PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Monday, September 26, 2022

TIME: 1:29 p.m. - 4:50 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: 25

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

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

EXHIBITS

P R O C E E D I N G S

CHAIR MITCHELL: All right. Let's go back on the record, please. We will continue. We actually have several more questions from Commissioners before we turn it over to the parties. So, Commissioner Duffley.

Whereupon,

TYLER FITCH,

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

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. Good afternoon. So I just have one more question, and it's on page 46. And it's going back to the least cost resource planning.

And on pages -- on line 7 of page 46, you mention that keeping units past their economic retirement dates could cost the ratepayers -- that's not a confidential number, correct?

A. No, no, that's --

Q. Okay. The $1.4 billion.

And I just wanted to know, how is that $1.4 billion calculated, please?

A. Good afternoon. And thank you for the question. The $1.4 billion are what are called fixed operations and maintenance expenses, or capital investment. So those are costs that the utility, in this case Duke, incurs just to keep this unit online. It has nothing to do with how much it might cost -- there might be wear and tear on the unit from running it or fuel costs. Those are not included here. This is just -- when we're talk about fixed O&M and capital -- and ongoing capital investment, that's simply what it costs to keep this unit available to run. And what we used to calculate that value was a Sergent & Lundy study conducted, I believe, for the U.S. Energy Information Administration that took, sort of, a statistical approach to these O&M costs, and how is the coal fleet of the United States, in general, done, and what can we reasonably expect, in terms of fixed O&M costs, based on, sort of, historical actual incurred expenses.

So there's, sort of, a formula that comes out of that report that has to do with the technology that's used at the plant and its age, and we plug that in to get, sort of, a cost per kilowatt per year, and then we simply sum those for the years after the, sort of, earliest practicable date that those units were running. I'm not sure how clarifying that was, but there you go.

Q. It was -- it's exactly what I needed, so thank you for that.

CHAIR MITCHELL: All right.

Commissioner McKissick?

EXAMINATION BY COMMISSIONER McKISSICK:

Q. And this is just a follow-up on Commissioner Duffley's question. So while you projected that would be the savings, there would also be costs incurred for providing energy during that time frame.

So, I mean, it hasn't been netted out, has it? Or, you know, if I'm understanding your response correctly to Commissioner Duffley's question.

A. Sure. Right. Well, that's true, it doesn't include the cost of producing the -- or producing the energy. And there would be capital costs for whatever other unit happened to be online or happened to be replacing it.

Q. So the true net savings aren't projected, just the totality of projected saved expenses?

A. Well, I think what I would say is this also doesn't include the costs of whatever energy that unit would produce and the variable operations and maintenance costs and fuel costs that are associated with it. And I think, generally speaking, studies in the industry show that, in terms of just the costs of producing energy from a coal unit is quite high.

And so if we did include, you know, those net energy costs, I would expect to see that, you know, replacement -- like, our replacement resource would produce at a lower variable, sort of, cost-per-megawatt hour anyway.

The reason that's hard to do one-to-one is because we're looking at a portfolio instead of a single unit replacement, that type of thing.

Q. Thank you. That clarifies things.

CHAIR MITCHELL: All right. We will take questions on Commissioners' questions.

EXAMINATION BY MS. FORCE:

Q. Okay. Good afternoon, Mr. Fitch. My name is Margaret Force with the Attorney General's Office, and I just have a quick follow-up on questions that you had from Commissioner Brown-Bland and Commissioner McKissick having to do with the initial difficulties that you ran into running the model and inferences that might be drawn from that. It's a pretty specific question.

Do you recall, when you were running the initial models, if there was an issue that came up about the timing of outages for nuclear units and how that was done in the Duke modeling?

A. I don't want to rule that issue out, but it's not -- it's not specifically coming to mind for me right now.

Q. Well, let me ask it this way.

Maybe I'm misunderstanding, but was it the case that the initial modeling was having all of the nuclear units go out on outages at the same time?

