PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Tuesday, September 20, 2022

TIME: 9:34 a.m. - 12:46 p.m.

DOCKET NO.: E-100, Sub 179

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Daniel G. Clodfelter

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

Commissioner Karen M. Kemerait

IN THE MATTER OF:

Duke Energy Progress, LLC, and

Duke Energy Carolinas, LLC,

2022 Biennial Integrated Resource Plans

and Carbon Plan

VOLUME: 17

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

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

Jack E. Jirak, Esq., Deputy General Counsel
Kendrick C. Fentress, Esq., Associate General Counsel
Jason A. Higginbotham, Esq., Associate General Counsel
Kathleen Hunter-Richard, Esq.
Duke Energy Corporation
Post Office Box 1551
Raleigh, North Carolina 27602

Andrea Kells, Esq.
E. Brett Breitschwerdt, Esq., Partner
McGuireWoods LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601

Vishwa B. Link, Esq., Partner
McGuireWoods LLP
Gateway Plaza
800 East Canal Street
Richmond, Virginia 23219-3916

A P P E A R A N C E S Cont'd.:

Lara S. Nichols, Vice President,
State & Federal Regulatory Legal
Duke Energy Corporation
4720 Piedmont Row Drive
Charlotte, North Carolina 28210

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:
Taylor Jones, Esq., Regulatory Counsel
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

FOR SOUTHERN ALLIANCE FOR CLEAN ENERGY, NATURAL RESOURCES DEFENSE COUNCIL, and THE SIERRA CLUB:
Gudrun Thompson, Esq., Senior Attorney
David, L. Neal, Esq., Senior Attorney
Nicholas Jimenez, Esq., Senior Attorney
Southern Environmental Law Center
200 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

A P P E A R A N C E S Cont'd.:

CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES II AND III:

Christina D. Cress, Esq., Partner
Douglas E. Conant, Esq., Associate
Bailey & Dixon, LLP
434 Fayetteville Street, Suite 2500
Raleigh, North Carolina 27601

FOR CAROLINA UTILITY CUSTOMER ASSOCIATION and FOR TECH CUSTOMERS:

Matthew B. Tynan, Esq.
Brooks Pierce
Post Office 26000
Greensboro, North Carolina 27420

Craig Schauer, Esq.
Brooks Pierce
1700 Wells Fargo Capitol Center
150 Fayetteville Street
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd.:

FOR CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION:
John D. Burns, Esq., General Counsel
811 Ninth Street, Suite 120-158
Durham, North Carolina 27705

FOR BRAD ROUSE:
Brad Rouse, Pro se
Brad Rouse Consulting
3 Stegall Lane
Asheville, North Carolina 28805

FOR CLEAN POWER SUPPLIERS ASSOCIATION:
Ben Snowden, Esq., Partner
Erin Catlett, Esq., Associate
Jack Taggart, Esq., Associate
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd.:

FOR THE ENVIRONMENTAL WORKING GROUP:
Andrea C. Bonvecchio, Esq.
The Law Offices of F. Bryan Brice, Jr.
127 West Hargett Street, Suite 600
Raleigh, North Carolina 27601

Carolina Leary, Esq.
1250 I Street Northwest, Suite 1000
Washington, DC 20005

FOR WALMART INC.:
Carrie H. Grundmann, Esq., Member
Spilman Thomas & Battle, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, North Carolina 27103

FOR CITY OF CHARLOTTE:
Karen Weatherly, Esq., Senior Assistant City Attorney
600 East Fourth Street
Charlotte, North Carolina 28202

A P P E A R A N C E S Cont'd.:

FOR APPALACHIAN VOICES:
Catherine Cralle Jones, Esq.
The Law Offices of F. Bryan Brice, Jr.
127 West Hargett Street, Suite 600
Raleigh, North Carolina 27601

FOR REDTAILED HAWK COLLECTIVE, ROBESON COUNTY COOPERATIVE FOR SUSTAINABLE DEVELOPMENT, ENVIRONMENTAL JUSTICE COMMUNITY ACTION NETWORK, and DOWN EAST ASH ENVIRONMENTAL AND SOCIAL JUSTICE COALITION:
Ethan Blumenthal, Esq.
ECB Holdings LLC
1624 Nandina Comers Alley
Charlotte, North Carolina 28205

FOR NC WARN and
FOR CHARLOTTE-MECKLENBURG NAACP:
Matthew D. Quinn, Esq.
Lewis & Roberts, PLLC
3700 Glenwood Avenue, Suite 410
Raleigh, North Carolina 27612

A P P E A R A N C E S Cont'd.:

FOR BROAD RIVER ENERGY, LLC:
Patrick Buffkin, Esq.
Buffkin Law Office
3520 Apache Drive
Raleigh, North Carolina 27609

FOR KINGFISHER ENERGY HOLDINGS, LLC, and
FOR PERSON COUNTY, NORTH CAROLINA:
Patrick Buffkin, Esq.
Buffkin Law Office
3520 Apache Drive
Raleigh, North Carolina 27609

Kurt Olson, Esq.
The Law Office of Kurt J. Olson, PLLC
Post Office Box 10031
Raleigh, North Carolina 27605

FOR NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION:
Tim Dodge, Esq., Regulatory Counsel
3400 Sumner Boulevard
Raleigh, North Carolina 27616

A P P E A R A N C E S Cont'd.:

FOR THE CITY OF ASHEVILLE and COUNTY OF BUNCOMBE:

Jannice Ashley, Esq., Senior Assistant City Attorney
City Attorney's Office
70 Court Plaza
Asheville, North Carolina 28801

Curt Euler, Esq., Senior Attorney II
Buncombe County
200 College Street, Suite 100
Asheville, North Carolina 28801

FOR MAREC ACTION:

Bruce Burcat, Esq, Executive Director
MAREC Action
Post Office Box 385
Camden, Delaware 19934

Kurt J. Olson, Esq.
Law Office of Kurt J. Olson, PLLC
Post Office Box 10031
Raleigh, North Carolina 27605

A P P E A R A N C E S Cont'd.:

FOR TOTALENERGIES RENEWABLES USA, LLC, and
FOR CLEAN ENERGY BUYERS ASSOCIATION:
Joseph W. Eason, Esq.
Nelson, Mullins, Riley & Scarborough LLP
4140 Parklake Avenue, Suite 200
Raleigh, North Carolina 27612

Weston Adams, Esq.
Nelson, Mullins, Riley & Scarborough LLP
1320 Main Street, Suite 1700
Columbia, South Carolina 29201

FOR PORK COUNCIL:
Kurt J. Olson, Esq.
Law Office of Kurt J. Olson, PLLC
Post Office Box 10031
Raleigh, North Carolina 27605

FOR COUNCIL OF CHURCHES:
James P. Longest, Jr., Esq.
Duke University School of Law
Box 90360
Durham, North Carolina 27708

A P P E A R A N C E S Cont'd.:

FOR AVANGRID RENEWABLES, LLC:
Benjamin Smith, Esq.
Todd S. Roessler, Esq.
Joseph S. Dowdy, Esq.
Kilpatrick Townsend & Stockton LLP
4208 Six Forks Road, Suite 1400
Raleigh, North Carolina 27609

FOR SEAN LEWIS:
Sean Lewis, Pro se
640 Firebrick Drive
Cary, North Carolina 27519

FOR THE USING AND CONSUMING PUBLIC, THE STATE, AND ITS CITIZENS:
Margaret Force, Esq., Special Deputy Attorney General
Tirrill Moore, Esq., Assistant Attorney General
North Carolina Department of Justice
Post Office Box 629
Raleigh, North Carolina 27602

A P P E A R A N C E S Cont'd.:

FOR THE USING AND CONSUMING PUBLIC:

Lucy Edmondson, Esq., Chief Counsel
Robert Josey, Esq.
Nadia L. Luhr, Esq.
Anne Keyworth, Esq.
William E.H. Creech, Esq.
William Freeman, Esq.
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

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. Good morning. Let's go back on the record, please. Walmart, you're up.

MS. GRUNDMANN: Thank you, Chair Mitchell.

Whereupon,

SAMMY ROBERTS AND MAURA FARVER,

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

CROSS EXAMINATION BY MS. GRUNDMANN:

Q. Good morning, panel, my name is Carrie Grundmann on behalf of Walmart. I have a couple of questions that I think are predominantly for Mr. Roberts, and I hope it's just a couple of questions.

Yesterday, in response to some questions from counsel for Avangrid, I think you indicated that the, sort of, preliminary results from the NCTCP weren't sufficient to, sort of, evaluate the location for interconnecting offshore wind and that an actual interconnection study needed to be conducted; is that fair?

A. (Sammy Roberts) Yeah. I would say that the

NCTPC offshore wind study results are directionally correct. However, in order to know the true network upgrades that need to be constructed for injecting a certain megawatt level, you would have to put in an interconnection request into a DISIS study.

Q. And that -- by network upgrades, you mean any upgrades, network transmission, sort of all of the above what would be necessary to interconnect that particular project?

A. Yes, that's correct.

Q. Okay. And is it fair to say that, of the three parcels of offshore wind off the coast of North Carolina, that none of the three of those have entered DISIS in 2022?

A. That is correct.

Q. And the earliest they could enter would be January 1, 2023?

A. That's the next DISIS enrollment window.

Q. And so whether it is the Avangrid total or Duke affiliate facility, at this point in time the Company does not know definitively the costs associated with interconnecting any one or more of those particular parcels of offshore wind?

A. Right. Based on using the NCTPC study as directionally correct, saying New Bern is the preferred point of interconnection, we have conducted internal analysis to look at what it would take to interconnect to New Bern. And those numbers were provided in a data request comparing that against other points of interconnection.

Q. And when you studied that connecting to New Bern, did you study that based on one particular parcel of land?

A. No.

Q. Okay. Thank you, sir. Those are all the questions that I have.

CHAIR MITCHELL: All right. Mr. Josey?

CROSS EXAMINATION BY MR. JOSEY:

Q. Good morning, Ms. Farver, Mr. Roberts, I'm Robert Josey with the Public Staff. Let's stick with offshore wind for a moment.

Mr. Roberts, you were just discussing the need for a DISIS interconnection study for the wind project.

Is Duke anticipating studying the point of -- requesting a point of interconnection in New Bern at this point?

A. That's correct. We have it in our Near-Term

Action Plan to submit a generator interconnection request with the point of interconnection being New Bern.

Q. And I believe you said yesterday that interconnecting into New Bern would require the transmission line from New Bern to Raleigh to be upgraded from a 230 kV line to a 500 kV line; is that right?

A. So based on an informal analysis, no. I mean, it depends on the megawatt level. So if you're looking to connect, this is what we had in our stakeholder meeting on one of the slides. I believe it's the March stakeholder meeting. That if you want to connect 1,600 megawatts of offshore wind into New Bern, you would need a 500 kV line.

Q. Okay. So if it's just Duke Energy requesting interconnection into that line or an offshore wind facility, then it may not need to be upgraded from 230 to 500; but if either of the other potential facilities were to request an interconnection there, it would need to be a 500 kV line?

MS. KELLS: Objection. Chair Mitchell, Mr. Roberts' testimony doesn't really get into the different parcels and amounts of those.

MR. JOSEY: I think it's common knowledge and been testified at this point how many megawatts are looking to interconnect into that particular point of interconnection based off of the 2022 NCTPC study.

CHAIR MITCHELL: All right. I'm gonna overrule the objection. Ask your again so that he may answer it.

Q. I'll ask it another way. If there were more than the 800 megawatts of offshore wind looking to interconnect into the New Bern substation, would that line need to be upgraded from 230 to 500?

A. Yeah. I mean, based on informal analysis and looking at the results of the 2022 DISIS where some of the solar is requesting interconnection, if a lot of that solar interconnects, then you could possibly need a 500 kV line above that amount.

Q. Okay. And just because you touched on the solar that could possibly interconnect to that line in the 2022 DISIS, that is -- that line is outside the red zone currently, correct?

A. That's correct.

Q. Okay. And if the line were to be upgraded from a 230 to a 500 kV line, would it -- was that completely rebuilding a new line or is that considered an upgrade?

A. Yeah. So what we're reflecting and reflected in the stakeholder meeting, in Appendix P, is that you would need a new 500 kV line, for which we already have substantial right of way. But it would be a new 500 kV line from New Bern to Womack to Wake.

Q. And do you know if needing that new -- building a new 500 kV line along that corridor would require a CECPCN by this Commission?

A. So I think it would require a CPCN or CEPCN. I mean, you're gonna most likely have to require a right-of-way extension for a portion of that 500 kV line.

Q. Okay. Thank you. And to your knowledge, do you know if Duke Energy Renewables, who owns the facility at this time, or owns the lease parcel, intends to enter into the 2023 DISIS?

A. I will defer that to the Long Lead team.

Q. Okay. But there's nothing stopping Duke Energy Renewables from submitting an interconnection request?

A. Not to my knowledge.

Q. And if this facility were to enter into the

2023 DISIS, is there -- what would be the requirements for it to continue through the study process and remain in the baseline in order to reserve its spot for the capacity on the line?

MS. KELLS: Chair Mitchell, could counsel clarify which facility?

MR. JOSEY: The Duke -- the Duke facility.

THE WITNESS: So you're saying if offshore -- the Duke Energy Renewables submitted an interconnection request to the 2023 DISIS, how would it retain its location or spot?

Q. It's spot in the queue process in the baseline for future DISIS studies. I think we've heard testimony to this point that states that it's gonna take a while to build this facility, if it enters the study process.

A. Ms. Farver is more familiar with the DISIS process.

A. (Maura Farver) So subject to check, to maintain eligibility in DISIS, there are different requirements for phase 1, phase 2, and beyond. One of the ways that you can demonstrate readiness is to put down deposits. And so because it would be for jurisdictional, it could meet the eligibility with deposits along the way.

Q. Okay. And would it need to interconnect within a year or two after the study process is complete in order to remain in the baseline?

A. I would want to double-check this, but I believe, once the interconnection agreement is signed, that stipulates the timeline for when it would interconnect. And then there are requirements and milestones associated with that.

A. (Sammy Roberts) Any necessary upgrades resulting from the study and postulated in the interconnection agreement would have to be complete before it could be commercial.

Q. Okay. And there -- is there a suspension provision in the open-access transmission tariff that would allow it if -- to wait?

A. (Maura Farver) I believe there is a suspension provision for FERC jurisdictional projects, yes.

Q. Thank you. And I believe this is for Mr. Roberts.

If DEP were to own the offshore wind facility and run an underwater transmission line to the point of interconnection in New Bern, would that underwater line be subject to DEP's open-access transmission tariff allowing other -- well, answer that question first.

A. (Sammy Roberts) Okay. So the submerged cable -- I can let the Long Lead-Time speak more to that, but I'll just go on record as saying it's longer coming from one lease area than it is from the other, based on the New Bern point of interconnection. But once you get to the landing there's what we call onshore interconnection facilities, transmission line that needs to be built to get from the landing to New Bern.

And so that would be part of the interconnection facility, so that would be the responsibility of the generator owner.

Q. Okay. But I guess my question is, is that line from the offshore wind facility itself, if it is owned by Duke Energy Progress, is it subject to open-access transmission and therefore interconnection into that line from other facilities like any other part of the grid?

A. Right. I'll let the Long Lead-Time group speak to this. I'll defer the question to them. The only thing I would offer is that the interconnection facilities can be one submerged cable, it can be two submerged cables, it can be three submerged cables, depending on the megawatt level. And to get from the landing to New Bern, you're gonna have to have high-voltage DC as part of those interconnection facilities.

But once again, that's part of the facilities study for determining the interconnection facilities required, and it's also the responsibility of the generator owner.

Q. Okay. So you're saying you're not sure whether or not another facility, such as Total or the Kitty Hawk project by Avangrid, could interconnect directly into the line from the facility -- from Duke's offshore wind facility in between those point of interconnection?

A. Right. Once again, I'll defer to the Long Lead-Time group. They would be more familiar with that. But that submerged cable is not part of the revenue requirement associated with our transmission tariff, if that answers your question.

Q. All right. Thank you.

A. (Maura Farver) I was just gonna ask, is the question to determine where the demarcation is between interconnection facilities and the network?

Q. Yeah. The point of the question is to try to figure out whether or not any DEP-owned transmission line is subject to an open-access transmission tariff allowing other facilities to interconnect to it just like any other transmission line on the system?

A. (Sammy Roberts) No, it's not part of -- it's not network transmission. So it's not governed by our tariff with respect to our revenue requirement. It is governed by the LGIP process, and the interconnection facility's a piece of that.

Q. All right. Thank you. We'll switch topics to off-system purchases.

You stated, on page 59 of your testimony, that Duke and PJM studied the possibility of a 1,500-megawatt firm transfer from PJM to DEP at an estimated cost of $700 million; is that correct?

A. That's correct. We -- we coordinated with PJM, used their PJM deliverability -- generation deliverability tool, used their data, and that was a piece of the study. We also looked at effected system studies that had been done, and we looked at the NITS or network integration transmission service piece, the network upgrades on the DEP side we be needed.

And based on that analysis, we got to $700 million projects, and I'm -- subject to check, I believe it was around 84 months to construct the upgrades.

Q. Okay. And the upgrades for that transfer, would they be partially on PJM's transmission system as well?

A. Yes.

Q. Okay. And would Duke Energy ratepayers be responsible for paying those costs?

A. So my understanding, subject to check, is that PJM can charge a special rate with respect to those upgrades, or they can charge their border rate for point-to-point. And I think we show in Appendix B that order rate keeps climbing. I think we assumed 5 percent per year, but it's more than that.

But that border rate keeps on increasing as they keep on building transmission in their system and incorporating that into their border rate. So we would have to pay that border rate. So, for example, 1,000 megawatts at the 2021 rate, I believe it is, would be $67 million per year.

Q. And that money recovered by Duke Energy ratepayers would be to improve the PJM grid, correct?

A. Yes. I mean, it would improve the PJM grid, but you're improving that grid to be able to import 1,000 megawatts.

Q. And is -- Mr. Roberts, are you aware of Duke Energy Progress' intentions to upgrade the Greenville-Everetts line?

A. Yes.

Q. And is that a part of this plan?

A. No, that is not part of the plan.

Q. That's separate?

A. Separate, yes.

Q. And for the off-system purchases, such as the onshore wind or any purchases that may come through these tie lines that we were just talking about, were they given a transmission cost adder or proxy?

A. So yes. We actually took the border rate and converted that to a dollar per kW year, and once again escalated that in time based on past increases PJM had been charging for their border rate.

Q. And those off-system transmission cost adders, they include the wheeling fees as well for the off-system purchases?

A. So that border rate would be the wheeling fee, and then you've got the -- you got the cost of the resource. You know, Duke Energy's gonna own the resource in Ohio somewhere. You know, you got that cost as well. The modeling team could speak to that.

Q. Okay. And if you were -- if Duke Energy were to have to own onshore wind or onshore wind in the Midwest, MISO, for instance, it would have to pay wheeling charges for MISO and through PJM to get it to the Duke Energy grid?

A. That's correct.

Q. Okay. And so when we're talking about the cost adder -- the transmission cost adders and comparing on-system purchases to off-system purchases, it's not really an apples-to-apples comparison, is it?

A. That's correct, it's not.

Q. Thank you. Okay. I have a couple questions about the red zone upgrade projects.

Are the RZEP projects, are they -- they're considered local transmission projects; is that correct?

A. That's correct.

Q. Okay. And that's why Duke Energy is proposing them through the NCTPC process?

A. That's correct.

Q. And you mention, on page 22 of your

testimony, that the RZEP projects will be subject to the attachment in one planning process, correct?

A. That's correct.

Q. And that's an attachment to Duke Energy's joint open-access transmission tariff?

A. That's correct.

Q. And Section 4 of Attachment N-1 states that the local transmission plan will identify local transmission projects or local projects. And a local project is defined as a transmission project that is, one, located solely within the combined Duke Progress -- I assume that means Duke Energy Carolinas, Duke Energy Progress -- transmission system footprint; and, two, not selected in the regional transmission plan for the purposes of regional cost allocation.

A. That's correct.

Q. Okay. And so did the RZEP projects, did Duke Energy request selection in the regional transmission plan at SERTP?

A. No, we didn't. If those projects get included in the NCTPC local transmission plan, they would automatically flow into the SERTP model.

Q. But as I read how Section 4 of Attachment N-1 reads, if I read it correctly, it has to go to SERTP first and not be selected as a SERTP project before it comes to the NCTPC?

A. That's not my understanding of how the local transmission planning process works in according with Attachment N-1.

Q. Okay. And subject to check, Section 7 of Attachment N-1 is the transmission cost allocation for local projects, but it only provides cost allocation methods for joint local reliability projects and joint local economic projects; is that correct?

A. Subject to check.

Q. Okay.

MS. KELLS: Chair Mitchell, can we ask if the witness needs a copy of N-1?

MR. JOSEY: Fair enough. Chair Mitchell, at this time, I would ask to enter into evidence our -- and mark for identification Public Staff Transmission Panel Direct Cross Exhibit 1, which is excerpts from the joint open-access transmission tariff of Duke Energy Carolinas, Duke Energy Florida, and Duke Energy Progress.

CHAIR MITCHELL: All right. Hearing no objection, I'll allow you-all to -- we'll get in entered into the record, but can you give it to counsel first, just so they can look at it and make sure, since it's excerpts, before you hand it on to the witness.

(Pause.)

CHAIR MITCHELL: Counsel for Duke, when y'all are okay with it, just give me a signal.

(Pause.)

MS. KELLS: It's okay. Looks okay to us.

CHAIR MITCHELL: All right. The document will be marked for identification as Public Staff Transmission Panel Direct Cross Examination Exhibit 1.

(Public Staff Transmission Panel Direct Cross Examination Exhibit 1 was marked for identification.)

MS. KELLS: Chair Mitchell, can counsel clarify that this came from the OASIS site?

MR. JOSEY: Yes, it was download from Duke Energy Progress OASIS website.

CHAIR MITCHELL: Mr. Josey, on what date did y'all download it; do you recall?

MR. JOSEY: I don't recall.

CHAIR MITCHELL: Time frame, would it

have been within the past week or two weeks?

MR. JOSEY: I would say the past several months. It's been on my desktop for a while.

CHAIR MITCHELL: Okay. All right. The witness has had a chance to look at it. Mr. Josey, please proceed.

Q. Mr. Roberts, if you could pull up to the last page of the excerpt I gave you, and this is just Section 7, as we were talking about, discussion titled "Transmission Cost Allocation for Local Projects." And Section 7.1 says, "With the exception of joint local reliability projects and joint local economic projects, nothing in this attachment is intended to alter the cost allocation policies of the tariff."

A. That's what it says.

Q. Yes. And so is -- are the red zone upgrade -- is the red zone upgrade expansion plan projects, are they considered reliability projects or economic projects?

A. They're considered generator addition projects/public policy projects.

Q. Okay. And so there is no cost -- specific cost allocation method for these projects contained within this attachment?

A. Within this attachment, no. But as far as, you know, it says will not alter the cost allocation policies of the tariff. That means that they would be allocated as any project that goes into the base plan.

Q. And any project that goes into the base plan for DEP or DEC is allocated wholly to either DEP or DEC?

A. To the transmission owner; that's correct.

Q. Okay. And so to your knowledge, there's no ability for Duke to allocate cost of these projects across DEP and DEC?

A. I believe the panel that Ms. Bateman and Mr. Peeler were on spoke to that. But to my knowledge today, there is no cost allocation methodology to spread those costs across DEC and DEP.

Q. Okay. Thank you. Okay. As far as the determination -- Duke's determination for projects that it included in the red zone expansion plan, was there anything, other than the amount of study request or interconnection request into each line, that went into the evaluation of whether or not to put those specific projects in the plan?

A. Yes. So I'll go through a little bit of history, because I think it's important. Back in the -- 2021, I believe it was October time frame, technical conference on the 2020 IRP, that's when Duke first introduced -- yeah, we made a great stride with respect to this DISIS process, this first ready, first served process and cluster studies. And this will help manage an efficient queue going forward.

But it was also pointed out that, even though it distributes cost allocation among multiple projects versus the serial queue was the first to cause, you still can have issues with respect to insurmountable network upgrade hurdles that developers don't want to find answer or can't meet a certain cost number, et cetera. And so they withdraw.

And that's exactly what happened in the transition cluster study for DEP, is I think you're down to a hundred and -- subject to check, around 180 megawatts of projects now, two projects. So, you know, exactly what we thought would happen or could happen happened with that transition cluster study.

