4] *In the Matter of Application of Duke Energy Corporation and Progress Energy, Inc. to Engage in a Business Combination Transaction and to Address Regulatory Conditions and Codes of Conduct*, Docket Nos. E-2, Sub 998 and E-7, Sub 986.

allocation of costs would be disproportionately borne between DEC and DEP. Adjustments to the governing cost allocation framework will be necessary at State (in general rate cases, interconnection procedures, and other proceedings) and at FERC (through changes to Duke's Joint OATT), as well as in other contractual or regulatory agreements to assign the costs, including affected systems costs, to each respective utility in a proportional manner to the benefits being received by the utility's customers resulting from the investments being made.

Q. WHAT IS YOUR PERSPECTIVE WITH REGARD TO THE ALTERNATIVE ARRANGEMENTS DESCRIBED BY WITNESS BATEMAN THAT DUKE HAS CONSIDERED TO MITIGATE OR OFFSET SOME OF THE DISPROPORTIONATE ALLOCATION OF COSTS THAT MAY RESULT FROM A LEAST-COST CARBON PLAN?

A. N.C.G.S. § 62-110.9 calls for the Commission to develop a plan to meet the carbon reduction goals across DEC and DEP's combined systems in a least cost manner, and does not assign or limit any of the resources or investments to a utility's service area. To the extent that the resources being identified are being selected consistent with least cost planning principles, it is appropriate to consider mitigation measures such as those presented by Ms. Bateman to address the cost allocation concerns where they arise. These alternative options represent the kind of thinking that will be necessary to achieve a least cost outcome, and may provide an interim measure to address the some of these rate allocation concerns that may result from H951 implementation while longer-term measures such as consolidated system operations and potential merger can be investigated and approved, if found to be feasible and in the public interest.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

North Carolina Electric Membership Corporation ("NCEMC")
Summary of Direct Testimony – Amadou Fall
NCUC Docket No. E-100, Sub 179

My name is Amadou Fall and I serve as Senior Vice President, Energy Delivery in the Power Supply Division and Chief Operating Officer at NCEMC. The purpose of my testimony is to provide the Commission with NCEMC's perspective regarding the recommended Carbon Plan filed by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, "Duke") on May 16, 2022, and the associated testimony and comments filed by Duke and intervenors since that time.

My testimony first indicates NCEMC's support for the approach taken in Duke's recommended Carbon Plan in laying out multiple pathways towards compliance in order to provide the Commission with a flexible framework to achieve the carbon reduction goals called for in House 951 in a least cost, reliable manner. This framework, along with the biennial "check and adjust" process will allow the Carbon Plan to evolve over time and incorporate new information, technologies, and changes in regulatory and market conditions.

My testimony further seeks to recognize and support the value of resource diversity in maintaining system reliability, including the value that the current carbon-free or low-carbon generation resources owned or operated by Duke will play in meeting the interim and 2050 carbon reduction goals, as well as the value of new and developing technologies that can contribute to a more diverse and robust portfolio of resources to ensure that the reliability of the system is maintained.

My testimony also indicates NCEMC's general support for the overall framework and timeline for consolidated operations of DEC and DEP proposed as part of Duke's recommended carbon plan, which has the potential to provide both cost savings through operational efficiencies and reliability improvements for Duke's retail and wholesale customers. In addition, these consolidated operations may help address some of the concerns over the disproportionate allocation of costs that may otherwise result from Carbon Plan compliance.

This concludes my summary.

MR. DODGE: And with regard to our second witness Mr. Ragsdale, I similarly note that intervenors have agreed to waive cross of Mr. Ragsdale but it's my understanding the Commission may have questions, so we anticipate having Mr. Ragsdale here to testify on Monday.

CHAIR MITCHELL: All right. And that's correct. Any additional matters for my consideration before we adjourn?

(No response)

CHAIR MITCHELL: Not hearing any, so we will be back on the record at 11 o'clock on Monday. We will begin the day with -- in accordance to what I think is the most recent witness list of Mr. Fitch. Is that correct?

MS. THOMPSON: Chair Mitchell, Mr. Fitch does have a conflict at the end of the day on Monday, which we could work around. So if it's the Commission's preference to just continue in the order, we can make that work.

CHAIR MITCHELL: Well, I'm just going off -- had the parties agreed on a different order? I'm going off the order that's in front of me.

MS. THOMPSON: We've been in such a fluid situation that we haven't yet had a chance to confer about taking Mr. Fitch in different order so we can just make him -- we'll get him here at 11:00 a.m. on Monday.

CHAIR MITCHELL: Okay.

MS. THOMPSON: Thank you.

CHAIR MITCHELL: All right. Anything else before we go off the record?

(No response)

CHAIR MITCHELL: With that, we'll be off the record. Thank you very much.

(The hearing was adjourned at 4:56 p.m. and set to reconvene at 9:00 a.m. on September 26, 2022 at 10:30 a.m.)

C E R T I F I C A T E

I, TONJA VINES, DO HEREBY CERTIFY that the proceedings in the above-captioned matter were taken before me, that I did report in stenographic shorthand the Proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability.

Tonja Vines