MR. BREITSCHWERDT: Chair Mitchell, Commissioner Brown-Bland didn't ask anything about nuclear units or specific challenges that Mr. Fitch had that related to nuclear units in any way, and this was not raised in his response. So if this is, essentially, a fishing expedition that the AGO's expert would like to speak to, I'm sure you can ask him this question and he can provide insights into it.

MS. FORCE: We can do that. This is one of the inferences that can be drawn about some of the difficulties that was faced -- were faced in modeling. So I'm drawing it right from the questions.

CHAIR MITCHELL: All right. Ms. Force, just ask the last question and then move on if you don't --

MS. FORCE: Yeah, that's my only question.

CHAIR MITCHELL: Okay.

Q. If you recall, there was an issue initially about the whether the timing of the outages that was modeled had all of the nuclear units going out on outages at the same time, rather than spreading those out?

A. The issues that we had originally included one file, which -- which had an issue with corruption in its upload or download that caused either an error to occur or for really the results to be -- to, sort of, not make sense, to put it in plain speak. Specifically to the nuclear outage convergence, I don't have a strong recollection of that issue.

Q. That's okay. I appreciate it. No other questions.

CHAIR MITCHELL: All right. CIGFUR?

MS. CRESS: Thank you, Chair Mitchell.

EXAMINATION BY MS. CRESS:

Q. Good afternoon again, Mr. Fitch. You mentioned in response to a question from one of the Commissioners, you brought up the concept of leakages associated with carbon offsets.

Can you elaborate on that concept?

A. Absolutely. And this proceeding actually has a great example of a potential leakage, which was originally when Duke Energy was contemplating siting gas generation in South Carolina, that would -- would not technically, perhaps, count towards HB 951, and -- but would potentially be part of the Carbon Plan. And, essentially, what that -- that is a perfect encapsulation of what leakage is. So the idea is, any reduction in carbon emissions from North Carolina would just simply be offset by an increase in emissions in South Carolina.

So what we would say is that those emissions leaked and, for that reason, the, sort of, carbon governance, that regime that we're looking at, wouldn't be as effective.

Q. Thank you. And likewise, REGI came up in your responses to certain questions from the Commissioners.

Are you aware that studies have shown that approximately 25 percent of apparent emissions reductions in REGI jurisdictions are leaked to surrounding states?

A. I'm not familiar with any study that found that.

Q. Okay. Are you familiar with CIGFUR witness Muller's testimony filed in this docket?

A. Not in detail.

Q. Okay. Would you agree with me that several Commissioners asked you questions about EE and DSM measures and how those are recovered in rates?

A. We had a very high-level conversation about that, yes.

Q. Would you agree, subject to check, that CIGFUR witness Muller testified, among other things, that his Company, Charlotte Pipe and Foundry, is in the process of investing hundreds of millions of non-utility dollars to decommission a foundry currently reliant on fossil fuel melt processes and instead converting to a more efficient and cleaner electric mill process?

MS. THOMPSON: Objection. Chair Mitchell, I don't believe this -- this is getting far afield from any questions.

CHAIR MITCHELL: I'll sustain it.

MS. THOMPSON: I think a very thin read --

CHAIR MITCHELL: I'll sustain it. Go ahead.

Q. You were asked by some Commissioners about EE/DSM and the modeling levels percentages of retail sales; do you recall that?

A. I do.

Q. If there was some way that Duke could get credit for energy efficiency measures that otherwise would show up as naturally occurring, but which are actually happening at a cost to the private sector, what would you think about that?

A. To a degree, that is a difficult thing to integrate into the EnCompass modeling. That was, sort of, the foundation of my testimony. Yeah, I think without a deeper dive into the cost recovery mechanism, I don't feel like I could give a substantial answer on that.

Q. Okay. Would you agree that, if Duke had an emergency load reduction program allowing industrial customers with flexible load to participate on an interruptible rate, would that provide benefits to the system?