And so in that 2020 IRP technical conference, we also showed a map, and we showed these are common hurdles that are creating inefficiencies with getting generator solar to interconnection, to an interconnection agreement. And we're gonna have to address those. And we need to address those with a proactive transmission planning process.

And that's -- you know, long story short, that's exactly what we're trying to do with the RZEP projects. And the mechanism that FERC has approved to facilitate such projects, getting them into the base plan, is through the NCTPC.

Q. Okay. And so as you were just stating, there were multiple interconnection requests into these areas they were unable to interconnect due to the large interconnection cost, and so that is what Duke Energy looked at in determining which projects would go into the plan?

A. It's that, it's knowing with the 2020 IRP portfolios, the magnitude of solar that were in those portfolios, the magnitude of solar in the Carbon Plan. You know, that factors into that. And there's -- if you do nothing, other red zones are gonna be created and you're gonna have issues in other areas with red zones, congestion.

And so what we did is we looked at what are the most common upgrades that are being hit by these solar projects requesting interconnection. And so that was our initial mapping that we did, studies versus red zone projects. Then we went one step further and, you know, through communications with Public Staff, we agreed on a scope, and we conducted a supplemental study of 5.4 gigawatts of solar. 1,900 in DEC and 3,500 in DEP.

Q. Okay. The Public Staff appreciates that Supplemental study. But and I think it should be made clear here that it is the ratepayers that will ultimately bear the cost, either from the interconnection upgrades due to the 2022 solar procurement or the red zone upgrades, correct?

A. Yeah. All transmission customers will share in the cost.

Q. The transmission customers will -- well, transmission customers as in wholesale and retail, correct?

A. That's correct.

Q. All right. So is there -- when Duke Energy is looking at including a project in this red zone expansion plan or any future red zone expansion plans, is there any -- any cost that would be prohibitive to including it in the plan?

A. Right. So as provided, a cost benefit -- in testimony, a cost benefit analysis was done, and we used the asset management model. And it showed with the age of these assets and a probability distribution associated with, you know, the potential to -- the likelihood of impacting customer outages, that there was a positive cost benefit. And that's just one area. Didn't consider the renewable benefit, the clean energy benefit associated with what these projects would provide.

And I think I stated yesterday in my testimony that these red zone projects should facilitate larger projects, solar projects interconnecting to the system, and that has a cost benefit as well. Or excuse me, a benefit. Net benefit.

Q. And as you just stated, and as you stated -- I guess you stated yesterday that there will be need for more upgrades in the future on top of this red zone expansion plan; is that correct?

A. That's correct. We look at this as the first phase and -- but the first phase, but a necessary phase with respect to executing the Carbon Plan.

Q. Okay. And will Duke Energy consider whether a line has been recently upgraded in the past in determining if that line should be upgraded again, or will it only consider the number of interconnection requests that are submitted for that line?

A. Right. I think this was covered yesterday in live testimony as well in that, you know, based on the transmission planning engineer's judgment and standard conductor, standard poles, et cetera, you know, I think I referenced the Cape Fear west end line where we would go from a single conductor, 1,272 cmil to a bundle of 1,590 cmil, and thus increase that MVA carrying capability by 121 percent.

Q. And again, you may have stated this, sorry if it's been -- it's asked again, but are you -- do -- does Duke consider the red zone projects to be necessary for reliability purposes?

A. So to reliably deliver the solar to load centers, yeah. I mean, the ultimate beneficiary are the customers, right? I mean, if you can't -- if you had to curtail the solar to manage power flows, that's not executed in the Carbon Plan and it's not benefitting the customers to build a resource that they can't be served by.

Q. And so while Duke Energy is presenting the red zone expansion plan as a public pol- -- public policy projects, they could be considered reliability projects as well?

A. Reliability in the sense of firm deliverability of that resource to the load, yes.

Q. And you are generally aware that Duke Energy is considering merging the balancing authorities between DEP and DEC?

A. Yes. That's -- Mr. Peeler and Ms. Bateman spoke to that.

Q. And would -- could that possibly alleviate some of the need for these red zone upgrades?

A. I would say no. And, you know, given the transmission system, if you connect solars in those areas, they're gonna get those specific red zone projects with respect to an increase in line loading where contingency overloads that line.

Q. But it has -- has it been studied? Has Duke Energy done a formal study to determine interconnections when looking at both DEP and DEC balancing authorities as one?

A. We've discussed that, you know, with respect to interconnecting resources. And, you know, only when you look at things like if you had all the solar in DEP, for example, or you had all new replacement generation, or a large portion of replacement generation in DEC and you needed to get that load in DEP, only in those situations would you need to look at more capability between the systems -- being implemented between the systems.

I'll give you an example. So if we retired Roxboro plant and we didn't replace that generation on site, and we located the replacement generation in the DEC area. Even if we're merged, we would still probably need to build -- well, I would say we will need to build some transmission to get that generation from that legacy DEC area over to the legacy DEP load.

And it would probably be -- I think I referenced this in the Appendix P, it would probably be in the form of a new 230 line, a new 500 kV line and a new 500 to 230 kV transformer station.

Q. And so that would be on top of the red zone upgrades, on top of the interconnection, or the upgrades needed to bring in all system purchases and on top of the upgrades for the wind facilities?

A. That's correct. However, you know, that's one of the reasons we're promoting proactive transmission planning in this testimony, is that we've got to look at all that holistically. And then there's gonna be some assumptions made about where replacement generation is gonna be located that will impact that transmission as well.

Q. Thank you. And so as this red zone expansion plan goes through the NCTPC approval process, could you just give a quick narrative of how that's going to proceed if the Commission were to acknowledge?

A. So in a parallel path, we're gonna present the results of the supplemental study, how we conducted it, et cetera. We're gonna present that to the TAG. And subject to check, I think that meeting is around October 19th or 9th. Maybe 9th. Subject to check.

But anyway, at the next TAG meeting -- excuse me. At the next TAG meeting we're gonna present the supplemental studies and the results and -- sorry. Receive feedback. And then, ultimately, hopefully we will get to December, have that in the annual local transmission plan, and then have the OSC vote on that. The TAG will get to review the draft report, provide feedback, and then a final report will be issued in January next year.

Q. And when you say the final report, that's from the Oversight Steering Committee, not the TAG, correct?

A. With TAG input, yes.

Q. Yes, with TAG input.
A. That's correct.
Q. My understanding from your discussions with other parties yesterday is that TAG is basically -- or the Transmission Advisory Group is basically the place for stakeholder input, which then is taken to the Oversight and Steering Committee, which then votes on whether or not to approve the local transmission plan; is that correct?
A. For the most part that's correct.
Q. And are you currently on the Oversight Steering Committee, or OSC?
A. Yes, I am.
Q. Okay.
A. I would not be the primary voting member, though.

MR. JOSEY: Chair Mitchell, at this time, I'd like to introduce and mark for identification Public Staff Transmission Panel Direct Cross Exhibit 2. And this is the scope document for the Oversight Steering Committee.

(Pause.)

CHAIR MITCHELL: All right. We will label the document for identification purposes as

Public Staff Transmission Panel Direct Cross Examination Exhibit 2.

(Public Staff Transmission Panel Direct Cross Examination Exhibit 2 was marked for identification.)

Q. Okay. Mr. Roberts, could you let me -- I guess, first of all, this does appear to be the scoping document that, kind of, determines how the Oversight Steering Committee proceeds in its process?

A. Yeah. I mean, I will state on the record that the FERC-approved governing process is in our OATT in Attachment N-1.

Q. Correct. So this is basically regurgitated in the OATT, or was pulled from the OATT?

A. This should be reflective of the OATT.

Q. Okay. Great. And on the back page, this is just a list of the people on the Oversight and Steering Committee as of yesterday, September 19, 2022?

A. That's correct.

Q. Was there a meeting yesterday?

A. I believe there was. I did not attend it, no.

Q. I was gonna say, you're a busy man. Okay. And so on page 2, under the heading "Membership," it states that, "The OSC will consist of eight appointed members plus ex officio members as approved by the OSC. And Duke Energy Carolinas, Duke Energy Progress, Electricities, and NCEMC shall each appoint two members to the OSC and may appoint up to two alternate members."

A. That's correct.

Q. That's correct. Okay. So Duke Energy has half of the members -- the voting members for the OSC, correct?

A. That's correct.

Q. Okay. And on page 5 under "Voting" it states that, "Members of the OSC shall use reasonable good faith efforts to reach decisions via consensus. However, in the event that the OSC is unable to reach a decision by consensus, then a decision will be reached by a majority vote," correct?

A. That's correct.

Q. Has the OSC ever not reached a consensus, to your knowledge?

A. I mean, I'm -- I don't have a long history with the NCTPC. In the history that I do have, I have not heard of not reaching consensus.

Q. And so -- and to your knowledge, Duke Energy

Progress and Duke Energy Carolinas have never voted in opposite directions on a plan; they've never conflicted?

A. Like I said, with my history, I've not noticed that NCMC, Electricities, Duke Energy Progress, and Duke Energy Carolinas have not voted inconsistent.

Q. Okay. And to your knowledge, do you know -- well, to go down a little further, it says that, "In the event of a tie vote, the OSC shall retain an independent third party who will provide a recommended decision based on a review of the issue in dispute."

Do you see that?

A. Yes.

Q. Okay. Are you aware -- I mean, you just said that you're unaware of any vote that was not a consensus, so I assume you are not aware of any time a third party has been retained to --

A. Based on my limited history, and my understanding is there's always an independent entity that administers the process for the NCTPC.

Q. Okay. And then down in the next paragraph on page 6, middle of the page, it says, "It is anticipated that all parties will abide by the decisions of the OSC; however, any NCTPC participant or TAG participant may request that the NC -- the North Carolina Utilities Commission Public Staff render a nonbinding opinion with regard to any dispute -- disputed decision of the OSC and any decision of the investor-owned utility superseding a decision by the OSC."

And to your knowledge, that's never taken place either, correct?

A. Not that I'm aware of.

Q. And sorry to jump around a little bit, but we'll go back up to the top paragraph on page 6, on the second line where it starts, "However, the investor-owned utility shall not be bound by the decisions of the OSC to the extent that the investor-owned utilities reasonably determine such decisions as related to reliability planning and that are inconsistent with good utility practice or SERC- or NERC-established criteria, or least cost integrated resource planning principles."

Is that correct?

A. That's what it reads.

Q. Okay. So if Duke Energy determines that the red zone expansion plan projects are necessary for reliability purposes, whether the OSC agrees with them or not, Duke can go ahead with those upgrades, correct?

A. So I think that what this is referring to -- you know, usually when we talk about reliability projects in the NCTPC world and in the Duke Energy transmission planning world, we're talking about projects resulting from TPL-001 NERC standard studies. And so those projects are projects required by the standard to be implemented to meet those reliability standards.

Q. Okay. Thank you. And just a few more questions on -- I think this one could be for either of you. The projects that are in the DISIS process right now, do you know the percentage of transmission projects to distribution projects?

A. Off the top of my head, no.

Q. Would you say there are more transmission projects than distribution projects?

A. Megawatt-wise, definitely; but number-wise, yes.

Q. Number-wise, yes, there are probably more --

A. Transmission --

Q. -- transmission --

A. -- connected projects.

Q. -- connected projects. Okay.

And did you hear the line of questioning

Mr. Kalemba answered on interconnection limits last week stating that the Duke limits -- that limits Duke is imposing are based off historical annual interconnections?

A. That was one of many reasons for the interconnection limits.

Q. Okay. And those historical interconnection limits were mostly based off of interconnecting small 5-megawatt projects onto the distribution system, correct?

A. Yeah. I believe, if I recall correctly, one of the intervenors spoke to connections in 2015 and 2017 interconnections. And those were -- a lot of those interconnections were distribution connected resources.

Q. And so understanding that the transmission interconnections are more complex, but interconnecting 750 megawatts of mostly 5-megawatt facilities would be substantially more facilities than interconnecting, you know, 70- to 80-megawatt or more facilities, correct?

A. And it's gonna take you a very long time to get to 70 percent.

Q. So -- okay. But all to say that there are -- you're connecting fewer facilities to get to

750 megawatts when you're talking about 951 projects that are mostly transmission interconnection --

A. Yeah.

Q. -- projects, correct?

A. Yeah, yeah. And that's another benefit of the red zone projects, is that you're enabling interconnection in areas where you can have larger solar facilities.

Q. Okay.

A. So for a given number of interconnections, you can connect more megawatts.

Q. Okay. And, Mr. Roberts, you stated in response to a question from Mr. Burns yesterday that the NCTPC process updates future generation resources in its base analysis; is that correct?

A. So I believe he asked about generation additions and retirements. Or I answered with generation additions and retirements. But yeah. So generation additions that -- and resulting transmission network upgrades have resulted from IAs, those are in the base reliability plan. Just like proposed projected generation retirements, if they're in an approved IRP or an approved Carbon Plan, that's studied in the base reliability model in NCTPC.

Q. Yeah. So as you just stated, if an IRP calls for a resource, the NCTPC will include it in its analysis; is that correct?

A. So if the IRP calls for a resource, if the location is known and the point of interconnection is known, then -- and megawatt size, then yeah, it can include it specifically in the model. But if it's -- like look at 2,000 megawatts of additional solar, than some assumptions have to be made as far as location and size.

Q. And the NCTPC released a study scope document a few months ago; is that correct?

A. Subject to check, yes.

Q. Yes. Okay. We'll get there.

MR. JOSEY: At this time, Chair Mitchell, I would like to present and have marked for identification Public Staff Transmission Panel Direct Cross Exhibit 3, which is the 2022 NCTPC study scope document.

CHAIR MITCHELL: All right. The document will be marked for identification as Public Staff Transmission Panel Direct Cross Examination Exhibit 3.

(Public Staff Transmission Panel Direct

Cross Examination Exhibit 3 was marked
for identification.)

Q. Mr. Roberts, could you flip to page 5 of this document, please.

And does this -- according to this page, the study scope, it includes two Roxboro combined cycle plants totalling 2,700 megawatts?

A. That's correct.

Q. In the 2032 to 2033-W?

A. Yeah, the winter case.

Q. Yeah. And so you're generally aware that the Public Staff had Duke run a SP5 model --

A. Yes.

Q. -- for this proceeding?

And that those two combined cycles in that model were not at the Roxboro location?

A. That's correct.

Q. Okay. So how would the NCTPC process update facility additions or subtractions that are called for in the Commission's approved Carbon Plan, particularly if it didn't have these facilities in that location?

A. Right. So what you're -- I mean, what you're seeing here is reflective of the current plan. These are actual solar interconnections that are included, you can see, in 2027 summer case. And so Roxboro CC, if the Carbon Plan that's approved, says 2,700 megawatts of CC in DEC for meeting DEP resource planning requirements, then once again, you're talking about some substantial transmission and greenfield transmission, and even these 2032, 2033 dates would be challenging.

Q. Okay. And I assume you're familiar with the Southeastern Regional Transmission Planning or SERTP?

A. Yes, I'm not a member of that group, though.

Q. Okay. And do you know if these two combined cycles at the Rox- -- at Roxboro were also presented to the SERTP at the same location?

A. I do not.

Q. Okay.

A. That file was recently submitted back in August, I believe, the SERTP.

Q. Okay. I believe this is for Ms. Farver. Last question.

Do you -- does Duke believe its petition to separately acquire CPRE capacity through the 2022 solar procurement will result in lower cost to ratepayers?

A. (Maura Farver) Lower cost as opposed to what?

Q. As opposed to just including them as all -- as acquiring them all through 951 like every other project.

A. Thank you. I am not sure that there's going to be a cost difference as to whether or not megawatts are tagged as CPRE versus 951 megawatts. They're still part of the same bid process, they have the same contract structure, duration. So I don't see a difference in the price. But since we still have an outstanding legal obligation to fulfill the CPRE target, that was the motivation for proposing it -- excuse me -- that was the motivation for proposing seeking those megawatts through the bids that have already been received for the solar procurement.

Q. Okay. Thank you. No further questions.

CHAIR MITCHELL: All right. Redirect?

MS. KELLS: Yes, thank you.

REDIRECT EXAMINATION BY MS. KELLS:

Q. Mr. Roberts, in your testimony yesterday, do you recall when counsel for Tech Customers asked you some questions about coal retirement?

A. (Sammy Roberts) Yes.

Q. And how much coal generation capacity are the Companies planning to retire by 2035?

A. Yeah, so as reflected in my testimony in witness Table 1, a little over 8,400 megawatts of winter capacity is planned to be retired by 2035.

Q. And what are the implications of those retirements, from a transmission perspective?

A. Yeah, so from a transmission perspective, some of this has been discussed, but if you can replace the resource on site, then -- and it's similar capability, then you're likely not to have transmission impact. In fact, the generation replacement process, that's part of the independent entity study, is to show there's no material impact to the transmission system with the replacement generation.

If you don't replace it on site, and we may see that the most cost-effective solution is not to replace it on site, then there's the timeline issue. For example, if you can't replace Roxboro on site and you had to build greenfield transmission; i.e., a new 500 kV line, or a new 230 kV line, a new 500 230 kV substation, transformer station, then that can add significant time to getting that replacement generation in place and being able to facilitate the retirement.

And then there's gonna be local impacts as well. For example, if you retire Roxboro, you're probably gonna need some substantial static VAR compensator in the area.

Q. All right. Thank you. And then also yesterday, counsel for CPSA asked you some questions regarding the time required to interconnect solar projects; do you recall that?

A. Yes.

Q. And he asked whether you agree that a project that does not need thermal upgrades could connect in one to two years; do you recall that?

A. Yes.

Q. Upon further reflection, do you still agree with that suggestion?

A. So reflecting on that, I did not agree with one to two years. It's -- and I think witness Kalemba discussed this as well in his testimony, but it's really around 26 to 32 months now. But we are looking to improve that process associated with getting the IA to getting COD.

Q. And then to follow up on that topic, you also had some questions about Duke's engagement with developers to improve the solar interconnection process.

Do you recall those questions?

A. Yes.
Q. In your view, has Duke already achieved significant amounts of solar interconnections to date?
A. Yeah, absolutely. We connected over 4,000 megawatts of solar, and we have 1,600 under construction. So we're nation leaders associated with interconnecting solar. So I'm -- I mean, I'm kind of proud of the amount of solar we've been able to connect over the last several years since the state tax credit.
Q. And even with that success, is Duke doing anything to improve in this area?
A. Yes. Like I was saying, we conducted some process improvement events. And through those process improvement events, we assigned actions to different groups such as engineering, looking at the engineering standards associated with the -- associated with the interconnection facilities. And they're running with that and looking to improve those standards. So if you could get that done in a more efficient manner with respect to interconnection facilities.
We're also looking at the standards. If you have a cookie-cutter approach with respect to these interconnection facilities, that can present efficiencies as well. There's several facets between

the getting interconnection agreement to COD with respect to the interconnection facilities that we're looking at with gaining efficiencies. And our target is an aggressive target, it's 20 months.

Q. Okay. And when does the Company plan to launch some of those efforts that it's been developing?

A. In 2022.

Q. Okay.

A. This year.

Q. That's right, '22 is this year. Thank you.

Counsel for CPSA also asked you some questions about the results of the supplemental studies for the red zone; do you recall that?

A. Yes.

Q. And in your testimony, you testify that both DEC and DEP study results reflected that the red zone projects were needed to enable about a total of 3,700 megawatts of projects to be interconnected; is that right?

A. That's correct.

Q. And by saying that the red zone projects will enable solar project interconnections, do you mean that if the red zone projects are done, Duke can go out and automatically interconnect those projects without any other upgrades?

A. No, I'm not saying that. So once again, these are common upgrades that a lot of generator interconnection requests have basically reflected overloads associated with these transmission lines. And because they're common to so many megawatts of solar requesting interconnection, it makes sense to go ahead and get these constructed in a proactive manner.

And so there will be other upgrades. Even the ones we evaluated in the supplemental studies outside the red zone are probably gonna need network upgrades. But also inside the red zone, there could be additional upgrades that are needed based on size and location of the solar that's requesting interconnection.

Q. Thank you. Just a couple questions from today, counsel for the Public Staff gave -- handed out the Cross Exhibit 2, the transmission planning collaborative OSC scope document. Do you have that?

A. Yes.

Q. It's the one with the list of -- the roster on the last page.

A. Yes.

Q. Would you agree that 4 of the 11 people

listed on that list are Duke personnel?
A. Yes.
Q. Okay. There's also three NCEMC personnel, correct?
A. That's correct.
Q. And three Electricities personnel, correct?
A. That's correct.
Q. Okay. And counsel for the Public Staff also asked you about -- a couple of questions about the solar interconnection abilities that Duke has included in the plan for 750 megawatts?
A. Yes.
Q. And he mentioned that, in the past, that was based on historical projects that were many more projects of much smaller size; do you recall that?
A. Yes.
Q. Could you explain why a fewer number of projects that are larger in size is much more complex to implement?
A. Yeah. So the interconnection facilities, themselves, if they're connecting to 230, there may be a ring bus that's needed associated that could take more time, line switches on 115 are needed. But outages, in general, for transmission projects, all of

those outages have to be coordinated. And it's not just interconnection outages -- interconnection facility outages or network upgrade outages.

You've also got maintenance outages, you've got asset management program outages, you've got unplanned outages, you've got NERC preventative maintenance required outages for relay maintenance, et cetera. So there are a lot of things that have to be considered with respect to these -- facilitating these interconnection facilities.

Q. Thank you. No more questions.

CHAIR MITCHELL: All right. The Commission is gonna defer questions for the panel to a later time. So with that, I'll take motions. And as we're taking motions, you-all may step down.

MS. KELLS: Chair Mitchell, the Company moves that -- Companies move that panels Exhibits 1 through 5 with Exhibit 5 being marked confidential to be accepted into the record at this time.

CHAIR MITCHELL: All right. Hearing no objection, that motion is allowed.

(Transmission Panel Exhibits 1 through 4 and Confidential Transmission Panel Exhibit 5 were admitted into evidence.)

MS. KELLS: And just to be sure, I'd like to also move that the summary of this panel's transmission summary of testimony be admitted into the record at this time.

CHAIR MITCHELL: It will be copied into the record as if given from the stand.

(Whereupon, the prefiled summary testimony of the Transmission Panel was copied into the record as if given orally from the stand in Volume 16 at the time their prefiled direct testimony was entered.)

CHAIR MITCHELL: All right. Mr. Josey.

MR. JOSEY: Thank you. Chair Mitchell, at this time, the Public Staff would ask that Public Staff Transmission Panel Direct Cross Exhibits 1, 2, and 3 be entered into the record.

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

(Public Staff Transmission Panel Direct Cross Examination Exhibits 1 through 3 were admitted into evidence.)

MR. BURNS: Madam Chair, CCEBA, at this time, would move that CCEBA Transmission Panel

Direct Cross Exhibit 1 be admitted into evidence.

CHAIR MITCHELL: All right. Motion is allowed.

(CCEBA Transmission Panel Direct Cross Examination Exhibit 1 was admitted into evidence.)

MS. CRESS: Chair Mitchell, at this time, CIGFUR II and II would move that its Transmission Panel Direct Cross Examination Exhibits 1, 2, and 3 be entered into the record.

CHAIR MITCHELL: Motion is allowed.

MS. CRESS: Thank you.

(CIGFUR II and III Transmission Panel Direct Cross Examination Exhibits 1 through 3 were admitted into evidence.)

MR. SMITH: Chair Mitchell, at this time Avangrid Renewables would move to enter Avangrid Renewables, LLC Transmission Panel Direct Cross Examination Witness Exhibit Number 1 into the record.

CHAIR MITCHELL: All right. Your motion is allowed.

(Avangrid Transmission Panel Direct Cross Examination Exhibit 1 was admitted into evidence.)

CHAIR MITCHELL: All right. Duke, call your next witnesses.

MS. LINK: Thank you, Chair Mitchell. For the record, my name is Vishwa Link, and Duke Energy calls the Long Lead-Time Resources Panel to the stand.

CHAIR MITCHELL: All right. Good morning, gentlemen. If you would, raise right hands, left hand on the Bible.

Whereupon,

REGIS REPKO, STEVE IMMEL, CHRIS NOLAN AND CLIFT POMPEE,

having first been duly sworn, was examined

and testified as follows:

CHAIR MITCHELL: All right. Whoever is -- oh, gosh. Whoever is sitting in the -- whoever is sitting in that last chair, please make sure you've got the microphone on and just be cognizant that you need to be facing towards the mic when you speak so that everybody in the room can hear you. Thank you. And hold it as close as -- get as close to the microphone as you can. All right, Mr. -- go ahead. Proceed.

DIRECT EXAMINATION BY MS. LINK:

Q. Good morning, gentlemen.
Beginning with Mr. Repko, would you please state your full name and business address for the record?
A. (Regis Repko) My name is Regis Repko. I am the senior vice president of generation and transmission strategy. My business address is 526 South Church Street, Charlotte, North Carolina 28202.
Q. And by whom are you employed and in what capacity?
A. I'm employed by Duke Energy as the senior vice president of generation and transmission strategy for Duke Energy Carolinas, LLC.
Q. And can you please briefly describe your role and responsibilities at Duke Energy.
A. I'm responsible for the execution planning, the technology determinations, and the procurements for generation, transmission, and fuels to meet Duke Energy's clean energy transformation goals.
Q. Thank you. Moving on to Mr. Immel.
Would you please state your full name and business address for the record?
A. (Steve Immel) Yes. My name is Steve Immel. My business address is 526 South Church Street,

Charlotte, North Carolina.

Q. By whom are you employed and in what capacity?

A. I'm employed by Duke Energy Carolinas, and I'm the vice president of generation transition strategy.

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

A. My team and I are responsible for identifying and integrating the various work streams associated with the orderly and executable transition of the generation fleet.

Q. Thank you. Turning to Mr. Nolan.

Would you please state your full name and business address for the record?

A. (Chris Nolan) My name is Chris Nolan. My business address is 13225 Hagers Ferry Road, Huntersville, North Carolina 28078.

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

A. I'm employed by Duke Energy Carolinas as the vice president of new nuclear generation strategy and planning.

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

A. I'm responsible for the leadership and direction of the strategy and planning for new nuclear generation. This role is inclusive of policy regulatory engagements, siting studies, and technology assessment.

Q. Thank you. And last but not lease, Mr. Pompee, would you please state your full name and business address for the record?

A. (Clift Pompee) My name is Clift Pompee. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

A. I'm employed by Duke Energy Carolinas, LLC as the managing director of generation technology.

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

A. Yes. I am responsible for providing leadership and direction for the review and awareness of new generation technologies, their domestic and global applications, functionality, performance, and potential application for Duke Energy. I also support the development of generation portfolios of technologies that ensure affordability for our customers, resource adequacy, energy sufficiency, and system reliability to achieve Duke Energy's carbon reduction goals.

Q. Thank you. Mr. Repko, did the panel cause to be prefiled in this docket direct testimony consisting of 57 pages and a summary?

A. (Regis Repko) Yes.

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

A. There was an error in my start date with Duke, but that was corrected in my rebuttal testimony.

Q. And if I were -- subject to that correction, if I were to ask you the same questions today that appear in the panel's prefiled direct testimony, would the answers be the same?

A. Yes.

Q. And the testimony does not include any confidential information, correct?

A. Correct.

MS. LINK: Chair Mitchell, I would ask that the Long Lead-Time Resources Panel direct testimony and summary be entered into the record as if given orally from the stand.

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

MS. LINK: Thank you.

(Whereupon, the prefiled direct testimony of Long Lead-Time Resources Panel of Regis Repko, Steve Immel, Chris Nolan, and Clift Pompee and the prefiled summary testimony of Long Lead-Time Resources Panel of Regis Repko, Steve Immel, Chris Nolan, and Clift Pompee were copied into the record as if given orally from the stand.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	**DIRECT TESTIMONY OF REGIS**
	)	**REPKO, STEVE IMMEL, CHRIS**
Duke Energy Progress, LLC, and	)	**NOLAN, AND CLIFT POMPEE**
Duke Energy Carolinas, LLC, 2022	)	**FOR DUKE ENERGY PROGRESS,**
Biennial Integrated Resource Plans	)	**LLC, AND DUKE ENERGY**
and Carbon Plan	)	**CAROLINAS, LLC**

TABLE OF CONTENTS

I. INTRODUCTION AND OVERVIEW

Q. MR. REPKO, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Regis Repko. My business address is 526 South Church Street, Charlotte, North Carolina, 28202.

Q. BEFORE INTRODUCING YOURSELF FURTHER, WOULD YOU PLEASE INTRODUCE THE PANEL.

A. Yes. I am appearing on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, the "Companies" or "Duke Energy") together with Steve Immel, Chris Nolan, and Clift Pompee on the "Long Lead-Time Resources Panel." Mssrs. Immel, Nolan, and Pompee will introduce themselves.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Carolinas, LLC as the Senior Vice President of Generation and Transmission Strategy for the Companies.

Q. WHAT ARE YOUR RESPONSIBILITIES AS THE SENIOR VICE PRESIDENT OF GENERATION AND TRANSMISSION STRATEGY?

A. In this role, I am responsible for the execution planning, technology determinations and procurements for generation, transmission and fuels to meet Duke Energy's clean energy transformation goals.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from Pennsylvania State University with a Bachelor of Science degree in Nuclear Engineering. My career began with Duke Energy in 1995 as an engineer at the Oconee Nuclear Station. I have held various roles of increasing responsibility including nuclear shift supervisor, operations shift manager, engineering supervisor, maintenance rotating equipment manager and superintendent of operations, where I had responsibility for the operations of the Oconee Nuclear and Keowee Hydro Stations. I have also served as engineering manager for the Catawba Nuclear Station and station manager for the McGuire Nuclear Station. Prior to my current role, I was Senior Vice President and Chief Fossil/Hydro Officer. I became the Senior Vice President of Generation and Transmission Strategy in 2021.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("COMMISSION") OR ANY OTHER STATE OR FEDERAL UTILITY COMMISSION?

A. Yes. I testified before this Commission in the following DEP Fuel Hearing Dockets: 2013 (No. E-2, Sub 1031), 2014 (No. E-2, Sub 1045), 2015 (No. E-2, Sub 1069), 2019 (No. E-2, Sub 1204), and 2020 (No. E-2, Sub 1250). I have also testified before this Commission in the following DEC Fuel Hearing Dockets: 2019 (No. E-7, Sub 1190) and 2020 (No. E-7, Sub 1228).

Q. MR. IMMEL, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steve Immel. My business address is 526 South Church Street, Charlotte, North Carolina, 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Carolinas, LLC and am the Vice President of Generation Transition Strategy.

Q. WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT OF GENERATION TRANSITION STRATEGY?

A. In this role, my team and I are responsible for identifying and integrating the various work streams associated with the orderly and executable transition of the generation fleet.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of Kentucky with a Bachelor of Science degree in Civil Engineering and a Masters of Business Administration from Queens College. My career began with Duke Energy in 1980 as an Associate Design Engineer. Since that time, I have held various roles of increasing responsibility in corporate facilities, investment recovery, supply chain, and operations areas, including the role of Hydro Manager; Station Manager at DEC’s Allen Steam Station and then Marshall Steam Station. I was named Vice President of Duke Energy Indiana’s Midwest Regulated Operations in 2012 and Vice President of

Outage and Project Services in 2014. In 2016, I was named Vice President of Carolinas Coal Generation for Duke Energy. I assumed my current role in 2020.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION OR ANY OTHER STATE OR FEDERAL UTILITY COMMISSIONS?

A. Yes. I testified before this Commission in DEC's general rate case in 2019 (Docket No. E-7, Sub 1214) and in DEC's fuel proceeding in 2021 (Docket No. E-7, Sub 1250). I also testified before the Public Service Commission of South Carolina in DEC's general rate case in 2018 (Docket No. 2018-319-E).

Q. MR. NOLAN, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Chris Nolan. My business address is 13225 Hagers Ferry Road, Huntersville, North Carolina, 28078.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Carolinas, LLC, and am the Vice President of New Nuclear Generation Strategy & Planning.

Q. WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT OF NEW NUCLEAR GENERATION STRATEGY & PLANNING?

A. I am responsible for the leadership and direction of the strategy and planning for new nuclear generation. This role is inclusive of policy, regulatory engagement, siting studies, and technology assessment.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of Maryland with a Bachelor of Science degree in mechanical engineering in 1987. I received a Master of Science degree in engineering management from the University of Maryland in 1998. I am a registered professional engineer in the Commonwealth of Virginia. I began my career as a qualified operator in the U.S. Navy's nuclear power program while employed at the Knolls Atomic Power Laboratory for General Electric Co. In this role, I successfully completed the U.S. Navy Nuclear Power School. Following that, I was a senior design engineer at Calvert Cliffs Nuclear Power Plant where I worked for nine years, before joining the U.S. Nuclear Regulatory Commission ("NRC"). I joined NRC in 1998, where I held roles of increasing responsibility in the Offices of Nuclear Reactor Regulation, Nuclear Security and Incident Response, and Enforcement. In my final assignment at NRC, I was chief of the New Reactors Environmental Projects Branch in the Office of Nuclear Reactor Regulation. I joined Duke Energy in 2006, and held positions of increasing responsibility including licensing manager in nuclear plant development, director of fleet safety assurance, and director of regulatory affairs. I was named Vice President of regulatory affairs, policy, and emergency preparedness in 2019. In June 2022, I was named Vice President of New Nuclear Generation Strategy & Planning.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION OR ANY OTHER STATE OR FEDERAL UTILITY COMMISSION?

A. No.

Q. MR. POMPEE, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Clift Pompee. My business address is 526 South Church Street, Charlotte, North Carolina, 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Carolinas, LLC, as the Managing Director of Generation Technology.

Q. WHAT ARE YOUR RESPONSIBILITIES AS THE MANAGING DIRECTOR OF GENERATION TECHNOLOGY?

A. I am responsible for providing leadership and direction for the review and awareness of new generation technologies, their domestic and global applications and functionality/performance and potential application for Duke Energy. I also support the development of generation portfolios of technologies that ensure affordability for our customers, resource adequacy, energy sufficiency, and system reliability to achieve Duke Energy's carbon reduction goals.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated with Honors from the University of Miami in 2001 with a Bachelor of Science degree in Mechanical Engineering with an Aerospace area of focus.

I started my career in August 2001, as an associate engineer providing steam turbine engineering support with Florida Power & Light ("FPL") in Juno Beach, Florida. I held multiple roles with FPL including plant engineering, operations, maintenance, monitoring & diagnostics and quality assurance. In 2008 I started working for Progress Energy in Crystal River, Florida as a nuclear assessor providing oversight of Nuclear Major Projects. In 2011, I started working as the supervisor of project controls scheduling and transitioned into that role in 2012 when Progress Energy and Duke Energy merged. I led the merger integration of the Nuclear Major Projects scheduling processes between the two legacy companies. In 2014, I joined the Fossil-Hydro ("FHO") organization as a gas turbine program manager, overseeing the GE 7F gas turbine program. In 2015, I became the manager of the Information and Analytics Group and worked on integrating analytics and data science into our FHO operations. This role evolved into becoming a product manager for digital transformation in 2018, where I used my background in operations, maintenance and engineering to oversee multiple digital products that the company was developing. In June 2021, I transitioned into my current role and have been responsible for evaluating emerging generation technologies that could support our decarbonization goals.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION OR ANY OTHER STATE OR FEDERAL UTILITY COMMISSION?

A. No.

Q. MR. REPKO, PLEASE SUMMARIZE THE PANEL'S TESTIMONY.

A. The purpose of the Panel's testimony in this proceeding is to provide an overview of the three long lead-time resources that the Companies[1] have included in certain of the portfolios presented in the Carolinas Carbon Plan ("Carbon Plan" or the "Plan") which the Companies jointly submitted to the Commission on May 16, 2022.

As explained in the Carbon Plan and in the Direct Testimony of Kendal C. Bowman, accomplishing energy transition and achievement of the 70% interim target will require decisive near-term procurement and development actions across various new supply-side resources, and the Companies have proposed aggressive near-term procurement of certain resources. However, certain of the supply-side resources that may potentially be needed to achieve North Carolina Session Law 2021-165's ("HB 951") targeted CO_2 reductions—offshore wind, small modular reactors ("SMRs"), and additional Pumped Storage Hydro—have substantially long lead-times and greater external dependencies. As a result, critical development work will be needed in the near-term to maintain optionality and the potential for in-service dates consistent with those contemplated in the Companies' modeling.

To be clear, the Companies are not requesting that the Commission "select" such resources under HB 951 at this time. Instead, initial development

[1] The individual resources will be developed in either DEC or DEP depending upon the resource. For simplicity of this testimony, references will be generically to the "Companies."

work is needed both to gather information to provide a more refined cost estimate to the Commission in future proceedings, as well as to allow the Companies to be positioned to implement such resources on a timeline consistent with the Companies' modeled portfolios. If the Companies do not undertake these development activities in the near-term for offshore wind, SMRs, and additional Pumped Storage Hydro (sometimes referred to collectively as the "long lead-time resources"), these resources will not be available on the timelines contemplated by the portfolios. Simply put, it is important to develop these long lead-time resources in order to preserve future options for our customers in North Carolina and South Carolina. And it is also important to note that all three long lead-time resources are likely to be needed to achieve carbon neutrality by 2050, and therefore, the development work performed in the near-term is likely to be needed as the Companies progress in their energy transition towards carbon neutrality. Importantly, this near-term development activity will allow the Companies to take additional critical steps toward refining the final cost estimates and then to present such information to the Commission in the biennial 2024 Carbon Plan update (or at an earlier date if needed).

In addition, our testimony will also provide further background on what makes these long lead-time resources unique and then, for each of the three resources, will provide further details regarding the resources, including identifying the scope and cost of the near-term development work that the Companies are proposing for Commission approval.

Finally, I note that pursuant to the Commission's July 29, 2022 *Order Scheduling Expert Witness Hearing, Requiring Filing of Testimony, and Establishing Discovery Guidelines* ("Scheduling Order") in this proceeding, certain legal issues related to the Companies' requests for relief concerning these long lead-time resources will be addressed in comments to be filed on September 9, 2022. While none of the members of this panel are attorneys and we do not intend to address those legal arguments, this testimony will make reference to certain legal conclusions that will be explained in more detail in the Companies' September 9, 2022 comments.

II. <u>OVERVIEW OF THE LONG LEAD-TIME RESOURCES</u>

Q. MR. REPKO, WHAT ARE THE THREE LONG LEAD-TIME TECHNOLOGIES FOR WHICH THE COMPANIES HAVE PROPOSED DEVELOPMENT WORK IN THE NEAR-TERM?

A. The Companies have requested approval of the near-term development actions (2022 through 2024) for: (1) Bad Creek II, a second powerhouse to be constructed at the Companies' existing Bad Creek I pumped hydro storage facility; (2) preparing an Early Site Permit ("ESP") that will be required to incorporate SMRs into the Companies' resource mix; and (3) preparing a Site Assessment Plan ("SAP") and early development of the Construction and Operation Plan ("COP") for an offshore wind generating resource off the coast of North Carolina.

Q. WOULD YOU PLEASE PROVIDE AN OVERVIEW OF THE DEVELOPMENT WORK NEEDED IN THE NEAR-TERM TO

PRESERVE THE POTENTIAL FOR THESE LONG LEAD-TIME RESOURCES TO BE SELECTED BY THE COMMISSION?

A. Yes. The near-term actions required to develop the resources necessary for energy transition, to replace coal generation and to meet load growth are included in each of the Carbon Plan portfolios set forth in Chapter 4 – Execution Plan of the Carbon Plan. "Near-term" development activities are those activities that the Companies have projected will be required from 2022 through 2024. The following summarizes the near-term development actions for Bad Creek II, SMRs, and offshore wind:

- Bad Creek II. The primary near-term development activities for Bad Creek II are as follows: (1) conduct a feasibility study; (2) develop an engineering, procurement and construction ("EPC") strategy; and (3) continue to develop the application to the Federal Energy Regulatory Commission ("FERC") to relicense the Bad Creek I facility to incorporate the Companies' operation of Bad Creek II.
- SMRs. The primary near-term development activities for SMRs are as follows: (1) begin work on an ESP for a to-be-determined site for one of the reactors; (2) perform a due diligence review to identify a nuclear technology for the SMRs that will ultimately be constructed; and (3) choose a company that will construct the new nuclear technology the Companies ultimately decide to have constructed.
- Offshore Wind. The primary near-term development activities for offshore wind are as follows: (1) secure an ownership interest in a lease for a Wind

Energy Area ("WEA") where the offshore wind resource will be located; (2) initiate and develop permitting activities, which will consist of (a) developing and submitting a SAP and beginning to engage with stakeholders; (b) developing a COP; and (c) initiating an interconnection study process; and (3) obtaining approval of a SAP from the Bureau of Ocean Energy Management ("BOEM").

Q. WHY IS IT IMPORTANT FOR THE COMPANIES TO PURSUE THIS DEVELOPMENT WORK?

A. The Companies believe that such development work is needed both to gather information to provide a more refined cost estimate to the Commission in the 2024 Carbon Plan update (or earlier as needed), as well as to be positioned to implement such resources on a timeline consistent with the carbon reduction targets established by HB 951. If the Companies do not undertake development activities in the near-term for these long lead-time resources, such resources will not be available on the timelines contemplated in the Companies' Carbon Plan modeling.

Q. WHY ARE THE COMPANIES PRESENTING THESE THREE RESOURCES TOGETHER IN THIS TESTIMONY?

A. All three of these resources require long lead-times to develop, construct, and incorporate into the Companies' resource mix than the other resources presented in the Carbon Plan filing and are, therefore, appropriately presented together for the Commission's consideration. Additionally, the Companies' near-term development plans for these resources generally focus on preliminary activities, which require more significant upfront costs to complete (as compared with other supply-side resources). Since energy transition will accomplish significant emissions reductions, as codified in HB 951, the Companies believe it is important to identify technologies that will efficiently deliver clean energy in the future, provide operational characteristics that differ from solar and batteries and to incorporate those technologies into the Companies' planning process. However, the long lead-times needed for these technologies require the Companies to begin development activities for these resources to serve our customers in North Carolina and South Carolina many years in advance.

Q. WHAT ARE THE COMPANIES REQUESTING WITH RESPECT TO THE LONG LEAD-TIME TECHNOLOGIES IN THE CARBON PLAN?

A. The specific requests for relief related to the development work associated with these long lead-time resources are set forth in the Companies' Petition for Approval of Carbon Plan and the Executive Summary (and are replicated in Exhibit 2 to the the testimony of Witness Bowman) and include the requests for Commission approval of the decision to incur expenditures related to the near-term development work for these resources as detailed by each witness below. As discussed above, legal issues related those requests for relief will be addressed in the Companies' comments to be filed on September 9, 2022. Our testimony focuses on factual issues related to these requests.

Q. ARE THE COMPANIES ASKING THE COMMISSION TO SELECT THESE LONG LEAD-TIME RESOURCES FOR INCLUSION IN THE CARBON PLAN AT THIS TIME?

A. No. The Companies' requests relate only to the initial development activities associated with pursuing the resources. Duke Energy acknowledges that it would be premature at this time to select these resources, but this development work will enable the Commission to fully consider the potential selection of these resources in future regulatory proceedings, such as the 2024 biennial Carbon Plan update, or future Carbon Plans depending on the status of development of the particular resource. This work will also allow South Carolina regulators to consider these resources as viable options.

Q. ARE THESE LONG LEAD-TIME RESOURCES LIKELY TO BE NECESSARY FOR THE COMPANIES TO MEET THE CARBON REDUCTION GOALS ESTABLISHED BY HB 951?

A. Yes. The Companies believe that it is likely that all three long lead-time resources will be needed to achieve HB 951's targets. While the technical details of the Companies' Carbon Plan modeling are outside the scope of this testimony, I will note that the Companies produced four separate portfolios in its initial Carbon Plan filing, and the Modeling and Near-Term Actions Panel testimony is presenting two additional portfolios. Bad Creek II is required under all portfolios, and SMRs are similarly required under all portfolios, though in some cases not until slightly later in time. While offshore wind is not selected in every portfolio for the interim 70% target, the Companies nevertheless believe that it is prudent to proceed with near-term development activities at this time to maintain it as an option given its technological maturity and ability to provide resource diversity.

Q. HOW IS THE REST OF THIS PANEL TESTIMONY ORGANIZED?

A. The following Duke Energy witnesses will now provide testimony on each of the three resources I have identified as follows:

1. Mr. Steve Immel will provide more detailed background regarding Bad Creek II;
2. Mr. Chris Nolan will provide more detailed background regarding SMRs;
3. Mr. Clift Pompee will provide more detailed background regarding the offshore wind resource.

III. <u>BAD CREEK PUMPED HYDRO EXPANSION</u>

Q. MR. IMMEL, BEFORE DISCUSSING THE PROPOSED BAD CREEK II PROJECT, WOULD YOU PLEASE PROVIDE SOME BACKGROUND ON BAD CREEK I?

A. Yes. Bad Creek I is located in Salem, South Carolina near the border of North Carolina. Bad Creek I came online in 1991 and provides 1,360 megawatts ("MW") of capacity. The plant stores and generates energy by moving water between two reservoirs at different elevations. During times of low electricity demand, surplus energy is used to pump water to an upper reservoir. The turbine acts as a pump, moving water back up to the upper reservoir from the lower reservoir, Lake Jocassee. During periods of high electricity demand, the stored water is released through turbines to provide energy to the grid. Bad Creek I works much like a conventional hydroelectric station, except the same water is used repeatedly. Bad Creek I has been included in prior IRPs since its commercial operation date in 1991 and has been a reliable asset for over 30 years.

Q. ARE ANY UPDATES PLANNED FOR BAD CREEK I?

A. Yes. Currently the four units at Bad Creek I are being upgraded by replacing and upgrading the pump-turbines, generator-motors, generator circuit breakers and making modifications to the electrical components. Once complete in 2023, the capacity of Bad Creek I will increase to approximately 1,700 MW. Upgrades have been completed on two units, and the remaining two units will be completed by the end of 2023.

Q. PLEASE DESCRIBE THE BENEFITS OF BAD CREEK I.

A. Bad Creek I provides valuable benefits to the grid, by storing energy from the grid when demand is low and generating when demand is high. Bad Creek I can store excess generation from low variable cost energy from the Companies' generation facilities at night and excess energy from solar during the day by pumping water to the upper reservoir and then releasing the water to meet customer demand in a cost-effective manner. In addition, Bad Creek I can provide capacity quickly if there is an issue on the grid. As non-dispatchable variable resources like solar and wind are added to the system, more storage will be needed to integrate these resources that do not produce energy coincident with peak demand and are highly variable because they depend largely on weather conditions that can be unpredictable. This growth in non-dispatchable generation was a primary driver for the current upgrade project at Bad Creek I to increase the net output of the station by approximately 320 MW.

Q. PLEASE PROVIDE DETAILS REGARDING BAD CREEK II.

A. Due to the unique geographic conditions at Bad Creek I, the Companies have identified the opportunity to essentially double the capacity of Bad Creek I through the addition of four new generating units totaling 1,700 MW—referred to as Bad Creek II. Bad Creek II would share the existing upper reservoir that is utilized by Bad Creek I. This would increase the total Bad Creek facility to over 3,330 MWs of capacity. Adding a second powerhouse will increase the capacity of the site, which supports the retirement of other generation assets and allows for more effective use of the reservoir.

As the system load profile and diversity of load and energy resources has changed over time, Bad Creek I has evolved into a daily cycling facility where units are started and stopped multiple times per day in either the generation or pump mode depending on the integration needs of the system. Bad Creek II will allow a more effective use of the existing reservoir. Expanding the site to build a second powerhouse would double the capacity of the station allowing for much more integration of low carbon resources and fully utilizing the upper reservoir.

Q. PLEASE DESCRIBE THE BENEFITS OF BAD CREEK II AS AN AVAILABLE RESOURCE.

A. Bad Creek II would be a valuable expansion of the Companies' pumped hydro fleet. DEC has successfully owned and operated Pumped Storage Hydro for almost 50 years. Currently, DEC operates two pumped hydro stations, Jocassee Station and Bad Creek I. Jocassee came online in 1973 and provides 780 MW of capacity. Pumped Storage Hydro is a proven long-duration technology which will enable more efficient use of other renewable and carbon-free resources. Bad Creek II is a unique opportunity for the Companies to add new long-duration, large-scale Pumped Storage Hydro without the need for a new reservoir. Any other additional Pumped Storage Hydro on our system would likely be substantially more costly, take longer to permit with more possible opposition and a longer time to construct. Additional Pumped Storage Hydro will allow the Companies to integrate more renewable and low-carbon generation to the grid and provide customers savings by storing excess generation during low demand and producing generation quickly and nimbly when demand is high.