MR. BREITSCHWERDT: Chair Mitchell, I'd object again. Again, that this is a fishing expedition that has no relationship to any Commissioner questions in any specific tangible way.

CHAIR MITCHELL: I'll sustain. Just make sure your questions are tailored to Commissioners' questions. If we have to go here, I'll ask you guys to recite the specific question asked by the Commissioner that you're following up on. So let's not have to do that so we can get through this more quickly. But just keep your questions to -- limited to Commissioners' questions.

MS. CRESS: Understood. And nothing further. Thank you.

EXAMINATION BY MS. GRUNDMANN:

Q. Good afternoon. I wanted to follow up. Commissioner Duffley, I believe, asked you some questions about, sort of, regional cooperation, RTOs, imbalance markets.

Do you recall those questions?

A. I do.

Q. Do you think that those concepts could provide benefits to ratepayers in the context of the least-cost mandate of the Carbon Plan?

A. Completely agree with that.

Q. Do you think it would be helpful if the Commission were to order the Company to study those various options as part of its 2024 Carbon Plan?

A. I think they should be studied. I think that there could be issues with who does the studying. I think there is -- I think the Commission has -- essentially, I think it should be -- it's a topic that is ripe for study and I think could deliver benefits to ratepayers. And I think I would look to the Commission for the best way to implement that.

Q. Thank you. Those are all the questions I have.

CHAIR MITCHELL: Go ahead, Public Staff.

EXAMINATION BY MS. LUHR:

Q. Nadia Luhr with the Public Staff.

So you stated, in response to a question from a Commissioner McKissick. That you're modeling included the firm point-to-point transmission cost adder, so the wheeling charge, for Midwest onshore wind; is that right?

A. That's right.

Q. Okay. And I think you also stated that the transmission cost adder included the costs of the upgrades that would be necessary on the transmission system to import the energy from the Midwest into Duke's system; is that what you said?

A. My understanding is that that PJM firm point-to-point includes the -- essentially, the, like, levelized cost of upgrades on the PJM system.

Q. Okay. So it would include -- it would include any upgrades needed to the transmission system plus the wheeling charges?

A. That's my understanding, yeah.

Q. Okay. That's all I have.

CHAIR MITCHELL: Duke?

MR. BREITSCHWERDT: No questions.

CHAIR MITCHELL: Ms. Thompson?

MS. THOMPSON: Thank you, Chair Mitchell, just a few.

EXAMINATION BY MS. THOMPSON:

Q. Mr. Fitch, Commissioner Brown-Bland asked you a question regarding the inference or deduction that the Commission should -- that you would hope the Commission would draw from the Synapse team's difficulties running the EnCompass model due to some technical flaws in the files that were produced; do you recall that?

A. I do.

Q. Should the Commission give any more weight to Duke's proposed portfolios than to those put forward by any other intervenor in this case?

A. I don't think so.

Q. And do you have confidence in Synapse's modeling results?

A. I do.

Q. Commissioner McKissick asked you about your experience with EnCompass, and I believe you said you had -- that started in 2021 when you joined Synapse; do you recall that?

A. I do.

Q. How many years -- collectively, how many years of experience do you and your team members who were involved in producing the carbon-free by 2050 report and doing the EnCompass modeling, how many years of collective experience do those folks have with running EnCompass?

A. So the team that worked directly on this project was myself, John Tabernero, and

Divita Bhandari, and I think -- my rough estimate is that, collectively, we have 8 -- 8 to 10 years of experience over dozens of projects.

Q. Okay. Thank you. And let's see. Commissioner McKissick asked you about -- he asked you a quite broad question about the differences between the assumptions that Synapse made and the assumptions that Duke made.

You mentioned energy efficiency as one example; do you recall that?

A. I do.

Q. Overall, what can you say about what resources Duke's assumptions tended to favor, just directionally speaking, and what types of resources did they tend to disadvantage?