Q. WHAT ARE THE NEAR-TERM DEVELOPMENT ACTIVITIES THAT THE COMPANIES ARE PROPOSING FOR BAD CREEK II?

A. Bad Creek I is currently in the relicensing phase at FERC. FERC relicensing provides an opportunity to include the additional powerhouse for Bad Creek II in the license application, expanding the capacity of the Bad Creek facilities starting with the receipt of the new license expected in 2027. In order to include

Bad Creek II in the FERC relicensing process, project development actions need to progress on a schedule that supports the information and data requirements of the FERC process.

The project development milestones that need to be completed to preserve the option of expansion as part of the FERC relicensing process are project design optimization, transmission impact determination and cost estimation with independent validation. Project design optimization includes geotechnical analysis, hydraulic design and model testing. These project optimization activities provide the basis of information that would be required during the relicensing process and needed to adequately scope the project needs for future solicitation for engineering, procurement and construction ("EPC") contractors to build the project. The Companies need to assess transmission impacts to initiate and construct transmission projects to support the new powerhouse at Bad Creek II. Finally, project design optimization and transmission impacts need to be estimated and independently validated to support the state and federal regulatory approvals required to construct Bad Creek II. The Companies retained an engineering firm to perform a pre-feasibility study, which was completed in 2019. The same firm is now performing a feasibility study, which will be completed in 3rd Quarter 2022. The Companies included the option of Bad Creek II in the FERC Pre-Application document for the relicensing of Bad Creek Project in February 2022 and entered into the Definitive Interconnection System Impact Study in June 2022. In addition, the Companies plan to hire a third-party construction company to review the Opinion of Probable Construction Cost. A complete list of the proposed near-term development activities for Bad Creek II, along with the relevant estimated cost for each activity, are set forth in Table 1 below:

Table 1: Bad Creek II Near-Term Development Activities

Activity Description	2022	2023	2024	Total
Pre-Feasibility/Feasibility Study	5,000,000			**5,000,000**
Support Project Optimization and Functional Design (Support EPC Tender)	1,000,000	3,000,000	3,000,000	**7,000,000**
Execute Phase 2 Geotech Exploration	1,500,000			**1,500,000**
Phase 2 Geotech Exploration Field Support and Analysis	1,500,000			**1,500,000**
Major PH Equipment Solicitation Support Activities				
Support Bid Spec Prep	1,000,000			**1,000,000**
Support OEM Bid Evaluation and Contract Negotiation	200,000	300,000		**500,000**
OEM Hydraulic Design and Model Testing		1,500,000	1,500,000	**3,000,000**
EPC Solicitation Support Activities				
HDR Support Contract Strategy and Planning		200,000	200,000	**400,000**
HDR Prepares Tech Specs / Exhibits in Support of Duke's EPC Solicitation			3,000,000	**3,000,000**
Large Generator Interconnect Study	255,000			**255,000**
EPC Independent Estimate Review	150,000	300,000		**450,000**
Project Mgmt, Project Engineering, Implementation Mgmt	150,000	250,000	350,000	**750,000**
Contingency	500,000	1,500,000	2,000,000	**4,000,000**
Licensing	800,000	3,200,000	3,500,000	**7,500,000**
Total	**12,055,000**	**10,250,000**	**13,550,000**	**35,855,000**

Q. WHAT IS THE PROJECTED CONSTRUCTION TIMELINE AND IN-SERVICE DATE FOR BAD CREEK II AND WHAT FACTORS DID THE COMPANY CONSIDER WHEN DEVELOPING THE IN-SERVICE DATE?

A. As discussed above, construction of Bad Creek II cannot be commenced without a FERC license. The Companies anticipate the construction of Bad Creek II to take approximately six years. Construction will begin in 2027, once the Companies receive the FERC license and regulatory approvals. This would put Bad Creek II's in-service date in 2033.

Q. WHAT IS THE BENEFIT TO CUSTOMERS OF PURSUING THE LICENSE FOR BAD CREEK II IN PARALLEL WITH NEEDED RELICENSING FOR BAD CREEK I?

A. Given the potential expansion opportunity, the Companies made the strategic decision to relicense the project using the Integrated Licensing Process ("ILP"). The ILP provides the most efficient and streamlined process of the relicensing process options available to a FERC licensee, which benefits customers. As an example, we successfully implemented the ILP for the downstream Keowee-Toxaway Hydroelectric Project resulting in new license issuance in 2016, prior to expiration of the project's original license. With receipt of a new license for Bad Creek expected in 2027, the current relicensing provides the shortest and best opportunity to explore project expansion. If the Company does not include Bad Creek II in the final FERC application, it will require the Companies to go through a duplicate process after receiving the license for the Bad Creek Project, which would take approximately five additional years from 2027 and cause stakeholders to go through a duplicative process. In addition, investment in Pumped Storage Hydro through Bad Creek II will provide the Company a higher probability of receiving a 50-year license for Bad Creek I and II versus a shorter duration license for Bad Creek I.

Q. WHY IS IT REASONABLE AND PRUDENT FOR THE COMPANIES TO ENGAGE IN INITIAL PROJECT DEVELOPMENT ACTIVITIES FOR BAD CREEK II?

A. Bad Creek II is identified as necessary in every portfolio assessed by the Companies, and no intervenor has presented alternative modeling that identifies a compliance plan without Bad Creek II. As such, the Companies believe it is likely that Bad Creek II will be needed as they retire coal plants and execute on energy transition and the Carbon Plan. Therefore, it is reasonable for the Companies to continue to pursue development activities in order to develop more refined cost estimates for future consideration by the Commission and to preserve the potential for Bad Creek II to be developed on a timeline consistent with that assumed in the Companies' modeling.

Q. HOW DO YOU RESPOND TO THE PUBLIC STAFF'S CONCERN THAT THE COMPANIES' ASSUMED TIMELINE FOR BAD CREEK II MAY NOT BE REALISTIC?

A. The Company has confidence that the new powerhouse can be in-service by 2033. A Pre-Feasibility Study has been completed and a Feasibility Study is underway. These studies outline the technical needs to construct the new powerhouse and include detailed timeline and cost estimates. Pursuing Bad Creek II within the relicensing of the current facility will allow the Company to receive the FERC license in the most efficient manner. Since Bad Creek II presents an unique opportunity to add additional Pumped Storage Hydro without the need of a new reservoir, a six-year construction timeframe is achievable.

IV. NEW NUCLEAR

Q. MR. NOLAN, WOULD YOU PLEASE DESCRIBE THE COMPANIES' EXISTING NUCLEAR FLEET, PERFORMANCE OF THE NUCLEAR FLEET, AND THE ROLE OF THE FLEET IN THE COMPANIES' OVERALL GENERATION MIX?

A. Duke Energy has the largest regulated nuclear fleet in the country, operating eleven large light-water reactors at six sites across the Carolinas. The nuclear fleet provides approximately 10,773 MW of capacity, which provides over 50% of the electricity used by Duke Energy's customers in the Carolinas, and 35% of Duke Energy's overall generation. This generation is approximately 83% of the zero-carbon energy produced by Duke Energy overall. The nuclear fleet avoided 50 million tons of carbon dioxide ("CO_2") emissions in 2021, which equates to keeping nearly 10 million cars off the road, and positively impacting the local communities.

The capacity factor is a ratio of the electrical energy produced compared to the maximum that could have been produced at continuous full power, demonstrating the long-standing reliability of the nuclear fleet. In 2021, the Companies' nuclear fleet operated with a combined capacity factor of 95.72%, establishing a new generation record, and marking the 23rd consecutive year that the fleet capacity factor has exceeded 90%. During the five-year period 2017 through 2021, Duke Energy's nuclear plants achieved a combined capacity factor of 94.83%, higher than the NERC five-year average capacity factor of similarly sized and types of U.S. reactors for the same five-year period. Duke Energy was the top-rated nuclear fleet in five of the last six years with respect to low-cost performance, and in 2021 produced electricity at the lowest cost per kWh among the eight largest U.S. nuclear fleets.

Q. PLEASE COMMENT GENERALLY ON THE COMPANIES' TRACK RECORD OF NUCLEAR OPERATIONS.

A. The Companies believe that, in considering the Companies' request to pursue development activities for SMRs, the Commission should consider Duke Energy's demonstrated exemplary performance and the industry-leading expertise that it can bring to bear in deploying new nuclear. While SMRs would obviously be a new technology to the Carolinas, the Companies are confident that their deep and established internal expertise on nuclear operations would provide a strong foundation on which to build.

Q. WHAT ARE THE BENEFITS OF NUCLEAR GENERATION?

A. Duke Energy's nuclear fleet of 11 reactors has been producing power safely and reliably for our Carolinas customers for over 50 years, since the H.B. Robinson Nuclear Plant started commercial operation in 1971. Since then, the Duke Energy fleet has generated more than 3.161 billion MWh of electricity in the Carolinas. Our nuclear power plants can provide zero carbon generation 24 hours a day, seven days a week. This baseload generation is essential to providing reliable energy, especially when paired with an ever-increasing generation mix of variable renewable power. Nuclear power can help meet the load demands of our customers when renewable generation is not available or significantly reduced. The approximately 10,773 MW generated by Duke's fleet of 11 reactors provided power to over 8 million homes in the Carolinas, supporting the local communities with well-paying jobs and resulting in more than $251.4 million in taxes to local and state government in 2021.

Q. PLEASE BRIEFLY DISCUSS YOUR PLANS TO PURSUE SUBSEQUENT LICENSE RENEWAL FOR THE EXISTING NUCLEAR.

A. The Companies have announced plans to pursue subsequent license renewal ("SLR") for all eleven operating nuclear units. Pursuing SLR for the fleet will extend the operating life of these investments for an additional 20 years (80 years total). The licenses of the nuclear fleet are currently scheduled to expire beginning in 2030, with the last unit ending operations in 2046. With SLR approval, the retirements for the operating fleet will shift to 2050–2066. Continued operation of the Duke Energy nuclear fleet is essential to ensure a reliable transition to achieve net-zero generation. All of the Companies' planning models rely on SLR of the existing nuclear units to achieve our net-zero carbon emission goals, and no party to this proceeding has offered an alternative compliance pathway that does not rely on these SLRs. Therefore, the Companies believe that the Commission should approve the Companies' continued pursuit of SLRs for the existing nuclear fleet.

Q. HOW ARE NEW NUCLEAR REACTORS DIFFERENT FROM EXISTING NUCLEAR FACILITIES?

A. New nuclear reactor technology has evolved from nuclear plant designs that have run safely and reliably for many years. The anticipated benefits from new nuclear technologies are expected to exceed those that are provided by the existing nuclear fleet. The new technology has improved on past designs and provides additional safety features beyond those that already exist in plants that are safely operating today. New nuclear includes SMRs, advanced reactors ("AR") and microreactors, as described in Table L-2 of the Carbon Plan. SMRs are water-cooled reactors and ARs are non-water-cooled (e.g., molten salt, liquid metal, or high-temperature gas). The modular design of these new reactors allows for more off-site construction and decreases production timelines. Designs have become smaller, meaning units require less capital investment and are more flexible, allowing for greater ability to match power output to system loads and to more accurately meet growth in demand. The ability to load follow allows new nuclear to integrate well with variable renewables, and higher operating temperatures for some ARs allows for other uses such as thermal storage, hydrogen production, and industrial applications. In addition, the new generation of nuclear plants include inherent safety features, such as passive cooling systems and lower water capacity requirements that allow facilities to shut down and self-cool through natural circulation. This means that the system can turn off and cool indefinitely with no operator intervention, and can operate in much smaller emergency planning zones that allow for location in more populated areas.

SMRs are used in all portfolios in the Carbon Plan modeling to achieve carbon neutrality by 2050. Since they are most similar to today's operating reactors, SMR technology will be most feasible before 2034. ARs are modeled in the plan beginning in 2038.

Q. HOW ARE SMRs DIFFERENT FROM ARs?

A. SMRs use water for cooling, just like all the commercial operating nuclear plants in the U.S. today. Therefore, it is a well-known and proven technology, with a more readily available supply chain. SMRs have a less challenging licensing path because their design is based on existing large light-water designs. ARs use liquid metal (e.g., sodium), molten salts (e.g., chlorides, fluorides), or high-temperature gas (e.g., helium) for cooling. ARs provide flexible operations that can support hydrogen production, thermal storage, and integration with variable renewable energy. Although there are a few ARs operating successfully today internationally, there are no operating AR generation facilities in the U.S. Additionally, leading SMRs use fuel much like that in current operating facilities, whereas many of the leading ARs use a higher-enriched fuel, called high assay low enriched uranium ("HALEU"). Although there are efforts underway to develop U.S.-based HALEU enrichment facilities, there are currently no enrichment facilities in the U.S. producing HALEU, which provides additional schedule risk for any design using HALEU.

Q. WHAT ARE THE OPPORTUNITIES FOR FEDERAL GOVERNMENT FUNDING FOR ADVANCED NUCLEAR TECHNOLOGY PROJECTS?

A. The Department of Energy ("DOE") created the Advanced Reactor Demonstration Program ("ARDP") in 2020 to help domestic private industry demonstrate advanced nuclear reactors in the United States. The awards are cost-shared partnerships with industry that will deliver two first-of-a-kind ARs to be licensed for commercial operations. X-energy and TerraPower/GEH were the chosen award winners for the Xe-100 and Natrium reactors, respectively. Duke Energy is a partner in the Natrium project, providing advisory and in-kind consulting service to TerraPower. In 2021, the U.S. Congress passed the Infrastructure Investment and Jobs Act that appropriated $1.23B for each awardee, officially funding the ARDP selected awards for the rest of the seven-year term.

Additionally, DOE's Loan Program Office has $10.9 billion in loan guarantee authority for nuclear projects—including $2 billion specifically for front-end projects. The loan guarantee program helps eliminate gaps in commercial financing for energy projects in the United States that utilize innovative technology to reduce, avoid, or sequester greenhouse gas emissions.

Q. PLEASE DISCUSS THE CURRENT STATE OF NEW NUCLEAR TECHNOLOGY.

A. There are currently about five to ten new nuclear reactor technologies that can be considered as viable candidates based on their design and licensing status in the U.S. Of the leading technologies, four are scheduled to be built on five different projects and are expected to be operational in the next decade. Below are the five projects.

GE Hitachi BWRX-300 (SMR)

Ontario Power Generation is building a BWRX-300 (300 MW) at its Darlington Site in Clarington, Ontario. It is scheduled to be operational in 2029.

Tennessee Valley Authority has signed an agreement to support preliminary licensing for the potential deployment of a BWRX-300 (300 MW) at its Clinch River Site in Oak Ridge, Tennessee. It is planned to be online in the early 2030s.

NuScale VOYGR (SMR)

NuScale Power has an agreement to build a VOYGR-6 plant (6 x 77 MW = 462 MW) for Utah Associated Municipal Power Systems at the Idaho National Labs. It is scheduled to be operational by 2029. DOE is providing up to $1.4B in a cost-sharing arrangement as part of the zero carbon Power Project.

TerraPower/GEH Natrium (AR)

TerraPower is building a Natrium plant (345 MW) for PacifiCorp in Kemmerer, Wyoming, near the site of one of its retiring coal plants. It is scheduled to be operational in 2028. DOE has funded approximately $1.31B ($0.08B + $1.23B) as a cost-sharing arrangement as part of ARDP.

X-energy Xe-100 (AR)

X-energy and Energy Northwest/Grant County Public Utility are building an Xe-100 plant (4 x 80 MW = 320 MW) in the state of Washington. It is scheduled to be operational in 2028. DOE funded approximately $1.3B as a cost-sharing arrangement as part of ARDP.

Q. HAVE THE COMPANIES SELECTED A PREFERRED NEW NUCLEAR TECHNOLOGY AT THIS TIME?

A. No. The Companies are currently performing a thorough review of potential SMRs and ARs to determine the most viable, cost-effective new nuclear technology for our customers. An SMR was used in the modelling as the first units to be built due to similarity with existing reactor technology and corresponding licensing advantages. Given the rapid pace of development for both SMRs and ARs, the Companies believe it is prudent to move forward with site selection and an ESP, which is technology neutral, and then select a technology, either SMR or AR, at the appropriate development timeline. An ESP application provides the Companies an opportunity to obtain NRC approval of one or more sites for a new nuclear power plant, independent of a specific nuclear plant design or an application to build. The ESP provides for NRC approval of the siting of one or more reactor technologies (i.e., bounded by the plant parameter envelope in the ESP) at a specific site for up to 20 years, with the option to renew for an additional 20 years. Such a sequence will ensure the Companies are positioned to select the best, most cost-effective technology selection. The ESP results in a final agency position available for referencing in subsequent applications for either a construction permit or a combined construction and operating license ("COL").

Q. WHAT ARE THE NEAR-TERM DEVELOPMENT ACTIVITIES FOR NEW NUCLEAR?

A. The near-term development activities for new nuclear are detailed in Table 4-7 of the Carbon Plan and are provided below.

Near-Term Actions (2022-2024)

2022-2023

- Organize nuclear development staff for new nuclear builds
- Perform new nuclear alternative siting study
- Perform new nuclear technology selection
- Begin new nuclear ESP development
- Choose the advanced nuclear technology/company to build the first plant(s)

2024

- Develop new nuclear construction and operating license application

Performing these development activities is essential to preserve the potential to allow the initial new nuclear SMR unit in-service date of mid-2032 to be met. To achieve a mid-2032 in-service date, developing an ESP must be started as soon as possible. An ESP takes approximately two years to develop and submit, and an additional two years for NRC review and approval. The estimated timeline for development of a SMR to be operational by mid-2032, as shown in Table L-3 of the Carbon Plan, has the ESP being submitted to the NRC in mid-2024.

Q. WHAT IS THE PROJECTED COST OF THE NEAR-TERM DEVELOPMENT ACTIVITIES FOR NEW NUCLEAR?

A. Table 2 below shows the cost estimate for the near-term development activities for new nuclear.

Table 2: New Nuclear Near-Term Development Activities

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

Q. WHAT IS THE PLANNED CONSTRUCTION TIMELINE/IN-SERVICE DATE FOR NEW NUCLEAR?

A. The planned construction timeline and in-service date is provided in Appendix L "Nuclear" of the Carbon Plan, in Figure L-3: Estimated Timeline for Development of a SMR – To be Operational by Mid-2032. Key milestones to meet the mid-2032 timeline include:

- Submit an ESP to the NRC in late 2024
- Submit a COL application to the NRC by July 1, 2026
- Construction period July 1, 2029 to July 1, 2032
- Begin fuel load and low power operations 3rd Quarter 2032

Q. PLEASE DISCUSS WHY NEW NUCLEAR IS IMPORTANT TO THE COMPANIES' ABILITY TO REACH THE CARBON REDUCTION GOALS SET BY HB 951.

A. New nuclear provides firm, dispatchable, zero carbon energy to the system that can be increased or decreased due to the greater flexibility of new nuclear compared to traditional nuclear. Flexible, zero carbon energy is extremely important for system reliability and the Companies' overall decarbonization effort. As other technologies continue to develop, there may be additional options for providing firm, dispatchable, zero carbon energy to the system, but in the near-term, new nuclear appears to be one of the only options for this system need. Additionally, ARs have even greater use to the system due to their extremely flexible output. The pairing of thermal storage or other mechanisms to shift power by providing a higher peak output when required or a lower output to the system during periods of overproduction of renewable energy is extremely valuable to the overall modeling and expected system configuration in the 2030s and 2040s.

Q. WHY IS IT REASONABLE AND PRUDENT FOR THE COMPANIES TO ENGAGE IN INITIAL PROJECT DEVELOPMENT ACTIVITIES FOR NEW NUCLEAR?

A. As discussed above, nuclear is a reliable asset that contributes to the long-term, low and stable electric rates realized by our customers. Nuclear is identified as being necessary to achieve the interim CO_2 reduction goals in the four Portfolios presented in the Carbon Plan and the two supplemental Portfolios presented by the Modeling and Near-Term Actions Panel direct testimony. All six portfolios include the addition of new nuclear ranging from 7.6 GW to 8.0 GW by 2050.

The Companies are achieving early carbon reductions through the retirement of coal replaced with increased generation from variable renewables like wind and solar supported by dispatchable natural gas resources. Further reductions in carbon emissions will require a combination of variable resources, storage, and additional zero carbon dispatchable generation to reliably meet the energy demand. The Companies have used the phrase "zero-emitting load following resource" to categorize this generation resource type. New nuclear is based upon reliable technologies that can serve this need. New nuclear meets the intent of a low-cost option when paired with variable renewables and storage to reliably provide carbon reductions of 70% and beyond. New nuclear that integrates thermal storage provides even more benefit as discussed above.

Q. HOW DO YOU RESPOND TO THE COMMENTS OF THE PUBLIC STAFF THAT THE PACE AND TIMING OF THE PROPOSED SMR ADDITIONS ARE "VERY AGGRESSIVE AND REPRESENT SIGNIFICANT PORTFOLIO RISK" AND THAT THE TIMELINES ARE "SPECULATIVE"?

A. The timeline to have the first new nuclear plant in operation in mid-2032 is achievable with the development actions provided in the Carbon Plan filing, and the risk mitigation measures the Companies are taking as noted below. The Companies are taking a number of prudent steps to minimize the first-of-a-kind risks associated with new nuclear deployment. First, the pursuit of an ESP will allow the resolution of site safety and environmental issues before a technology is selected or a decision to build has been made. The ESP process will allow additional time to select a technology, ensuring selection of the most prudent, cost-effective technology. As discussed above, there are four different technologies being pursued by five different projects which are all expected to be operational by 2029. With four different reactor technologies expected to be demonstrated by the end of this decade, Duke Energy believes that it may be prudent to seek to be a second mover to avoid first-of-a-kind costs but is mindful that supply chain capacity is a risk factor that can impact deployment timing and may alter that consideration.

To ensure the Companies are well-positioned to evaluate new nuclear technologies, the Companies are participating in the utility advisory boards for numerous technologies in order to stay current with developing technologies as industry-leading designs emerge. For example, we are participating with TerraPower and others in the development of the Natrium design funded by the DOE's ARDP. This AR design will have integrated molten salt storage that will integrate well with solar, maximizing the benefit of both technologies. The Companies are pursuing a technology assessment process that will compare risks in a formalized approach and provide a measured approach with regard to deployment timing. The Companies will continue to evaluate new information regarding the assessment of risks for technology, cost, and schedule for energy transition. The near-term activities described in the Carolinas Carbon Plan are targeted at this approach.

The proposed near-term actions support various deployment schedules with different types of new nuclear technology. An early deployment schedule will favor light-water SMR technologies, because the technology utilized in them is similar to the plants that we operate today. A later deployment date would allow the experience gained from the DOE's ARDP to be more qualitatively assessed, opening the possibility for deployment of AR designs that include enhancements in their operational characteristics, fuel designs and safety systems. In addition, ARs have improved load-following characteristics and/or integrated thermal storage that allow for better integration with variable renewables like wind and solar that would provide economic benefits to the customer. As a result, the Companies will continue to assess technology as new information becomes available.

The Companies' proposed near-term actions enable a focus on light-water SMRs early, allowing for a transition to ARs after they have demonstrated performance. This approach allows the Company to meet the objectives of HB 951 in meeting the 70% reduction early, while allowing for the benefits of ARs to contribute to achieving net-zero by 2050.

Q. HOW DO YOU RESPOND TO THE COMMENTS OF INTERVENORS THAT NEW NUCLEAR TECHNOLOGY IS UNPROVEN?

A. SMRs being developed today rely on a very proven technology, as they are based on the same technology used inas all of the commercial nuclear plants in operation in the U.S. today. Light-water SMRs are either boiling water reactors or pressurized water reactors, using water as their cooling source. The large light-water reactors ("LLWR") operating in the U.S. today have been operating reliably and safely for more than 50 years. The SMRs have used lessons learned from all of these years to improve on the technology that is being used in today's commercial fleet. As an example, the GEH BWRX-300 SMR is based on the GEH Economic Simplified Boiling Water Reactor LLWR that has already been licensed by the NRC as an improved design over the LLWRs in operation today.

ARs being developed today are also based on proven technologies. Test and research reactors in the U.S. have used liquid metal, molten salts, or high temperature gas as cooling since the 1960s. For liquid metal-cooled reactors, the Experimental Breeder Reactor 2 ("EBR-2") operated for 30 years (1964-1994) in Idaho, and the Fast Flux Test Facility ran from 1982-1993 in the state of Washington, both using liquid sodium as a cooling source. The Molten Salt Reactor Experiment that ran at Oak Ridge National Lab in the 1960s is an example of a molten salt-cooled reactor. For HTGR, the Peach Bottom Unit 1 nuclear station in Pennsylvania ran from 1966-1974, and the Fort St. Vrain nuclear generating plant in Colorado ran successfully from 1979-1989 as a power generation facility. The new ARs being developed have also used lessons learned from these test and research reactors and improved the design, providing a viable alternative to LLWRs. In addition, there are ARs currently in operation today in a number of foreign countries, including the United Kingdom (HTGRs), China (HTGR), and Russia (liquid sodium-cooled).

Q. HOW DO YOU RESPOND TO COMMENTS THAT NEW NUCLEAR TECHNOLOGY PRESENTS SIGNIFICANT ENVIRONMENTAL RISKS AND SAFETY CONCERNS?

A. The Companies fundamentally do not agree that new nuclear presents significant environmental risks and safety concerns. The new technology has improved on past designs and has many inherent safety features that make them even safer than those plants operating today. As discussed earlier, when comparing the benefits of new nuclear designs over existing operating plants, the improved safety features allow the new reactors to be considered "walk-away safe," automatically shutting down and self-cooling for an extended period of time, all with no operator actions required.

In addition, environmental impacts, site safety, and external hazards are important factors in siting new nuclear plants. The NRC considers the issuance of a license or an ESP to be a major federal action requiring the issuance of an Environmental Impact Statement under the requirements of the U.S. National Environmental Policy Act. To obtain an operating license from the NRC, the process for new nuclear plants requires an extensive environmental evaluation, a final safety analysis report, emergency planning and physical security information. The environmental and safety requirements for new SMRs and ARs are currently the same as for those required of large light-water cooled reactors. However, the NRC is developing a new rulemaking[2] that will

[2] *See* 85 Fed. Reg. 71,002 (Nov. 6, 2020) (to be codified at 10 C.F.R. pt. 53).

streamline the licensing of new nuclear technologies due to the fact that the improved inherent safety features of SMRs and ARs make some of the existing regulations no longer necessary. The NRC is targeting the new rule issuance in July 2025. These regulatory-required processes ensure that all environmental and safety issues are acceptable for a new SMR or AR to be granted an operating license.

Q. HOW DO YOU RESPOND TO THE ASSERTION THAT DUKE ENERGY SKEWS COST ESTIMATES IN FAVOR OF NEW NUCLEAR AND AGAINST SOLAR, STORAGE, AND WIND?

A. The Companies used reasonable cost estimates for new nuclear based on the most updated information that was available at the time the estimate was produced. These high-level cost estimates are primarily based on information provided by the reactor technology vendors and industry operating experience. The Companies acknowledge that the cost estimates for new nuclear will need to be refined over time, just as is the case for all resources being considered for energy transition and included in the Carbon Plan. But, as discussed above, given its operating characteristics compared to other resources, new nuclear will be an essential part of the path to carbon neutrality. As such, it is reasonable and prudent for the Companies to pursue development activities in the near-term, in part, to produce more refined cost estimates that can be considered by the Commission in the future. As some of the new advanced nuclear projects scheduled to be completed this decade move further along in the construction cycle, more refined cost estimates can be determined. The Company is taking prudent steps to minimize first-of-a-kind risks, such as the early resolution of siting issues, participation in the utility advisory boards for numerous technologies, participation in the DOEs ARDP, and a measured approach with regards to deployment timing. The Company will continue to evaluate new information regarding the assessment of risks for technology, cost, and schedule.

V. OFFSHORE WIND

Q. MR. POMPEE, PLEASE DISCUSS THE CURRENT STATE OF OFFSHORE WIND GENERATION IN THE U.S.

A. Offshore wind technology is relatively new in the U.S., but the deployment of the technology has a 25-year track record globally. In the U.S., there are currently seven offshore wind turbines in operation (five in Block Island, owned by Ørsted and two off the coast of Virginia owned and operated by Dominion Energy). However, the U.S. offshore wind market is burgeoning, with over 30 GW of projects with leases in place to achieve state carbon reduction and economic development policy goals. In the last several years, the U.S. offshore wind market has seen an increasing number of executed leases and project development activity, mostly occurring in the Northeast.

Offshore wind on the Atlantic Outer Continental Shelf ("OCS") has advantages because of the relatively shallow water depths that allow for fixed-bottom installation technologies compared to the Pacific OCS, where floating technology required. Fixed-bottom foundation technologies are the most mature offshore wind foundation technology, with roughly 75% utilizing monopile foundations and the remainder utilizing jacketed foundations, as is common in oil and gas exploration. Depending on the site conditions and the water depth, monopile or jacketed foundations are the likely foundation technologies to be deployed off the coast of North Carolina. The leasing and development of offshore wind parcels has been steadily moving south, with three leases in North Carolina executed in the last five years. Two of these leases were executed in July 2022 off the coast of Cape Fear, North Carolina in the Carolina Long Bay Area.

Q. DESCRIBE THE THREE SITING POSSIBILITIES FOR OFFSHORE WIND IN THE CAROLINAS.

A. Offshore wind in the Carolinas currently consists of three siting possibilities (i.e., only three WEAs). The Kitty Hawk parcel ("Kitty Hawk") (a 200-square-mile area (~127,000 acres), approximately 27 miles from Corolla, N.C. on the Outer Banks) was auctioned in 2017 and acquired by Avangrid Renewables ("Avangrid"). The second area, known as Carolina Long Bay ("Carolina Long Bay") a 170-square mile area (~110,000 acres), is composed of two wind leases of roughly 55,000 acres each located approximately 20 miles from Cape Fear, N.C., and was auctioned in May 2022. TotalEnergies Renewables USA, LLC and Duke Energy Renewables Wind, LLC each acquired one of the leases. The energy produced by projects in Carolina Long Bay and Kitty Hawk could produce approximately 4,800 MW. All the three parcels would require cabling from the wind farm to onshore, with Kitty Hawk having a significantly longer subsea cabling requirement due to its location near the North Carolina/Virginia border. For all parcels, once the cabling comes onshore, network upgrades and new transmission infrastructure will have to be built in order to connect to the Companies' transmission system.

Q. WHAT ARE THE BENEFITS OF OFFSHORE WIND?

A. The benefits of offshore wind include carbon emissions reduction, fuel cost savings, and increased renewable resource diversity in regions with high penetration of solar energy. With a minimum of 12 GW of total system solar identified to achieve the interim emissions reduction targets in the Carbon Plan portfolios, offshore wind would provide important resource diversity to complement solar variability.

The energy profile of offshore wind complements the energy profile of solar for both daily and seasonal generation. For example, as more solar is added, the summer peak planning hour shifts to the early evening as solar generation decreases and offshore winds increase. Offshore wind especially complements solar in the winter. The peak planning hour for the year has shifted from the summer afternoon to the early winter morning. This is primarily due to the increasing amounts of solar added to the system. Offshore winds highest seasonal generation is in the winter mornings, when solar generation is not available.

The relatively high-capacity factors and lower intermittency for offshore wind compares favorably to other low carbon resources. The location of offshore wind turbines, more than 20 miles from shore, allows for very large wind farms, larger wind turbines and taller towers. This has the net result of increasing the capacity and capacity factor of offshore wind, resulting in site outputs typically measured in gigawatts. Offshore wind farm capacities are typically orders of magnitude larger than onshore wind or solar farms, without the associated land use issues.

Q. WHAT IS THE PROCESS FOR DEVELOPMENT OF OFFSHORE WIND SITES?

A. The process of leasing offshore wind is managed by the BOEM, part of the Department of the Interior. Once a lease has been executed, it takes approximately 8 – 10 years from leasing a WEA to commercial operation. Dominion Energy acquired a commercial lease in 2013, and nearly a decade later, in August 2022, received approval from the Virginia State Corporation Commission to move forward with a 2.6 GW Coastal Virginia Offshore Wind project by 2026. Dominion Energy is still waiting approval of its COP to move forward with this project.

Figure 1: BOEM Offshore Wind Development Process

As stated in the Carolinas Carbon Plan and by intervenors, the development of an offshore wind project can take up to 10 years. The "Site Assessment" shown in Figure 1 above, includes the Site Assessment work and the COP and approval. The development timeline provided by BOEM also illustrates the maximum expected time. The "Site Assessment" shown above represents the maximum amount of time BOEM allows for a lessee to perform this step and could be completed in three years versus the five years illustrated if sufficient pre-development approvals are received. When developing the Plan, Duke Energy took into consideration this timeline as well as the work required to achieve a 2030 commercial operation date, at the soonest. As a result of this schedule, it is prudent and reasonable to begin the development of offshore wind in the near-term so that the Companies can gather a more refined cost estimate for Commission consideration in the future and to preserve the potential for offshore wind to be available on a schedule consistent with the Companies' modeled assumptions.

Q. PLEASE DISCUSS WHY OFFSHORE WIND IS LIKELY TO BE IMPORTANT TO THE COMPANIES' ABILITY TO REACH THE CARBON REDUCTION GOALS SET BY HB 951.

A. Although offshore wind is only selected in certain of the Companies' Portfolios, the Companies believe that it is prudent and reasonable to preserve the option to diversify the Plan with offshore wind and many intervenors appear to agree. Offshore wind could potentially alleviate the reliance on specific technologies, potential gas pipelines, and the ability to procure, construct and operate an unprecedented amount of solar in the Carolinas.

Q. DID THE COMPANIES' MODELING IN THE CARBON PLAN ASSUME OFFSHORE WIND IN A PARTICULAR WEA?

A. No. The Companies' Carbon Plan modeling assumed a generic offshore wind resource off the coast of North Carolina but did not assume a particular WEA, because it is not necessary for modeling purposes to assume a particular WEA.

Q. PLEASE DESCRIBE WHY SELECTION OF A WEA WILL BE NECESSARY TO BEGIN NEAR-TERM DEVELOPMENT ACTIVITIES.

A. Most of the near-term development activities required are site-specific. That is, the Companies must have obtained a specific WEA to commence with the site assessment activities.

Q. PLEASE COMMENT GENERALLY ON THE AVAILABLE OPTIONS FOR WEAS.

A. As discussed above, there are only three WEAs available at this time. Importantly, N.C. Gen. Stat. § 62-110.9(2) specifies that "[a]ny new generation facilities or other resources selected by the Commission…shall be owned and recovered on a cost of service basis by the applicable electric public utility." The legal issues related to this issue will be addressed as directed by the Commission in comments to be filed by the Companies on September 9, 2022. However, for purposes of this testimony, counsel for the Companies have informed us that the Companies are legally required to own any offshore wind generation selected by the Commission as part of the Carbon Plan.

Given that background, the Carolina Long Bay lease obtained by Duke Energy Renewables Wind, LLC appears at this time to be the only WEA definitely available for further development by the Companies. The comments submitted by Avangrid and TotalEnergies do not indicate a clear desire to sell their WEAs to the Companies (or to develop a wind generation facility on their WEA and then sell the entire asset to the Companies). Therefore, absent direct expressions of interest, there is essentially only one option for pursuing development activities for offshore wind at this time.

Q IS DUKE ENERGY WILLING TO CONSIDER POTENTIAL ARRANGEMENTS WITH AVANGRID AND TOTALENERGIES IN WHICH DUKE ENERGY PURCHASES THE WEAS ?

A. Yes. The Companies remain open to opportunities for ownership of cost-effective offshore wind WEAs to develop on behalf of our customers.

Q ASSUMING THAT AVANGRID AND TOTALENERGIES DO NOT EXPRESS A CLEAR DESIRE TO SELL THEIR RESPECTIVE WEAS, WHAT WOULD BE THE NEXT STEP WITH RESPECT TO CAROLINA LONG BAY?

A. Assuming the Commission agreed that it is prudent and reasonable to pursue further offshore wind development activities, the Companies would seek affiliate approval from the Commission to transfer the Carolina Long Bay lease from Duke Energy Renewables Wind, LLC. In parallel with such transfer, the Companies would proceed with development activities on the Carolina Long Bay lease to further the opportunity to develop an offshore wind project.

Q. WHAT ARE THE NEAR-TERM ACTIVITIES AND COSTS ASSOCIATED WITH THE DEVELOPMENT ACTIVITIES FOR OFFSHORE WIND?

A. As discussed above, the key near-term development activity is obtaining a WEA. As such, these costs include the cost of acquiring the Carolina Long Bay WEA lease from the Companies' affiliate (including the requisite approval from the Commission). The additional costs include the annual rent for the lease to BOEM in the amount of $3 per acre per year.

The near-term activities required to continue developing the Carolina Long Bay lease will help ensure that the area is able to be further developed. The near-term activities being planned include the development of a SAP, site survey activities and preliminary engineering. The near-term costs presented do not include the system upgrades required to ensure the transmission system is ready to support the injection of offshore wind (depending on the portfolio). These near-term activities include:

a. Development of the SAP (6-12 months) for approval by BOEM within 12 months of acquiring a lease (June 2023). The SAP includes a list of site characterization activities that are required to be performed to gain a more detailed understanding of the lease area and how to plan, engineer and develop the WEA. SAP approval is required in order to deploy a meteorological buoy to collect wave, wind, current and other data that will help inform design of foundations, towers and wind turbine components as part of the COP.

b. Develop a Survey Plan as part of the SAP (2023-24) to include the following surveys:

    i. Geophysical surveys

    ii. Geotechnical surveys

    iii. Baseline biological surveys

    iv. Met-ocean data collection (deploy floating LiDaR and buoys). BOEM must approve the SAP before the lessee can deploy meteorological buoys for data collection.

c. Begin development of the COP including baseline survey activities, engineering, design and fabrication reports for proposed offshore wind project as part of the federal, state and local permitting activities. The COP is required to be approved by BOEM before any construction activities can be performed on the OCS. Development of the COP can take as few as 3 years and no more than 5 years once the SAP is approved by BOEM. All federal, state and local approvals coincide with submission of the COP under the National Environmental Policy Act.

d. Begin development work to support the transmission interconnection facilities from the landing site to the Point of Injection (expected to be the New Bern substation). This work would include evaluation of land needed, preliminary engineering for routing path, feasibility study of potential beach landing, creating engineering standards, developing and executing stakeholder engagement plan. Additionally, the work would require preliminary permitting requirements for the eventual construction of transmission from the landing site to New Bern; approximately 40 miles.

The costs for the near-term development activities are shown in Table 3 below:

Table 3: Offshore Wind Near-Term Development Activities

Activity Description	2022	2023	2024	Total
Lease	$155,000,000	$200,000	$200,000	**$155,400,000**
Development Expenses	$2,000,000	$20,000,000	$40,000,000	**$62,000,000**
Transmission from landing site to point of injection	$5,000,000	$10,000,000	$85,000,000	**$100,000,000**
Construction	$0	$0	$0	**$0**
Total:	$162,000,000	$30,200,000	$125,200,000	**$317,400,000**

A mix of internal project development and external consultants will be used, including project management, engineering, environmental, stakeholder engagement and community outreach resources.

Q. WITH THIS BACKGROUND, WHAT DO YOU ANTICIPATE TO BE THE TIMELINE FOR THE FURTHER DEVELOPMENT OF OFFSHORE WIND RESOURCES?

A. It is our understanding that Duke Energy Renewables Wind, LLC is currently working on the SAP, which is targeted for completion by mid-2023 based on the timeline established by BOEM. The SAP includes, among other elements, the development of a Survey Plan for deployment of a meteorological buoy and floating lidar device to collect important data for the engineering and design of an offshore wind project. Upon receiving BOEM approval for the SAP as well as other applicable permits, the lessee is allowed to deploy meteorological buoys and floating LIDAR technology. Assuming site characterization and subsequent engineering starts in 2023, development and submittal of the COP could be completed by mid-2025, and approvals by BOEM in 1-2 years. To achieve year-end 2030 commercial operation, equipment procurements would most likely have to be initiated prior to getting the final COP and permitting approvals. This could present significant financial risk for the Companies and its customers. Timelines for commercial operation beyond 2030 would reduce the financial risk as well as allow for permitting and supply chain efficiencies and technology advancements to be realized.

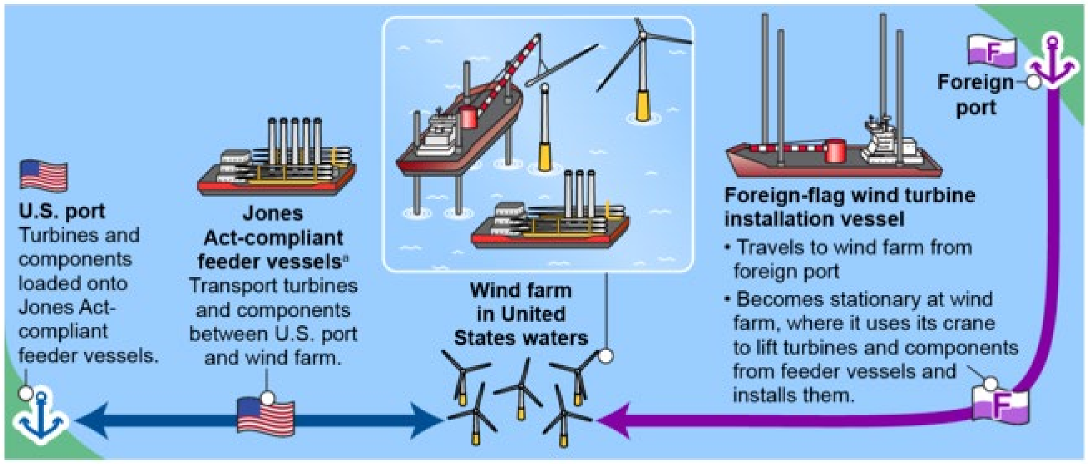
Q. THE PUBLIC STAFF RAISED A CONCERN WITH THE COMPANIES' ABILITY TO CONSTRUCT OFFSHORE WIND DUE TO THE JONES ACT. PLEASE DESCRIBE THE JONES ACT.

A. The Jones Act (part of the Merchant Marine Act of 1920) requires the use of ships that have been constructed in the United States, fly a U.S. flag, are owned by a U.S. corporation and crewed by U.S. citizens or permanent residents when used for transport of goods by water between U.S. ports. This requirement applies to offshore wind facilities off the U.S., and all the available wind parcels in the Carolinas are similarly impacted. Typically, large pieces such as the turbine nacelle or blades are transported and installed using a jack-up vessel. Because there are no Jones Act-compliant jack-up vessels in use in the United States, the use of an alternate Jones Act-compliant vessel is required and adds complexity to construction. Public Staff suggested that this requirement is a risk to the Companies' ability to construct offshore wind facilities.

Q. HOW DO THE COMPANIES PLAN TO ADDRESS THE SCARCITY OF JONES ACT COMPLIANT VESSELS TO CONSTRUCT OFFSHORE WIND FACILITIES?

A. There are two methods to address the current scarcity of Jones Act compliant vessels capable of constructing offshore wind facilities. First, a Jones Act compliant feeder vessel can transport installation components from port and transfer to an installation vessel at the site. Figure 2 below from the U.S. Government Accountability Office shows an example installation using separate vessels to comply with the Jones Act.

Figure 2: Example Jones Act-Compliant Installation



Source: GAO. | GAO-21-153

Second, the Companies expect that, as the U.S. offshore wind market matures, the Jones Act vessels will become available towards the latter half of the decade. For example, Blue Ocean Energy Marine, LLC., a Dominion Energy Virginia affiliate, is fabricating the first Jones Act compliant vessel, called the Charybdis, for installation of the 2.6 GW Coastal Virginia Offshore Wind project. The vessel Charybdis is scheduled to be completed in 2023, with the subsequent Coastal Virginia Offshore Wind project scheduled for completion in 2026. Furthermore, on June 23, 2022 the Biden Administration launched the Federal-State Offshore Wind Partnership with the goal of growing American-made clean energy. Crucially, the Biden Administration announced specialized financing for "Vessels of National Interest" (in support of offshore wind projects). The lead time to construct a Jones Act compliant offshore wind turbine installation vessel is estimated at 3 years. Given that the development of the offshore wind projects, themselves, has a longer lead time than construction of a turbine installation vessel, the Companies expect the vessel market to catch up with demand.

Q. PLEASE COMMENT GENERALLY ON THE POTENTIAL FOR OFFSHORE WIND PROJECTS TO BE ONLINE BY 2030.

A. The timeline shown in the Carbon Plan Appendix J was presented as an example of a project development timeline. This aligns with the BOEM maximum timeline to submit a COP. As previously mentioned, this represents the maximum allowable timeline. Projects may be completed in a shorter time period; however, this comes with increased risk and the need to perform development work as early as possible and, therefore, requires regulatory certainty to proceed. According to their comments, Avangrid concurs that the development of an offshore wind project should take "roughly 8-10 years from lease acquisition."[3] Such a timeline could put Carolina Long Bay in operation between 2030 and 2032, as represented in the Carolinas Carbon Plan.

The model used to develop the scenarios presented in the Plan was provided with multiple offshore wind capacity scenarios to achieve the 70% reduction goals. At the time of modeling, only one parcel had sufficient development, based on publicly available information, to be deemed feasible for a 2030 commercial operations date. This parcel was limited to 800 MW based on the submitted COP and because the transmission upgrade requirements to accommodate 800 MW of offshore wind was achievable by

[3] Avangrid Comments at 16.

2030. Above that amount, new transmission lines would have to be constructed, which was not achievable prior to 2030. Initially, the 2030 date was not included in the model because of the ownership requirements of HB 951, and the Kitty Hawk phase I was slated to connect to Virginia. However, the Companies adjusted the approach based on stakeholder feedback.

For runs that achieved 70% carbon reduction after 2030, the model was provided an additional 1,600 MW to select based on a generic offshore wind project. At the time, this was based on the official numbers in the BOEM Proposed and (subsequent) Final Sale Notices for Carolina Long Bay. In order to simplify the model, the build-out was presented in distinct phases, demarcated by the 800 MW transmission limitation. From a construction perspective, any development of offshore wind would be performed with the best project management and construction principles.

Q. HOW DO YOU RESPOND TO COST CONCERNS REGARDING OFFSHORE WIND?

A. The projected costs presented in the Plan and used for modeling are high-level estimates based on indicative pricing, industry data and multiple sources. However, one of the key purposes of the proposed development activities is to develop more detailed cost, scope, schedule and engineering estimates. As with any major construction project, projects of this size and scale carry risks, but risks can be mitigated with associated engineering and design studies, including Pre-Front-End Engineering Design ("FEED"), FEED, Site Surveys, Supply Chain Assessment, Port Study, as well as detailed designs. After approval of the SAP, Duke Energy will begin to collect wind, wave and current data that will inform the pre-Front End Engineering and Design. As Site Characterization data is collected through geophysical and geotechnical surveys, this information will inform the engineering and design of foundations, transition pieces and the wind turbine tower. Based on early discussions with engineering firms, we understand this process to be iterative—meaning that we will refine the engineering and the cost estimates throughout the process to develop. In summary, the development activities set forth above will help inform future cost estimates that will be brought to the Commission through a future Carbon Plan proceeding. At that time, the Commission will have the full opportunity to consider any cost concerns along with all other factors in deciding whether to select offshore wind as a resource.

As the U.S. offshore wind market matures, the costs of manufacturing, installation and operational costs are expected to decrease. The extent of cost declines will be driven by maturity in the supply chain and the extent to which onshoring of advanced manufacturing is available at a lower cost than European manufactured components. Early announcements in the southeast are promising; including a subsea cable factory expansion in South Carolina, a Siemens Gamesa wind blade factory in Virginia, existing inter-array cable manufacturing at Southwire in Huntersville, NC. With more than 2,000 parts in a wind turbine, the economic development and supply chain opportunities are innumerable.

VI. CONCLUSION

Q. MR. REPKO, ARE THERE ANY FINAL TAKEAWAYS YOU WOULD LIKE TO SHARE WITH THE COMMISSION?

A. Yes. The Companies believe that it is likely that these three long lead-time resources will be needed to meet the ambitious carbon reduction goals of HB 951 and therefore that it is prudent and reasonable to pursue development activities in the near-term to further develop the resources, pursue their initial regulatory and permitting requirements and refine cost estimates. The Company is not asking for approval of these resources at this time but is requesting approval of the decision to pursue the development activities and to incur costs set forth in Table 1 (Bad Creek II), Table 2 (SMRs) and Table 3 (Offshore Wind) above, consistent with its comments to be submitted on September 9, 2022, and the requested relief in its Application.

If the Companies do not undertake development activities in the near-term for offshore wind, SMRs, and Bad Creek II, these resources will not be available on the timelines contemplated by the portfolios. Preserving these resource options on the contemplated timelines is important to the future execution of the Companies' Carbon Plan.

Q. MESSRS. REPKO, IMMEL, NOLAN, AND POMPEE, DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

Duke Energy Carolinas, LLC and Duke Energy Progress, LLC
Summary of Direct Testimony – Long Lead-Time Resources
Regis Repko, Steve Immel, Chris Nolan, Clift Pompee
Carolinas Carbon Plan
Docket No. E-100, Sub 179

My name is Regis Repko, and I am the Senior Vice President of Generation and Transmission Strategy for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC. I am here today testifying together with Steve Immel, Chris Nolan, and Clift Pompee on the "Long Lead-Time Resources Panel." I will present a summary of my direct testimony and that of Messrs. Immel, Nolan and Pompee.

The purpose of the Panel's testimony in this proceeding is to provide a factual overview of the Companies' plans to increase the amount of pumped hydro storage through the construction of a second powerhouse at our existing Bad Creek I facility, called "Bad Creek II," pursue the development of small modular reactors, known as SMRs, and pursue the development of offshore wind generation. This panel's testimony provides the annual projected expenditures for the development of each of these resources over the next three years.

All three of the resources discussed in this panel require long lead times to develop, construct, and incorporate into the Companies' resource mix as compared to the other resources presented in the Carbon Plan. Specifically, the development of Bad Creek II, SMRs, and Offshore Wind each have lead times of 7-10 years, or longer, compared to the approximate 3-5-year lead times for the more established generation technologies presented in the Plan. The Companies believe we will need an "all of the above" strategy with these three resources and that they will all be needed to achieve HB 951's carbon neutrality goals over the long term. As this panel will discuss in more detail, the Companies are requesting Commission approval of the decision to incur the following costs related to the near-term development work for Bad Creek II, SMRs, and Offshore Wind.

- Development of Bad Creek II includes expanding the capacity of the Companies' Bad Creek I pumped hydro storage facility to include a second powerhouse. To develop this resource, the Companies intend to conduct a feasibility study; develop an Engineering, Procurement and Construction strategy, and continue to develop an application to the Federal Energy Regulatory Commission to relicense Bad Creek I to incorporate the Companies' construction and operation of Bad Creek II.

- To pursue development of SMRs, the Companies must begin work on an Early Site Permit, or ESP, that will be submitted to the Nuclear Regulatory Commission, for a to-be-determined site for this resource; perform a due diligence review to identify a nuclear technology for the SMRs that will ultimately be constructed; and choose a company that will construct the new nuclear technology. The ESP will allow the

Companies to pursue development of a new nuclear resource, regardless of the technology ultimately selected, and is a valuable resource in and of itself.

- To further pursue development of offshore wind generation, the Companies must secure an ownership interest in a lease for a Wind Energy Area, where the offshore wind resource will be located, and initiate and develop various permitting activities, including developing, submitting, and obtaining approval a Site Assessment Plan from the Bureau of Ocean Energy Management, beginning the stakeholder engagement process, developing a Construction and Operation Plan, and initiating an interconnection study process.

Because of the lead times associated with the study, permitting, and construction of the three resources discussed in this panel, the Companies must begin this work to best understand the future costs of each resource and ensure that they will be available within our projected timeframes. By starting the development work on these resources, the Companies will take an important first step towards the delivery of clean energy from resources that are necessary to meet the reliability, least-cost planning, and carbon emissions reduction requirements of HB 951.

The Companies emphasize that we are not requesting that the Commission to select these long-lead time resources for inclusion in the Carbon Plan now. Rather, the Companies are only requesting Commission approval of the decision to incur the costs associated with the near-term development activities for these three resources. This near-term development activity will allow the Companies to take additional critical steps towards initial development work, refining the cost estimates and timelines and then to present such information to the Commission in the biennial 2024 Carbon Plan update or a future Carbon Plan update proceeding. This concludes the summary of this Panel's direct testimony.

MS. LINK: And the panel is now available for questions from the parties and the Commission on the direct testimony.

CHAIR MITCHELL: All right. Avangrid, you're up.

CROSS EXAMINATION BY MR. SMITH:

Q. Good morning. My name is Ben Smith. I representative Avangrid Renewables, LLC in this docket. My client's interest in this docket are relatively limited to offshore wind development for the Carbon Plan, so my questions will mostly be focused there. That being said, some of these questions will be a little bit broader in scope, but relative to your direct testimony.

I'd like to start with some background questions, and anyone of the four of you I think could answer this.

How many people does Duke Energy Progress have working full-time on offshore wind development at this time?

MS. LINK: Your Honor, I'm gonna object. I'm not sure what the relevance of the number of people of one Company working on offshore wind development is.

MR. SMITH: I think it's relevant to the extent that they're asking for near-term action plans to the long-lead development including offshore wind to talk about where their status is right now.

CHAIR MITCHELL: All right. I'll overrule. I'll allow the question, and do your best to answer it.

THE WITNESS: (Regis Repko) There is a team within our commercial affiliate working on that. I do not know the exact numbers. I also know that they are, you know, engaging industry expertise with the development activities they're progressing after the acquisition of the lease area.

Q. And the commercial affiliate, is that Duke Energy Renewables?

A. Duke Energy Renewables Wind, LLC.

Q. Okay. And so just to be clear, within the two Duke regulated utilities that presented the Carbon Plan, you're not aware of any offshore wind development personnel that are currently employed?

A. Not direct development personnel, in the energy area at least, correct.

Q. And taking that to the question of permitting BOEM permitting, getting SAP, getting COPs, does -- did Duke regulated entities have personnel who are currently employed to do that permitting work?

A. That permitting work is being pursued per our commercial affiliate.

Q. Okay. So Duke Energy Renewables --

A. Wind, LLC, correct.

Q. -- Wind, LLC.

And how many projects has Duke successfully permitted in federal waters at this point?

A. We have not pursued permitting any projects in federal waters at this point.

Q. And talking to the four of you in this panel, do any of y'all have a background in offshore wind development?

A. None of the four of us on this panel do, but personnel within our commercial affiliate, Duke Energy Renewables Wind, does.

Q. Thank you. All right. I'm gonna move on to some questions about permitting, and specific to parts of the direct testimony. And, Mr. Pompee, I'm gonna speak to you first, and probably mostly. Moving to page 47 of your direct testimony. Just let me know

when you're there.
A. (Clift Pompee) I'm there.
Q. Okay. You respond to the question, "What are the near-term activities and costs associated with the development activities for offshore wind?" And over the next few pages, you request approval to prepare a site assessment plan, or an SAP, and a construction and operations plan, or a COP, for an offshore wind resource, which you also request in the Carbon Plan.
Can you confirm that the Bureau of Ocean Management [sic], or BOEM, requires these actions of any offshore renewable energy leaseholder?
A. I can confirm that.
Q. Thanks. And apologies, I'm having a little bit of trouble hearing you, if you wouldn't mind speaking a little bit into the mic.
MS. LINK: If you move the mic closer, Mr. Pompee.
THE WITNESS: Okay. Is that better?
Q. That's better, thank you.
A. Yeah, I can confirm that.
Q. Thank you. And is it your understanding in your work that nonregulated utility developers regularly execute this type of offshore wind permitting

work?

A. I'm aware that, yeah, this work has been executed in the U.S., yes.

Q. And so since these permitting actions are required of any offshore renewable energy leaseholder, can you please explain why it's necessary for Duke regulated to assume ownership of a lease area in order to perform those actions? Or I think you're saying -- actually, I'm gonna restate that question based on your earlier answer from Mr. Repko.

Y'all are saying that the -- your affiliate, Duke Energy Renewables Wind, will be taking the permitting work on?

A. (Regis Repko) They are progressing with that at the current time. I do not know at the rate of which that's progressing.

Q. Sure. Part of the testimony sort of indicated that there were four steps that had to happen to, sort of, move through offshore wind. I think it was four. And number one -- it was listed in order of number one, there's a conveyance that had to happen, and then you would move forward with these different permitting activities.

Is it fair to say that when you were

describing those four, you might not have meant them in that order, and it was just generally four things that had to happen? And I can find the reference point, but I'm just trying to short-circuit a lot of these questions.

MS. LINK: Chair Mitchell, I think it would be helpful if he could point the witnesses to the testimony.

MR. SMITH: Will do. Just give me one second.

(Pause.)

Q. All right. I think I found it. Page 11 to page 12. And I believe this is Mr. Repko's testimony, but apologies if I'm off on that. Okay.

Reading from page -- from line 22, "The primary near-term development activities for offshore wind are as follows. Number 1, secure an ownership interest in a lease for a wind energy area where the offshore wind resource will be located; number 2, initiate and develop permitting activities which will consist of, A, developing and submitting an SAP and beginning to engage with stakeholders, B, developing a COP, and C, initiating an interconnection study process; and 3, obtaining approval of an SAP from the

Bureau of Ocean Energy Management."

Does that a fair -- did I recite your testimony accurately?

A. You did.

Q. Okay. And so I guess what I'm asking is, it sounds like number 2 is occurring right now on your list prior to number 1.

A. Number 2, the development around really the SAP is progressing at some rate within our commercial affiliate, the rate at which I'm not certain.

Q. Okay. But is it Duke -- and I'm talking about Duke regulated, is it your position that you must secure an interest in a wind energy -- wind energy area prior to these permitting activities to be completed?

A. Yes. The acquisition for the Companies to secure a wind energy area lease is essential to make sure that those development activities progress at the rate necessary to make offshore wind an option to the Commission for selection as part of the Carbon Plan.

Q. All right. Thank you. When you talk about to make sure that offshore wind is an option to the Carbon Plan, could you explain, in what way would it -- how could it progress where it wouldn't be an option?

A. It would progress at the point where the development and subsequent activities would make it viable in the time frame that the Commission selects to meet the goals of the House Bill 951.

Q. Understood. So I'm gonna move on, and I might come back. I'd like to talk a little about the lease areas. And, Mr. Pompee, this might be you, but it could be anyone.

How many wind turbine positions could be located within the Duke Energy Renewables own Carolina Long Bay lease area?

A. (Clift Pompee) I'm sorry, can you clarify what you mean by wind turbine positions?

Q. How many wind turbines, the large sort of fan-looking things that spin and produce energy.

A. Yes. So that number is variable, and it's based on technology development. So you have to look at what's available today and what's gonna be available in the coming years. So, you know, it could be anywhere from something in the 60s to something in the 90s. And you have to do the work to determine your wind profile such that you can determine how best to maximize a wind energy area.

Q. Thank you. And can you talk a little bit more about what work has been done by Duke regulated to

get that profile?
A. The Duke regulated group, we looked at high-level potential layouts for the area prior to the lease execution, but the work to get to any actionable level has to happen from here going forward. And that's really what we're asking for. As, you know, Mr. Repko mentioned, to maintain the timeline for availability of wind to be selected if the Commission selects offshore wind.
A. (Regis Repko) It is a key point that we have verified, that the lease area of Carolina Long Bay that was acquired by our commercial affiliate can meet all of the needs in terms of the capacity, the generation that has been modeled thus far in the Carbon Plan.
Q. Thank you. And how many of those -- you spoke about 60 to 90 and spoke about doing some of the development.
How many of the wind turbine positions in the Duke Energy Renewables Wind-owned Carolina Long Bay lease area are at risk of being lost due to the 24-nautical-mile viewshed buffer that's currently being requested by various North Carolina delegates?
A. (Clift Pompee) Yeah. That's an interesting question, because the number is not so much dependent

on the 24 nautical miles, it's really dependent on the stakeholder work that has to happen to really determine what the best positioning is from a viewshed perspective. The 24-nautical-mile number is based off of a static understanding of what was presented in other projects, and it's really more dynamic than that.

There's work that has to be done to determine what the viewshed is, and that's when you would look at how many wind turbines would be put out there as well as how to best meet the output requirements.

Q. So is it fair to characterize your testimony that Duke is seeking to have a static 24-nautical-mile viewshed buffer changed to reflect a more dynamic model that you see for your project?

A. No, that is not fair. I think what I was alluding to is that Duke Energy would continue to do the work, as we have always done, to work with our stakeholders to ensure that we meet their needs. And that 24 nautical miles is just a number. The real work has to be to ensure that the communities that we serve are heard and that we meet their needs and their concerns.

Q. And what stakeholder activities are currently ongoing related to the 24-nautical-mile viewshed buffer?

A. I'm not aware of the specifics that are currently occurring with the Duke Energy Renewables Wind.

A. (Regis Repko) Again, there's a couple key aspects to keep in mind. So opposition relative to offshore wind projects is common. The Vineyard Wind project by Avangrid Renewables had opposition as well. And again, through a stakeholder process, you work to reconcile that through a number of different ways.

The second point is that BOEM, in the initial input before the auction ever the Carolina Long Bay, recognized the stakeholder input around the viewshed concerns and extended that out to 18 nautical miles.

A. (Clift Pompee) Right. They had to go 20 miles.

A. (Regis Repko) And then the third point I would bring up, it's relevant around the Carolina and Long Bay lease, is that it's a triangle shape. And our commercial affiliate sought that lease very purposefully, that any extension of exclusion area to account for viewshed would result in a minimal loss or a lower loss of the number of turbines.

Q. Let's talk about that point, then.

CHAIR MITCHELL: All right. Mr. Smith, let's break. Let's stop now. We're gonna take our morning break. Let's go off the record and come back in at 11:15.

(At this time, a recess was taken from 11:00 a.m. to 11:17 a.m.)

CHAIR MITCHELL: All right. Let's go back on the record, please. Go ahead, Mr. Smith.

MR. SMITH: Thank you.

Q. I'm actually gonna go back. I was able to review my notes. I'd like to go back to permitting for just a minute and then go back to the viewshed buffer.

Are you-all familiar with the BOEM requirements for SAP and COP permitting?

A. (Regis Repko) Yes. Those are prescribed in the Code of Federal Regulations.

Q. And within those requirements, regardless of a conveyance to Duke regulated, Duke Energy Renewables Wind is required to complete an SAP and a COP within certainly time frames, otherwise they risk forfeiture of the lease, correct?

A. There are time frames prescribed under the BOEM process and per the Code of Federal Regulations. BOEM does have discretion to extend those time frames, and they have done that for projects.

Q. Okay. And those time frames, is it your understanding that it's -- SAP must be submitted within a year of the lease acquisition, and a COP must be done within five years of the SAP; is that your understanding?

A. That is correct. And again, BOEM does have discretion and has granted extensions to those time frames.

Q. I'm gonna move on back to the viewshed risk. All right. So before we took our break, you had mentioned that the Carolina Long Bay lease area is triangular shaped. And I'm not gonna restate what you testified to, but I'm gonna ask, sort of, about if the 24-mile static nautical -- sorry, excuse me -- 24-nautical-mile static viewshed buffer is, sort of, held up and sort of required for the Carolina Long Bay lease area, Duke Energy Renewable Wind Carolina Long Bay lease area, do you know -- did you say if you know how many turbines would be lost?

A. So I did not say. So a couple key points. So the 24-nautical-mile exclusion area is not required and not enforceable because it's out in international waters beyond the 3-mile time frame for state jurisdiction. However, it will be our intention to develop any offshore wind project commensurate to the communities that we serve and through a stakeholder process.

Q. So just so I have this clear, if you are following through with that static 24-nautical-mile viewshed buffer, do you know how many -- how that would affect the Duke Energy Renewable Wind Carolina Long Bay lease area and the amount of turbines it might have?

A. I do not.

A. (Clift Pompee) I'm not aware of a particular number, but I will say, and, you know, to reiterate or to back-up what Mr. Repko mentioned, beyond that, you know, he did mention the shape, right? The -- any loss of area is minimized because of the shape of the wind energy area as well as -- you know, these things are dynamic, and there are various ways that you can set up the wind turbines, different wind turbine sizes to optimize the energy that you get out of the wind energy area.

So, you know, we seem to be stuck on the nautical mile buffer, but I don't think that's the full story of how you optimize a wind energy area.

Q. I agree. Are you aware of any current

North Carolina delegate protests to the Kitty Hawk lease area?

A. I am not.

Q. And is it your understanding that the Kitty Hawk -- the Kitty Hawk wind lease area falls outside of the 24-nautical-mile viewshed buffer?

A. It is.

Q. Okay. So let's say half of the turbine positions were lost to viewshed risk, and the maximum project capacity in the zone was less than even one right size HVDC project.

Would you still consider that to be a prudent investment on behalf of ratepayers?

MS. LINK: Objection. Chair Mitchell, this hypothetical assumes many different facts that really have no bearing on -- there's nothing in the record that would yield that these are reasonable facts for a hypothetical.

MR. SMITH: I can move on.

CHAIR MITCHELL: Okay.

Q. I want to go to page 42 of your direct testimony. There's a statement that says, "The relatively high" -- excuse me -- "high-capacity factors and lower intermittency for offshore wind," and I'll cut it off there, because that's where these questions go to.

Can you explain the relevance of net capacity factor when assessing a generation asset, and in particular, an offshore wind asset?

A. Sure. So in my statement where I say relatively high-capacity factor and lower intermittency, I go on to talk a little bit more about how offshore wind really complements solar. And in the Carbon Plan, there's a high level of solar that is being proposed, and offshore wind very well complements that. On the capacity factor side, the higher the capacity factor, the more energy you can get out of a wind energy area.

Q. And do you know the relative net capacity factors profiled for the Duke Energy Renewable Wind's Carolina Long Bay area and the Kitty Hawk lease areas?

A. I do not, and I'll elaborate on why I don't. Specifically, the work that we're proposing to be done as part of the SAP involves meteorological work and assessment work that would further refine the Carolina Long Bay wind energy area that would give us the information to be able to say definitively what the net capacity factors are.

Any numbers that are out there currently on net capacity factor are based off of available wind data that is outside of the wind energy area, so they're subject to refinement, and that's really what we're asking for.

Q. I want to clarify. You, I think -- and correct me if I'm wrong, did you just say that any numbers that are out there are outside the wind energy areas?

A. To my knowledge to date, there have not been any meteorological wind studies that have been done inside the wind energy area. Any potential net capacity factors are based off of wind data from towers that are outside the of Carolina Long Bay wind energy area.

Q. Okay. And getting back to NCF a little bit, NCF is net capacity factor. Sorry, I know, it'll be death by acronym.

Would you agree the most important input to determining an offshore wind facility's NCF is its wind speed?

A. No, I would disagree. I think wind speed is one aspect of net capacity factor. Another important aspect is the layout of the site, how you choose to put wind turbines. And another one is, when you get into engineering, you select a wind turbine that is optimized for the particular wind speed.

Q. Thank you. And I think you've answered this question, but -- so apologies, and any objection.

But have you had a meteorologist provide a report on the wind speeds and NCFs of the Carolina Long Bay or the Kitty Hawk lease areas?

A. No, we have not. And again, I'll reiterate, I think the long-lead work that we're asking for approval to undertake is specifically so we can get to that level of detail and be able to, you know, ascertain what those net capacity factors would be.

Q. Thank you. And have you looked at the publicly available data resources, such as NREL or Energy.gov, at the wind speed in the -- in the Duke Energy Renewable Wind's Carolina Long Bay lease area and in the Kitty Hawk lease Area?

A. Yes, we have.

Q. And how do they compare?

A. The Kitty Hawk parcel has a higher wind than Carolina Long Bay, and so would expect a bit of a higher capacity factor.

Q. So it's fair to say that publicly available third-party data suggests that the Carolina Long Bay lease area has a material lower wind speed than the Kitty Hawk lease area, and so Kitty Hawk is very likely to have a materially better NCF?

MS. LINK: Objection that the question is vague. "Material" is not defined.

MR. SMITH: I will restate without the word "materially."

Q. Is it fair to say that --

CHAIR MITCHELL: Mr. Smith, let me rule on the objection. I'm gonna sustain the objection. Restate it, and also do your best to avoid a compound question.

Q. Is it fair to say that, based on publicly available third-party data, that the Carolina Long Bay lease areas have materially lower wind speeds than the Kitty Hawk lease areas?

MS. LINK: Renew my objection, Chair Mitchell.

CHAIR MITCHELL: All right. And I'll sustain it. Mr. Smith, ask it in a different way, if you can.

MR. SMITH: Sure. I restated something that I shouldn't have.

Q. Mr. Pompee, is it fair to say the Carolina Long Bay lease area has profiled in publicly available third-party studies lower wind speeds than the Kitty Hawk lease area?

A. It is fair to say that. That is available data, and I believe, you know, we're talking about the net capacity factor. And I'll just remind you, Mr. Smith, that, you know, there's more than just a particular wind speed that goes into the net capacity factor, although it is an important piece. The actual number, right, the number, the actual net capacity factor is not knowable at this point because the work hadn't been done.

Q. But based on publicly available third-party data, Kitty Hawk is likely to have a better NCF than Carolina Long Bay lease area?

A. That is correct. And I think the -- the quantifiable number is unknowable, how much better.

Q. Has Duke regulated done any -- actually, scratch that. I'm gonna move on.

Has Duke made their own estimation of equivalent CAPEX value to reflect materially different net capacity factors between lease areas?

A. Yes. I believe we looked at that.

Q. And can you tell me what the conclusions are with regard to CAPEX comparisons between Kitty Hawk and Carolina Long Bay?

A. Without getting into the specific numbers, I don't have on the top of my head, I think what we established was -- you know, as I mentioned, there are very many factors that go into one of these projects. We felt that, on a CAPEX perspective, the lower net capacity factors were offset by the shorter transmission distances from a CAPEX perspective, Carolina Long Bay to Kitty Hawk.

Q. And to your point about the important factors in considering net capacity factor, including design, it's fair to say that all developers could design their lease areas in the optimal manner, correct?

A. Absolutely.

Q. I'm gonna move on to page 49 of your direct testimony. Are you there?

A. Yes.

Q. There's a table of cost estimates at the bottom of page 49; do you see that?

A. I do.

Q. Referring to the table, how did Duke estimate the $62 million figure for development expenses?

A. So we looked at what type of work would be required in the next couple of years, and we gave it a high-level estimate as to what would be required to be done in the next couple of years to get the development of the Carolina Long Bay lease area to a point where we felt like we could come back to the Commission with better, more refined information.

Q. So would you expect a similar projection of development costs to apply to either of the other two lease areas?

A. So this is just based off of our estimate. I wouldn't venture to say what other entities are spending to develop their lease areas.

Q. Sure. But it's Duke's position that this development cost is specific to Duke Energy Renewable Wind's Carolina Long Bay lease area?

A. No. These are our estimates on the regulated. We don't know what Duke Energy Renewables Wind has allocated or what their estimates are to perform this work.

Q. I'm sorry, I might have misstated the question.

I guess I'm asking, is this $62 million figure specific to the Duke Energy wind -- Renewable

Wind Carolina Long Bay lease area?

A. Yes. Specifically, we're talking about the work to get the lease from -- to get the wind energy are from lease to SAP.

Q. Okay. Thank you. All else being equal -- actually, scratch that.

In terms of making decisions about near-term development for long lead, would you agree that a lease area with similar development, capital and operational cost with a better wind speed would deliver more value to ratepayers?

A. I would disagree. As I mentioned a few minutes ago, there are lots of factors that determine what the value is going to be. I think there's -- obviously total CAPEX is part of that. And if you look at the two lease areas, there are significant differences that would go into the CAPEX.

And I think we would, again, say that the net capacity factor is offset by the longer transmission line going from the facility to the point of interconnection.

Q. Okay. Thank you.

A. (Regis Repko) I would also add that the criteria for House Bill 951 is not the lowest cost per any single resource, it's the lowest cost path. So you can actually have just the necessary component of offshore wind to meet the desired decarbonization goal and time frame. It might be slightly higher in cost, but still contribute to have an overall lower cost path than a fully larger developed project.

Q. Thank you, Mr. Repko. I'm gonna move on to page 47 of your testimony. If you could turn there, please.

A. (Witness complies.)

(Clift Pompee) I'm there.

Q. On page 47, you say, "Assuming the Commission agreed that it is prudent and reasonable to pursue further offshore wind development activities, the Companies would seek affiliate approval from the Commission to transfer the Carolina Long Bay lease area from Duke Energy Renewables Wind, LLC."

I was hoping you could take me through, what does that conveyance look like from a regulatory perspective?

A. So I'm gonna go ahead and defer this question to Mr. Repko who I think is better equipped to answer.

MS. LINK: And I'll just note, Chair Mitchel, that this may get into also a legal response in terms of what an actual affiliate transfer application looks like. So to the extent Mr. Repko can answer it, he will, but there's also a legal component to it.

MR. SMITH: I am only asking about regulatory actions that Duke regulated would need to make.

CHAIR MITCHELL: All right. Proceed with the question.

Q. Would you like me to restate?

A. (Regis Repko) Please.

Q. On page 47, it says, "Assuming the Commission agreed that it is prudent and reasonable to pursue further offshore wind development activities, the Companies would seek affiliate approval from the Commission to transfer the Carolina Long Bay lease from Duke Energy Renewables Wind, LLC."

Can you take me through what regulatory activities Duke regulated would have to do for that conveyance?

A. Yes. As I understand it, it's an affiliate transfer, right, so it is a legal transaction between the two -- between our commercial affiliate and the Companies, or the Company, DEP; and then it would be a subsequent acceptance of that affiliate transfer by the Commission.

Q. And what other -- actually, scratch that.

Would there be any other requirements, from a regulatory perspective, beyond the affiliate transaction review by the Commission for Duke to move forward with the Duke Energy Renewable Wind's Carolina Long Bay lease area wind development?

A. I believe that transfer would also have to be filed and recognized by BOEM.

Q. But is there any sort of further certification that would have to be done at the North Carolina Utilities Commission, like a CPCN filing, a CEPCN?

A. Not that I'm aware of for the affiliate transfer.

Q. Actually, I was talking about the development of Carolina Long Bay.

What would have to be done for moving forward with that development?

A. So what we're asking for in this proceeding is a decision to incur the cost associated with the development of the three long-lead items, offshore wind being one of them. So we're really looking for a decision direction by the Commission that they want offshore wind to be considered as an option and developed to that extent to make it available as an option. And we have those -- we provided a view of what those development activities look like and an approximate cost for that.

So in terms of the actual cost incurred and recovery of that, we would be looking for a separate proceeding, whether that be another Carbon Plan or rate case or anything of that nature, that we would be required to demonstrate the reasonableness and prudency of those costs associated for the development of those resources.

Q. Okay. Thank you. I'm gonna move on to timing.

Are you familiar with HB 951's requirement that Commission take all reasonable steps to reach a 70 percent carbon reduction goal by 2030?

A. Yes.

Q. In your testimony, at the bottom of page 43, you reference the Dominion CVOW project. Let me know when you're there.

A. (Witness peruses document.)

There.

Q. The CVOW project was inquired [sic] in 2013 and hopeful to achieve a 2026 COD, which is a 13-year development timeline; is that correct?

A. Correct.

Q. And in your testimony, on the same page, you reference an 8- to 10-year minimum timeline to achieve COD from lease acquisition; isn't that right?

A. That is correct.

Q. Is it your understanding that the Kitty Hawk lease area was purchased at lease auction in 2017?

A. (Clift Pompee) Yes. So this was my testimony. I am familiar with that.

Q. Okay. And, Mr. Pompee, is it your understanding that Kitty Hawk has been developed ever since, including achieving both SAP and COP submissions as well as significant engineering studies, same studies which you call out on page 55 of your testimony as important derisking agents?

A. It is my understanding that Avangrid Renewables has submitted a SAP that was accepted, and has also submitted a construction operation plan, a COP, that has not yet been approved.

Q. And the Carolina Long Bay lease area was only purchased this past May and has had significantly less time than Avangrid Renewables has had to do the permitting work that you just referenced?

MS. LINK: Objection. Using the word "significant," again, it's vague, it's not defined.

Q. Would you agree that --

CHAIR MITCHELL: Let me rule.

MR. SMITH: Excuse me.

CHAIR MITCHELL: That's okay. Let me rule. Do you have a response to the objection that you'd like me to hear?

MR. SMITH: I can restate the question differently.

CHAIR MITCHELL: All right. So I'll sustain the objection. Please restate the question.

Q. Would you agree that Duke Energy Renewables Wind has had less time to do their SAP and COP permitting work than Avangrid Renewables has had for Kitty Hawk?

A. Yes, I would agree to that. And I would also state that, you know, the timeline as laid out in my testimony, still stands at 8 to 10 years.

Q. And moving to page 50 of your testimony. You make a statement that -- are you there?

A. Yes. Can you also refer me to the line, because it's hard for me to follow?

Q. Sure. Lines 19 to 20.

A. Yes.

Q. You state that to try and -- or am I characterizing your testimony correctly to say that you -- to try and construct a project out of the Duke Energy Renewable Wind lease ready -- area to be ready to deliver power by 2030 could present significant financial risk for the Companies and its customers?

A. Yes, that is what I stated. And, you know, in my testimony I stated that, you know, the earliest time frame that we would expect Carolina Long Bay to have commercial operations is by year-end 2030 based on an 8- to 10-year development cycle. There are significant risks with that, in terms of procurements prior to getting final BOEM COP approvals. So yes, that is --

Q. So given all of what you just said and the 2030 deadline we just discussed, how do you respond to the concern that the Duke Energy Renewables Wind lease area is not the best suited option to achieve HB 951's required timeline?

A. I think they're --

MS. LINK: I would object. The 2030 is not -- the characterization that it's a deadline. It's an interim target in the statute.

CHAIR MITCHELL: All right. Mr. Smith?

MR. SMITH: We've taken the position that the 2030 is a deadline. So I guess I would ask -- I guess I could, you know, submit that it's a legal argument, but I wouldn't mind restating the question under -- within the guidelines that --

CHAIR MITCHELL: All right. So I'll sustain the objection. Restate your question.

Q. So restating it. Apologies if this gets a little marble-mouthed.

How do you respond to the concern that Duke -- that the Duke Energy Renewable Wind's lease area is not the best-suited option to achieve the 2030 70 percent reduction?

A. (Regis Repko) If I may, I will answer that. We acknowledge in the Carbon Plan, Appendix J for wind, that, if the 2030 date is the date that the Commission chooses, that a parcel that is further along in development would be the most likely course of action. That is the Kitty Hawk parcel.

However, beyond that, any extension beyond that, 2032 or beyond, allows for options, including Carolina Long Bay, that can be developed in both time frame and scale at the Commissioner -- at the Commission's choosing by the Companies.

Q. Thank you. Okay. Moving to some cost-effective question -- cost-effectiveness questions.

Would you agree that, compared to solar and other fuel resources -- and this could be for either Mr. Repko or Mr. Pompee -- offshore wind is a time- and capital-intensive asset class?

A. (Clift Pompee) Yes.

Q. Has Duke Commissioned any third-party studies to ensure that your near-term action to acquire Carolina Long Bay from Duke Energy Renewables Wind is the most cost-effective solution for ratepayers?

A. (Regis Repko) Again, I will go back to our modeling, in terms of the amount of offshore wind within our models. So we have very deliberate portions of offshore wind that is included throughout our modeling portfolios that contribute. And we've shown the cost of each, in terms of how that contributes.

Again, I'll make the point that the criteria of House Bill 951 is not the lowest cost of a wind project or a solar, it is the least-cost path, the cost of the overall portfolio to achieve the carbon reduction goals.

Q. I don't think anyone would disagree with that.

So if you haven't done any further studies beyond modeling, and correct me if you have, can you explain to me why acquiring a lease made later in time for an offshore wind lease area without permitting it and potentially worse project fundamentals is a good deal for North Carolina ratepayers?

MS. LINK: Objection. It's a compound question. There's multiple facts that are not in evidence.

MR. SMITH: Well, I disagree. We've established that the offshore wind lease area is -- was made -- was acquired later in time. The permitting has not been completed. And we've talked about project fundamentals, we can have a disagreement about whether good or bad on wind factor and whether to rely on NREL and Energy.gov wind speed characterizations. But I do think that it relied upon facts that are before the Commission.

MS. LINK: And the Kitty Hawk permitting is not completed either.

MR. SMITH: Kitty Hawk's witnesses will have the opportunity to testify as to the state of -- the status of the Kitty Hawk wind lease areas' permitting.

CHAIR MITCHELL: Let's do this. I'm gonna overrule the objection, but I'm gonna direct you to break your question up so that you don't have compound question. State it clearly so the witness understands what you're asking and he can answer, and we'll give the response the weight it's due.

Q. Can we agree that the Carolina Long Bay lease area was acquired in a BOEM auction later in time than the Kitty Hawk?

A. (Clift Pompee) Yes.

Q. And can we agree that the Carolina Long Bay wind lease area permitting, as far as you know, has not been completed?

A. Yes, I can agree to that.

Q. And can we agree that wind speed factors contained and published by NREL and Energy.gov show higher wind speeds for the Kitty Hawk wind lease area than the Carolina Long Bay lease areas?

A. Yes. And I will add again, because I believe I addressed this earlier, that the wind speed is only a factor. And specifically, there's one other factor that negates the wind speed differences between the two areas.

Q. And what is that other factor?

A. It's the capital cost of the longer export cable from the offshore wind farm to the point of interconnection.

Q. And can you characterize the difference in cost between the two?

A. I can. So in Avangrid's direct testimony, they actually had an arithmetic error. The characterization was each percent of net capacity factor represented $50 million in CAPEX, which I'm not disputing. I think that's close to our numbers. The testimony stated that Kitty Hawk net capacity factor was 43 percent versus Carolina Long Bay's 36 percent.

As I stated earlier, that's not something that's knowable right now because the work hasn't been done for the 36 percent. But even if we accept that, that represents a 7 percent difference in net capacity factor at $50 million dollars per percent of net capacity factor. And that's directly in Avangrid's testimony. They stated that the difference in CAPEX is $850 million. The arithmetic doesn't work. It's $350 million.

The export cable from Kitty Hawk to the point of interconnection, which you heard from witness Roberts is New Bern, at least the way we see it in terms of least-cost path, has the Kitty Hawk export cable at roughly twice the length of Carolina Long Bay. You would have to use a high-voltage DC, which works out to roughly $340-ish million of additional CAPEX for the double-length high-voltage DC export cable.

Q. So without conceding any of Kitty Hawk's points they made in their testimony, am I understanding you to say that there is still a delta between the cost associated between the potential value of the Kitty Hawk lease area versus the cost of what you claim is the longer interconnection cost process?

A. No, I don't see a cost delta. What I see is high-level estimates that are roughly within, you know, margins of error around $350 million in terms of offset.

Q. So $350 million, $340 million, give or take a few million bucks?

A. So I think that, you know, at this point we are not looking at, you know, estimates that are project specific. We're looking at high-level estimates. $350 million could easily be 328. 338 could easily be 360, right? We don't have any indicative pricing. We haven't done, you know, procurements to know exactly.

These are just estimates based off of GIS data of what the cable lengths could be, and based off of public information of what these high-voltage DV cables run on a per-mile basis.

Q. And it's your understanding -- or is it your understanding that Avangrid Renewables contests Duke's position on the amount of cabling that needs to be done?

A. Yes, it is. And that was really the point of my statement here, is that the -- without getting into too much detail, there are lots of concerns with the proposed path that Avangrid is suggesting to get to their lower export cable length. Specifically going through the Pamlico Sound and Neuse River. We think there are significant environmental concerns associated with that proposed path.

Q. So would it be fair to say that a third-party transparent study of the three different wind lease areas might lead us to a conclusion about these different things?

A. I don't think that's necessary because the process, itself, for getting the permitting is very clear, in terms of, if you're going to disturb environmentally somewhere, like the Pamlico Sound that has -- relies a lot on fishing, there's wildlife, that you should be seeking alternatives. And only if there are no alternatives would you do that. I don't think we need a third-party study to tell us that you would -- the alternative is to go through the Atlantic Ocean.

Q. Okay. So given the high stakes involved for ratepayers upon embarking on an offshore wind project, which you've done a very good job of sort of outlining some of the risks involved here, and the fact that there are at least two options available to North Carolina ratepayers, in terms of Kitty Hawk and Carolina Long Bay, do you agree that it's imperative to choose the better of the two options to serve ratepayers in accordance with House Bill 951?

A. (Regis Repko) I'll answer that. There has not been an explicit statement by Avangrid that they are willing to sell the Kitty Hawk parcel. They have made expressions of interest, but they have not clearly stated that they are willing to sell. We don't know if they would sell, we don't know at what price. We don't know at what time frame, nor can they be compelled to sell.

So if we go back to September time frame of last year, BOEM began communications that they intended to auction the Carolina Long Bay. It was called Wilmington East then, but I'll stay with the Carolina Long Bay parcel. So at that time we were aware of that. In December comes legislation of House Bill 951. And with that auction -- the reason BOEM was auctioning the Carolina Long Bay early in this year, 2022, is because there was a federal moratorium on offshore energy exploration that took effect July 1st of this year.

And what that means, or what that meant at that time, there would be no opportunity for further offshore wind parcels for up to 10 years. That is the length of the moratorium. So with that lens, that we have House Bill 951, offshore wind could potentially be a component of that and not have the option, we -- and the lease coming around Carolina Long Bay, the senior management of the Company directed that all options for a wind energy area be assessed and pursued.

The outcome of that evaluation, assessment, and pursuit is that we participated or we had -- there was direction that our commercial affiliate participate in the auction for the Carolina Long Bay. The commercial affiliate, Duke Energy Renewables Wind, won the parcel. So there was a parcel immediately available to the Company. It is available at cost. That cost was demonstrated to be at market for a lower price of the two in the -- in the auction that was conducted by a third party.

So it is -- it is the clearest and most straightforward path for offshore wind -- for the Company to develop offshore wind to a scale and time frame at the discretion of the Commission.

Q. Thank you, Mr. Repko.

At the beginning of that answer, you referenced that Avangrid Renewables has not taken a position that they would like to sell the Kitty Hawk wind lease area; is that right?

A. That is correct. They have not made an explicit statement in their testimony that they would sell.

Q. Do you have the Avangrid Renewables direct testimony in front of you right now?
A. I do not.
MR. SMITH: Chair, I didn't anticipate that he would reference Avangrid Renewables' direct testimony, so I don't have copies for the witness. Can I ask questions on it subject to check?
MS. LINK: Can you show him one copy?
CHAIR MITCHELL: Do you have a copy of the testimony that you can put in front of him?
MR. SMITH: Mr. Snowden is gonna help me out.
CHAIR MITCHELL: Let's let his counsel look at it a swell.
(Pause.)
Q. Okay. I have just handed you the direct testimony of Michael Starrett and Becky Gallagher; is that correct?
A. That's correct.
Q. And this testimony was made on behalf of Avangrid Renewables, LLC; is that correct? You can see the top of the page.
A. That's correct.
Q. Okay. I'm gonna begin reading at line 3.

"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."

Answer: "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."

Do you see that testimony?

A. I do.

Q. Can you explain the delta between what this testimony says and your position that Avangrid Renewables says that it is not explicitly for sale?

A. Yes. It says it's open to manners of transaction. It talks about reasonable terms, fairly values. So there is nothing -- I mean, all those are subjective and, you know, subject to negotiations. So there is no certainty that it would sell. It also includes transactions such as PPAs that are not within the realm of House Bill 951 prescriptions of ownership.

Q. We can discuss the prescription of ownership for -- I believe you said it was sited in international waters, offshore wind at a different time. But I want to focus on sort of what you're saying with regard to open any manner of transaction that is on reasonable terms.

Is it your position that Avangrid Renewables shouldn't be allowed to negotiate for the sale of the lease area?

A. So our position is that, again, with that -- the backdrop of what transpired around the timeline of House Bill 951, we pursued all options for wind energy area lease. And when no other options were available to us, we elected to -- we decided to participate in the BOEM auction for the Carolina Long Bay wind energy area to ensure that offshore wind was available for the Commission's discretion for the Carbon Plan.

Q. Okay. So just to get back to your earlier point about Kitty Hawk not explicitly being for sale.

Would you agree that it would be explicitly for sale following a negotiation between two parties, based on this testimony?

A. I can't say where those discussions would end.

Q. All right. I'm gonna move on. All right. Going back, and this is a -- goes to the request that's made in the Carbon Plan about near-term actions to, sort of, enable offshore wind.

Has Duke Commissioned any third parties to ensure that their Near-Term Action Plan to acquire Carolina Long Bay from Duke Energy Renewables Wind is the most cost-effective solution for ratepayers?

MS. LINK: Objection. I think that's been asked and answered. I think he asked that about 15 minutes ago.

MR. SMITH: All right. I'll move on. I don't recall asking that, but I'll take your word for it.

Q. For the Carbon Plan, are there any generation or ancillary service, sort of, projects that are -- actually, let me strike that and start that question over a little more clearly.

Are there any generation assets in Duke's Carbon Plan that are going to be subject to an RFP process?

A. Yes.

Q. Can you tell me about those?

A. I mean, generally, you know, there are -- there's the exception carve-out relative to solar. But even -- even -- even within the realm of the ownership aspects of the utilities, we go through RFP competitive bid events for EPC services and things of that nature. And we would do that with any development of an offshore wind project as well. So resources expertise, we would seek that out, go through a competitive bit, particularly for construction and development activities.

So really broadly across the whole generation portfolio replacement, there would be competitive bidding such as RFPs associated with it.

Q. And what about a type of build-own transfer structure, anything like that? Is there anything like that that's gonna happen commensurate with the Carbon Plan request of Duke?

A. Build-own transfers are an option. As a matter of fact, we have had outreach by European developers of offshore wind that were interested in a build-own transfer model relative to the Carolina Long Bay parcel.

Q. And is that something that you'd be open doing to any of the offshore wind lease areas off the coast of North Carolina?

A. Again, it's our desire that it's appropriate from an ease and simplicity and a time frame standpoint that we develop the Carolina Long Bay parcel.

Q. So you're bypassing a more competitive structure?
A. No. I'm reflecting on the history of what transpired, in terms of us pursuing and evaluating lease options.
Q. Would Duke be interested in a joint ownership venture on any of the offshore wind lease areas, a 51/49 split or something else creative?
A. Our position is House Bill 951 precludes that type of arrangement.
Q. So Duke regulated has to be the sole owner of any project, including any offshore wind sited in international waters?
A. That is our understanding of House Bill 951.
MR. SMITH: Okay. That's all I have.
CHAIR MITCHELL: All right. CCEBA?
MR. BURNS: Thank you, Madam Chair.
CROSS EXAMINATION BY MR. BURNS:
Q. Gentlemen, my name is John Burns. I'm the general counsel of Carolina's Clean Energy Business Association, which I'll refer to as CCEBA, and you'll hear that a lot around here. So it's a pleasure to talk to all four of you today. Most of my questions will be directed to Mr. Nolan, because their directed

at SMRs and new nuclear. That's the topic I intend to cover today.

To the extent any of you other gentlemen have any input, please interject, but let's only talk one at a time for the benefit of the court reporter. All good with that?

Duke anticipates that new nuclear will be an indispensable part of any of its portfolios, doesn't it, Mr. Nolan?

A. (Chris Nolan) That is correct.

Q. There's no portfolio in your Carbon -- in Duke's Carbon Plan that gets to net zero by 2050 without the deployment of new nuclear technology?

A. That is correct.

Q. You go into the differences in your direct testimony, but SMR and advanced reactors are not the same thing in Duke's lexicon; is that right, you're referring to two different things?

A. That is correct.

Q. Can you make a -- can you briefly distinguish between those two?

MS. LINK: And, Mr. Nolan, could you move closer to the mic a bit.

MR. BURNS: Thank you. I should have

said that myself.

Q. Go ahead.

A. Thank you. So small modular reactor typically refers to a size that's 300 to 350 megawatts or less. In the context of clarity and the testimony, when we talk about SMRs, we're talking about light-water reactors.

Q. Okay.

A. Advanced reactors can also be SMRs, but we chose to talk about them as advanced reactors, meaning they're not light-water cooled.

Q. Is that a consistent terminology across the industry or might there be references in the -- in documentation that refer to SMRs and they're actually referring to things like molten salt reactors, that you refer to as advanced reactors?

A. There could be. So there's lots of different titles. There's advanced nuclear, advanced reactors, advanced small modular reactors.

Q. Okay.

A. What we try to do is provide clarity and use SMR for light water and advanced reactor for not light water.

Q. Thank you. I have a few questions about SMRs

first, if you don't mind.
A. Certainly.
Q. How many SMR reactors are included in one plant as modeled for the Carbon Plan?
A. So -- could you restate your -- clarify your question.
Q. My understanding is that one of the benefits of SMRs is that multiple reactors can be placed at one location; inside one building, for instance, that might have more than one reactor in that plant; is that right?
A. So different designs have different attributes. I appreciate the clarification. So if you're talking about a new-scale reactor, all the modules are in the same pool.
Q. Okay.
A. And so they can be either 50 or 77 megawatts. There can be 4, 6, or 12.
Q. In your -- go ahead. Sorry.
A. If you look at the GE BWRX-300, it is a unit that's 285-megawatt electric in a building, and you could put multiple buildings on a site.
Q. And so because Duke has not identified a particular technology or a particular manufacturer that

it wishes to adopt as part of its future plans in North Carolina, you can't tell us whether it will be one 275-watt small modular reactor or, you know, multiple 75-watt small modular reactors in the anticipated units to be brought online in your plant?

A. We have not selected a technology.

Q. Okay. Thank you. According to Figure 6 of the executive summary of the Carbon Plan -- that's on page 14 of the Carbon Plan. I don't know if you have that with you.

A. I do.

Q. I think -- because it's been referred to so many times, I think we can refer to it, and subject to check, but I -- there will be -- new nuclear will not be part of any of the four portfolios proposed by Duke before 2030; is that correct?

A. Before what date?

Q. 2030.

A. I think that's a true statement. I don't know if that's in the Carbon Plan.

Q. Gotcha. Portfolio 3 and Portfolio 4 both bring on 0.3 gigawatts, or 300 megawatts, of new nuclear online by 2034.

Is that consistent with your recollection?

A. They would be online by 2034, correct.
Q. All right. And about 300 megawatts would be one plant?
A. It could be, yes.
Q. Okay. By 2035, is it correct that all four portfolios proposed by Duke would have approximately 600 megawatts of new nuclear?
A. That is correct.
Q. And that can be found in figure 7 for reference for the testimony and for the transcript.
And so based on the math you just did, 600 megawatts would probably be two plants.
A. (No response.)
Q. All right. To be clear, however, at least one of Duke's proposed portfolios would, in fact, reach 70 percent reduction by 2030 in CO2 levels according to Duke's own modeling; isn't that right?
A. That is correct.
Q. And it would do that without any new nuclear plants online of any design?
A. That is correct.
Q. As I understand your testimony and the materials presented in the Carbon Plan, Duke believes that SMRs are the best option for initial investment in

new nuclear; is that right?

A. That is correct.

Q. Meaning the liquid -- the water reactors that you referenced earlier?

A. I think what we're saying is light-water reactors are more similar to the reactors that we operate today.

Q. Okay. And the SMRs -- sorry, please continue.

A. And therefore there is lower technical uncertainty associated with their development and deployment.

Q. Okay.

A. And so for an aggressive schedule and aggressive deployment, we are recommending light-water reactors.

Q. And in layman's terms, it's because the technology is similar to what might be down at the Harris plant but newer and smaller?

A. Correct.

Q. Okay. But you have not yet chosen a design or a manufacturer?

A. That is correct.

Q. Okay. Is it -- is it fair to say that Duke believes that SMR technology will lead to supply chain for small modular reactors?

A. I believe, if you look at the actions of the administration and the funding that DOE is providing and the tax credits that are in the Inflation Reduction Act, that the government is moving in that direction. I think utilities are watching that. So I believe we're seeing a general movement in that direction.

Q. And we've heard this, I think, a few times in the last week and a half, that the IRA will have an effect going forward on the technology being discussed.

Would that apply also to nuclear?

A. There are components that apply to both nuclear in terms of production tax credit, investment tax credit. And if a unit integrated storage, it could potentially qualify for a storage credit as well.

Q. Would it -- would you agree with me that we may not know the full implications of the IRA before 2034? Or let's see, let me rephrase that.

We may not know the full implications of the IRA on nuclear technology before the end of 2033? 2023. I can't talk.

A. I think we're looking to see the guidance that will come out from the Department of Treasury on how to apply those credits to see their value and then roll them in to what our cost estimates will be.

Q. Is one of the advantages that, if we move towards this technology, as you discussed in the administration's course of action, that it may lead to construction of these types of small modular reactors offsite and delivery to your site; is that how it would work?

A. The idea with the small modular reactors is they are standardized design; modular, which means there's more offsite construction. There will be some field construction, but less.

Q. But there's no such supply chain as of yet, is there?

A. One has not been built; that is correct.

Q. There is no factory constructing module -- parts for modular reactors in the United States, is there?

A. I can't make that sweeping statement.

Q. There is no current SMR anywhere in the world that is generating power and providing it for commercial operation, is there?

A. That is correct.

Q. Certainly not one in the United States?

A. That is correct.

Q. And that includes both liquid cooled, small modular reactors, and the advanced reactor technology that you also speak of in your testimony?

A. That is correct. But I would qualify that statement by talking about the advanced demonstration projects that are currently being funded by the Department of Energy that will put a small modular reactor -- an advanced reactor in Wyoming, and an advanced reactor in Washington State before the end of the decade.

Q. Is it a fair comparison to compare that to, sort of, the prototype of a new car model? That it's out there, it works, it drives down the road, but they're not manufacturing 10,000 of those this year?

A. I think it's a very important step. I think it will answer a lot of questions, and something that the rest of the industry can learn from.

Q. Okay. In addition to not having chosen a technology yet, Duke has not identified a site selected for the construction of an SMR plant, has it?

A. That is correct.

Q. In fact, your recommended near-term execution plan seeks authorization to engage in the permitting and site selection process?

A. That is correct.

Q. According to -- I don't know, you don't have the Carbon Plan in front of you, but I understand from Table 4-1 on Chapter 4 of the Carbon Plan, that Duke seeks permission to, quote, begin new nuclear early site permit for one site as part of the Near-Term Execution Plan.

Do you have that in front of you?

A. I do, yes.

Q. Okay. In that -- that's Table 4-1. And in the lower half of that table, on page 5 of Chapter 4, it discusses the proposed resource development options for the 70 percent interim target.

And under new nuclear, to the right, it says "begin new nuclear early site permit ESP for one site," correct?

A. Correct.

Q. So you anticipate an ESP process for one site by 2030?

A. That is correct.

Q. Can you tell me what is included in -- or actually, the second bullet point under that is to begin development activities for first of two SMR

units; is that right?
A. Correct.
Q. Can you tell me what is included in beginning development activities for the first of two SMR units?
A. Certainly. So for an early site permit that is technology neutral, you develop a plant parameter envelope which bounds the technologies of interest. And then you evaluate how many units could fit on that site based on the attributes. And you look at both the environmental and the site safety characteristics of the site.
It's a very important step, in terms of regulatory risk reduction. It addresses environmental issues under NEPA, the National Environmental Protection Act. It also addresses site safety issues like flooding, upstream dam failure, and looks at the seismic suitability. In doing the seismic suitability, you need to have some information about the technologies.
So really the development activities would be to understand the technologies, assess the technologies, and then gain the necessary technical information to support the licensing process.
Q. Does that process include notifying local

governments that Duke proposes to place a nuclear plant in their community?

A. So the NEPA process associated with the early site permit has extensive community engagement.

Q. I understand that the Nuclear Regulatory Commission has amended the emergency zone that might apply to a small modular reactor as opposed to a current technology nuclear plant; is that correct?

A. It's technology specific, but yes, the NRC is looking at the characteristics of the reactor and evaluating the emergency planning zone accordingly. If you look at some of the advanced reactors, if you look at the Natrium, it operates at atmospheric pressure, so there's no real energy to drive a release. If you look at the X-energy, the containment structure is the fuel pedal itself.

So if you look at new scale, it's a totally passive system. They were able to argue successfully that the emergency planning zone should being adjusted to reflect the design.

Q. But there would be an emergency planning zone for any nuclear facility in any community, correct?

A. Yes.

Q. And there would be security issues and other things that the Company must take into account to operate a nuclear plant?

A. Security is part of the requirements for it, right.

Q. Okay. According to the chart on page 32 of your testimony -- I need to get myself there too, if you'll hold on. It's the drawbacks of having one screen versus many pages, so I appreciate your patience. Are you there on page 32?

A. I am, thank you.

Q. Do you see the chart on that page?

A. Table 2, yes.

Q. Table 2 that has new nuclear near-term development activities?

A. That is correct.

Q. Based upon that chart, I understand that initial development activities for the first of two units would cost $17 million between 2022 and 2024?

A. That is correct.

Q. The ESP process in that same chart, which is the permitting process that you discussed --

A. Correct.

Q. -- would cost $55 million between 2022 and 2024, correct?

A. That is what the chart says, correct.

Q. Do you agree with the numbers in that chart?

A. Yes.

Q. Okay. Has Duke already incurred the costs listed under 2022 in this chart?

A. We have not.

Q. Okay. So would you incur those costs between a December 30th order of this Commission and a December 31st end of year?

A. So our goal in developing this chart was to articulate the earliest that the dollars could be spent. We anticipate spending about a million dollars this year.

Q. Okay.

A. But the $5 million is there in case that we get direction from the Commission earlier in the year and would move forward.

Q. If you got indication -- hypothetically, if the Commission were to approve a Near-Term Execution Plan that contained -- that included this -- these procedures, would you -- I guess, would you move the 2022 column over to the right and spend $30 million in 2023; do you know?

A. I think that the dollars would carry forward.

I don't know the exact split between 2023 and 2024.
Q. Is the timeline gonna push another year?
A. I don't think it would push by a year, but no.
Q. In the first -- the first two years for an ESP process with the Nuclear Regulatory Commission for one plant is then a $55 million commitment; is that right?
A. So it's not for a plant, it's for a site.
Q. For one site?
A. And it's for multiple technologies. So for example, just hypothetically, a site is approved for four units. The first two units could be one design, if the technology evolves and another design becomes superior in terms of how it fits into our system. The second, the third, and fourth unit could be a different design. So the ESP has more versatility than a per site application.
Q. So it's per unit or per site?
A. It's per site.
Q. Okay. Thank you for the --
A. I meant per-unit application.
Q. Thank you for the clarification. I appreciate that.

But that $55 million associated with the -- or listed in the chart on page 32 doesn't get you all the way to the NRC permit, itself, does it?

A. No. We estimate that it's -- it's an effort somewhere between 50 and $75 million.

Q. 50 and $75 million per site?

A. Per site.

Q. Okay. You anticipated my next question, thank you. Now I need to skip ahead.

In your testimony on page 31, lines 18 through 22, you testify that the ESP process takes two years with an additional two years for NRC review and approval, correct?

A. Yes.

Q. Is that with every site or with every unit?

A. Site.

Q. One further question about that testimony. You mention on -- you mention in that block, lines 18 through 22, Table L-3 of the Carbon Plan, which is on page 7 of Appendix L, as showing the estimated timeline for development.

For clarity, and I've checked this, do you mean to refer to Figure L-3 on page 12 of Appendix L?

A. That is correct.

Q. Okay. Just for the record, I wanted to make that clarification.

A. Thank you.

Q. Thank you. That timeline shows it is approximately 10 years from vendor path start to beginning fuel load and low-power operation of a unit; is that right?

A. That's a general thumb, yeah.

Q. Okay. I would expect that there would be efficiencies and redundancies built in once Duke has gone through this process with a few permitting processes for a few SMRs; is that right?

A. There would be some efficiencies, yes.

Q. So you might say you'd get better at it?

A. Yes.

Q. But your initial estimate is a timeline of 10 years per -- is that per site or per unit?

A. Per unit.

Q. Okay. Any advanced reactor technology -- go ahead.

A. Let me --

Q. Clarify.

A. Let me correct that. So it would be per license. So the regulatory process would be -- so, for example, let's say that we were just focusing on two units that are mentioned in the Carbon Plan, you would be, one, licensing activity. So you'd ESP one time for multiple sites, an operating license, let's say for two units. And then -- but the construction would be a unit-specific activity.

Q. Did you just say that you would do ESP one time for multiple sites?

A. I'm sorry, multiple units at a site.

Q. Okay.

A. I'll slow down.

Q. No, that's fine, because I'm asking questions in a very haphazard manner, so go ahead.

A. An early site permit is for a site and can be multiple units.

Q. Gotcha.

A. A license has to be for units at a site. It can be multiple units.

Q. Gotcha.

A. So those are singular activities for the application you're looking at. Construction would be a unit-specific activity.

Q. Understood. Any advanced reactor technology would be different from an SMR, right?

A. The technologies are different, correct.
Q. So depending on the technology selected, there would be a new learning curve for Duke and a new learning curve for the NRC for all that permitting process that we just talked about?
A. I think that the NRC is preparing, we'll likely see parallel permitting processes, not from Duke, but from the industry.
Q. Okay. Do you have Appendix E of the Carbon Plan before you?
A. I do not.
MR. BURNS: I might need a copy for the witness. Yes, I have my copy, but not for the witness. Bear with me, Madam Chair. May I approach the witness?
CHAIR MITCHELL: You may.
Q. I'm gonna hand you this document for your review. I'll refer to the page, I think it's already in the record since it was filed. So I don't think I need to introduce that as an exhibit, but if you could take a look at pages 35 and 36 of Appendix E.
A. (Witness peruses document.)
Q. I'm sorry they're not stapled together, but counsel was good enough to give me a copy. So are you

there?
A. Yes.
Q. All right. Now, I understand this is -- relates -- Appendix E relates to quantitative analysis and modeling, and you did not perform the modeling that's represented in Appendix E, did you?
A. That is correct.
Q. But I want to draw your attention to is Table E-3.
A. E-3?
Q. I'm sorry, excuse me, I didn't -- E-39. Thank you. Duke Energy discusses constraints that were placed on the model that limited annual selection of new nuclear units in Table E-39, and total cumulative nuclear units in Table E-40.
Do you see those two tables?
A. Yes.
Q. The total cumulative number of new nuclear units allowed in the model by 2048-plus, on the bottom line there, is 21; is that right?
A. Correct.
Q. That's 21 approximately 300-megawatt nuclear reactors, which is characterized in this chart as 14 SMRs and 7 advanced nuclears; is that right?

A. That is correct.
Q. That's for the modeling.
Does Duke believe that it will be able to site 21 new nuclear reactors in and around North and South Carolina over the next 30 years?
A. To it's -- to meet net zero is a very challenging goal. And if you -- the Nuclear Energy Institute recently sent a letter to the Nuclear Regulatory Commission estimating that nationwide there would need to be 162 new gigawatts of nuclear energy to meet the goal.
Q. Understood.
A. This is what we would need to do to be able to accomplish the goal.
Q. I agree, and I under --
A. And so when we're looking at the sites, we're looking for sites that can handle multiple units.
Q. Does Duke believe that it will be able to site 21 new nuclear reactors in and around North and South Carolina over the next 30 years?
A. Yes.
Q. What risks to that plan has Duke concluded in its analysis and decision to rely to such an extent on those new nuclear?

MS. LINK: Objection. Now we're in modeling. This panel is about --

MR. BURNS: Understood.

MS. LINK: -- the near-term development --

MR. BURNS: I will direct those --

MS. LINK: -- activities.

MR. BURNS: Thank you. That's an effective objection and I'll withdraw my question. But I will reserve the right to ask that to the Modeling Panel on rebuttal.

Q. But you do have knowledge of the risks inherent in the construction and operation of a nuclear plant, don't you?

A. True.

Q. Do you have the knowledge of the risks in siting a nuclear plant?

A. Yes.

Q. Okay. And there are risks to an accelerated plan of multiple nuclear -- bringing multiple nuclear reactors online in a short time frame, aren't there?

A. I think there's a technology risk, and I think the ARDP projects are doing a lot to address those. And so we're looking very closely at first event plans. I think there's regulatory risks. I think that's why we're looking at environmental and siting to make sure we address those. I think there's construction risks.

And so I think the technology risks and the construction risk, in terms of schedule certainty, I think will be resolved after the first number of copies, then I think it becomes a supply chain capacity.

Q. So there's also a supply chain risk.

There'd be a risk with fuel supply risk too, would there not?

A. I think that is a risk that the Department of Energy is addressing.

Q. You mention in your testimony that Duke is an investor in the Natrium project, correct?

A. No, we're not an investor. We're part of the project.

Q. Part of the project.

Natrium is a molten-salt fast reactor; is that right?

A. It's a liquid sodium.

Q. Liquid sodium. Thank you. And it uses -- you address in your testimony that it uses HALEU fuel?

A. Yes.
Q. How do you pronounce -- is there a -- is it HALEU?
A. So it's an acronym, it's HALEU. It's high-assay low-enrichment uranium.
Q. It's true, isn't it, that the most ready source of that fuel, HALEU, is Russia currently?
A. That is correct.
Q. Duke anticipates, though, that it will be able to overcome the risk of -- well, let me rephrase this.
The Ukraine war has placed a restriction on the supply of HALEU fuel, has it not?
A. So I'll answer the question that I think you're asking, which is capacity challenges for HALEU.
So the Inflation Reduction Act included $700 million for DOE to pursue that -- the domestic source.
Q. Okay.
A. If you look at the current enrichment facilities, the technology is the same, you're just increasing enrichment. So it becomes a capacity issue.
And so one of the ways the DOE is addressing the capacity issue is to put a procurement in place to

put a buy order in that will cause these enrichment facilities to increase their capacity and go through the licensing process, which is a high enrichment typically security requirement exchange. So we believe that that challenge is being resolved.

Q. And Duke anticipates that it will be able to overcome those risks, right?

A. Correct.

Q. Duke's experience in nuclear -- highly trained staff and employees and its leadership in nuclear technology makes it particularly suited to achieve this ambitious timeline; is that your testimony?

A. That is correct.

Q. So when Duke wants to get something done, it can get it done, right?

MS. LINK: Objection. I just think it's a statement, but --

MR. BURNS: Just asking if he agreed with the statement in cross.

CHAIR MITCHELL: All right. I'm gonna sustain the objection. Be more specific with your question.

Q. And generally speaking -- I'll pursue a different question.

Generally speaking, which risk is Duke more able to overcome, one where the variables are within its control or one based upon facts not within its control?

A. I believe one of the reasons that we're focusing on an early site permit is because those are within our control. And I believe we're recommending that we monitor the ones that are not in our control.

Q. Okay. But the effect of the war on Ukraine on supply of nuclear fuel is not within Duke's control, is it? Of HALEU fuel.

A. I -- so two different questions. Is it fuel or HALEU?

Q. HALEU.

A. It's not in our control.

Q. But transmission constraints in its own balancing areas is likely to be something that Duke can overcome?

A. So I'm not here to testify for transmission, although transmission is an important part of siting.

Q. Okay. Duke's position is that it should be a second entrant into this new nuclear market; is that right?

A. I believe we've laid out a process for the Commission to manage risks and focus on siting while the technology develops as a prudent course.

Q. Your testimony and the testimony of your panel is that it would be prudent for Duke to be sort of an early adopter in the initial round of reactor projects once the test projects are complete; is that right?

MS. LINK: Objection. I don't -- I would ask counsel to point where in the testimony it talks about being an early adopter.

Q. Have I fairly characterized your testimony there, sir.

A. I believe that you used the statement second mover, and I believe that's a fair characterization.

Q. Thank you. That's a fair answer. Thank you.

Did you calcu- -- is there a calculation of the levelized cost of the energy anticipated in the Carbon Plan to be produced by new nuclear, or would that be a question best addressed at the modeling?

A. The modeling team.

Q. Do you, as a person with experience in nuclear energy, expect costs associated with the deployment of new nuclear technology to increase or decrease in the next 15 years?

A. So are you talking about the cost to operate the existing fleet or costs to construct the plants?

Q. Cost to construct plants.

A. Cost to construct plants typically follows a patten where they increase and then decrease.

Q. And how long do they increase, typically?

A. We have not gone through a cycle in recent times for me to make a projection.

Q. And no one's gone through a cycle for the construction of an SMR; is that right?

A. That is correct.

Q. No further questions at this time. Thank you.

CHAIR MITCHELL: All right. We'll start with CIGFUR. We'll break for lunch at 12:45.

CROSS EXAMINATION BY MS. CRESS:

Q. Good afternoon, gentlemen. My name is Christina Cress, counsel for CIGFUR. I have the coveted spot right before lunch. I don't think I will get through my questions, but I will try my best. And these questions are gonna be directed to the panel as a whole, so anybody, please, just chime in if you are the most appropriate person to answer the question.

Duke's projected cost and rate impact estimates provided for the Carbon Plan do not include costs associated with Duke's plans to pursue 20-year subsequent license renewals of existing nuclear resources; is that right?

A. (Chris Nolan) That is correct.

Q. How much does Duke expect these SLRs to cost?

A. So a subsequent license renewal application is a licensing process that provides the option to operate an additional 20 years. We expect them to cost between 45 and $50 million per site.

Q. What is the basis for that cost estimate?

A. The basis for the cost estimate is really what we saw during the initial license renewal phase. Our process is similar, and so therefore we think those estimates are pretty reasonable.

Q. Are you aware that Virginia Electric & Power Company, doing business as Dominion Energy Virginia, recently pursued regulatory approval for these SLRs for its Surry Units 1 and 2 and North Anna Units 1 and 2?

A. I am.

MS. CRESS: At this time, I'd like to introduce an exhibit, and it's this pile right here. And I'll request permission from the Chair to identify -- to mark this exhibit as CIGFUR II and III Long Lead-Time Panel Direct Cross Examination Exhibit Number 1, which is a copy of Dominion's recent petition of Virginia Electric & Power Company for approval of a rate adjustment clause designated rider SNA in Case Number PUR2021 to 29.

CHAIR MITCHELL: All right. The document will be marked as CIGFUR II and III Long Lead-Time Panel Direct Cross Examination Exhibit 1.

(CIGFUR II and III Long Lead-Time Panel Direct Cross Examination Exhibit Number 1 was marked for identification.)

Q. Gentlemen, I'm gonna direct your attention to the top of page 2 of the pleading, itself, which is the ninth page of the document.

A. (Witness peruses document.)

(Regis Repko) I apologize, page 9?

Q. So it will say page 2 at the bottom of the pleading, but it will be the ninth page of the document.

Now that you have this in front of you, can you please confirm that the current cost projection for the SLRs of these four Dominion Energy Virginia SLRs is currently projected to cost up to $3.9 billion?

MS. LINK: Your Honor -- I mean, Chair Mitchell, I would object. She's asked if he can confirm something that -- a piece of paper that's been put in front of his -- him on the witness stand. He can read the document, but I don't believe he has any information that he could confirm the cost estimate.

MS. CRESS: Chair Mitchell, I'm happy to restate the question and simply ask the witness to read what the document says into the --

CHAIR MITCHELL: All right. I'll sustain the objection. Ask your question that way.

MS. CRESS: Thank you.

Q. So please, if you would, instead turn to the previous page, and we'll start at the bottom of that page. There's a sentence that begins with the word "specifically." If you could please read that complete sentence into the record.

A. (Chris Nolan) "Specifically, the Company seeks a determination that it is reasonable and prudent for the Company to pursue the nuclear license, extensions, and related projects, which a current cost projection of $3.9 billion, and approve of cost recovery through rider SNA for phase 1 of the program, which includes those investments to date and for the following three calendar years, 2022 through 2024, totalling approximately $1.2 billion. In support" -- so am I done?

Q. Yes. Thank you. That was the end of the sentence, thanks. And if you could, please turn to what will be shown as page 4, but it's really the 11th page of the document.

Do you see where under Section 3B there's a section titled "Capital Upgrade Component"?

A. Correct.

Q. Okay. Can you please read paragraph 8 into the record.

A. "In order to maintain the safety, reliability, and efficiency of the Surry and North Anna units up to 80 years of operation, the Company has identified 33 capital upgrade component projects that must be undertaken in addition to the SLRAs. The Company created an extensive screening process in determining whether project was necessary and eligible for the capital upgrade component of the SLR."

Q. Has Duke determined whether capital upgrades will be necessary for the pursuit of SLRs for its existing nuclear fleet?

A. So we invest in our fleet to maintain its safety and reliability. And we make improvements, changes, component replacements based on aging and degradation as part of our capital budget. And that capital budget is -- the viability of the plan is evaluated in the IRP periodically by the Commission. And so the SLR provides an option for continued operation.

It is not an option -- it is not an attempt to gain additional capital dollars for the maintenance of the plant.

I think Dominion is -- has a different approach, and if you look at it, it talked about the SLRs and upgrade projects. And so I think our estimates for SLR would be the same, they're just including a lot of projects.

Q. It's possible, is it not, that the Nuclear Regulatory Commission could conditionally grant SLRs to Duke Energy and require that the Company undertake certain capital upgrade costs as part of the SLRs?

A. So typically, component degradation is something that's managed under the current operating license, and we're required to maintain safety on a daily basis. The subsequent license renewal looks at age and management, so it typically looks at concrete, buried cable, and do you have the appropriate surveillance programs in place to manage aging.

So there typically are requirements in the license, but they're monitoring programs, they're not capital upgrades. Capital upgrades would be required under the existing license.

Q. And so I believe you answered that question on, you know, what happens on a typical basis, what happens usually. My question is, is it possible that the NRC could conditionally grant these SLRs contingent upon the Company making certain capital upgrades to the nuclear fleet?

A. So I'm not in a position to say how the NRC would use its authority. I've not seen that.

Q. So as you sit here today, have the Companies definitively determined whether or not capital upgrades would be necessary in conjunction with pursuit of these SLRs?

A. I think -- I think what I tried to state in my testimony is that we look at the material condition of the plan and maintain it in accordance with using the annual capital budget. We have not looked specifically at the license renew period, but don't expect it to be any different than what we see on a day-to-day basis now.

Q. Okay. Thank you. Switching gears. It is --

CHAIR MITCHELL: Mr. Nolan, make sure you're in your mic, sir.

THE WITNESS: Thank you.

Q. It's possible for any of the Long Lead-Time resources included in Duke's proposed Carbon Plan, that project development activities may not ultimately result in generation plant that is placed into service; is that correct?

A. That is possible.

Q. And how will ratepayers be protected against the risk that Long Lead-Time project development activities may not result in new generation plant that becomes used and useful in the provision of electric service?

A. So I think what we're asking for in the Carbon Plan is for the Commission to approve the decision to expend resources. But any recovery of resources would be in a future proceeding. I think exploring these options to look at the timing that they could be available and in the best path to provide a low-cost option for the customer or valuable, some paths may prove successful, some paths may prove not. And the Commission will do a prudency review.

A. (Regis Repko) If I might add just a broader view. So as we propose here, there's a very specific set of development activities proposed for the Commission's decisions. To your question, so we can progress down a path on time frame, a very limited time frame and actions. The Companies support caps relative to those costs. And then a third strategy, again, holistically is not to be a first mover, to be a second mover.

We already have a Bad Creek 1 facility, so we've demonstrated its construction and operation. SMRs, again, we expect we will be a second mover. Along those lines, we already have Companies that are out in front with signed contracts and direction relative to SMRs. Offshore wind, a number of projects from the Northeast on down the Atlantic that will be able to learn from and gain from those efficiencies.

Q. Thank you for that. And would your answer be the same, gentlemen, if we're talking about how would ratepayers be protected from the risk of stranded assets?

A. (Chris Nolan) So one of the things we're asking for is an early site permit. I think an early site permit has value on its issuance. It's approved for 20 years, it can be renewed up to additional 20 years, it's technology neutral. And we've demonstrated in the Carbon Plan that it's not a -- it's not if, but when.

And so I think that asset has value to the customer. And I only spoke to that one specifically because it's what's in the scope of this panel.

Q. Thank you.

MS. CRESS: Looking at the time, do I need to --

CHAIR MITCHELL: Yeah, we'll go ahead and break now.

MS. CRESS: Thank you, Chair Mitchell.

CHAIR MITCHELL: All right. Let's go off the record. We'll be back on at 1:45.

(The hearing was adjourned at 12:46 p.m. and set to reconvene at 1:45 p.m. on Tuesday, September 20, 2022.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF WAKE)

I, Joann Bunze, RPR, the officer before whom the foregoing hearing was conducted, do hereby certify that any witnesses whose testimony may appear in the foregoing hearing were duly sworn; that the foregoing proceedings were taken by me to the best of my ability and thereafter reduced to typewritten format under my direction; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this hearing was taken, and further that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 23rd day of September, 2022.

JOANN BUNZE, RPR
Notary Public #200707300112