A. That's a good question. I think, generally speaking, I would say I think they were favorable assumptions for the gas-fired units, given -- especially assumptions about how these units might be operated in the later part of this planning period. Just -- I mean, just as an example, a unit with 35-year lifetime is brought on in 2029, its projected retirement date would be 2064.

And so making assumptions about whether this unit -- or what the latter half of this unit's life is, that suggests something will come along and save it, that seems aggressive to me. And I would say, on the SMR side, I think there's a relatively -- or there's a fairly aggressive capital cost and construction time assumptions that I think -- yeah, are quite optimistic. So those two stand out to me as potential ones that have -- that are -- that have optimistic assumptions applied to them.

And I think we've talked about, in this hearing, some resources like solar deployment issues or even energy efficiency targets that caused those to play less of a role than they could.

Q. Commissioner McKissick also asked you about your Table 6 which is the table showing the recommended -- Synapse-recommended near-term actions; do you recall that?

A. I do.

Q. And you discuss a number of resources. You kind of went down the table and discussed the resources in there.

What resources were not in your Table 6?

A. There were no gas-fired assets.

Q. Okay. And finally, quickly on the typical week structure, do you believe that using the typical week structure caused the Synapse modeling to lose important precision?

A. No, I don't.

Q. And do you believe that the typical week structure accurately simulates the real-world operation of the system?

A. I do.

Q. Thank you. No further questions.

MS. THOMPSON: Thank you, Chair Mitchell. I need to make a motion.

CHAIR MITCHELL: Yes, I'll take motions.

MS. THOMPSON: I would move Mr. Fitch's Exhibit 1 into the record. I would also move SACE, et al. Fitch Redirect Exhibits -- Redirect Examination Exhibits 1 and 2 into the record. And out of an abundance of caution, I would also move to have the report entitled "Carbon-Free by 2050, Pathways to Achieving North Carolina's Power Sector Carbon Requirements at Least Cost to Ratepayers," which was accompanied by verification by Mr. Fitch and attached to the comments filed jointly by SACE, et al. and NCSEA July 20, 2022, entered into evidence at the appropriate time.

CHAIR MITCHELL: Hearing no objection, motion is allowed.

(Exhibit TF-1; SASE, et al. Fitch Redirect Examination Exhibits 1 and 2, and SACE, et al. and NCSEA's Carbon-Free by 2050, Pathways to Achieving North Carolina's Power Sector Carbon Requirements at Least Cost to Ratepayers were admitted into evidence.)

CHAIR MITCHELL: And take care to work with the court reporter to ensure that the confidential portions of testimony and the report are so identified in the transcript.

MS. THOMPSON: Yes. Thank you, Chair Mitchell.

CHAIR MITCHELL: All right. Any additional motions?

(No response.)

CHAIR MITCHELL: All right. With that, you may step down. Thank you very much.

THE WITNESS: Thank you, Chair Mitchell.

CHAIR MITCHELL: All right. Tech Customers, you may call your witnesses.

MR. SCHAUER: Thank you, Chair Mitchell.

CHAIR MITCHELL: Do you-all have a preference between being sworn or affirming?

Whereupon,

MICHAEL BORGATTI, ADRIAN KIMBROUGH, AND MARIA ROUMPANI,

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

CHAIR MITCHELL: All right. Mr. Schauer.

MR. SCHAUER: Thank you, Chair Mitchell.

DIRECT EXAMINATION BY MR. SCHAUER:

Q. Craig Schauer for Tech Customers. At this time already seated at the stand are Michael Borgatti, Maria Roumpani, and Adrian Kimbrough.

Mr. Borgatti, please state your name and business address for the record.

A. (Michael Borgatti) My name is Michael Borgatti. My business address is 417 Denison Street, Highland Park, New Jersey.

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

A. So I'm the vice president of RTO services and regulatory affairs for an energy and utility consultancy called Gabel Associates. I manage a multi-disciplinary team of folks that serve as the principal point of contact for our clients that are transacting in wholesale services throughout North America.

Q. And can you provide a brief overview of your job responsibilities that are relevant to your testimony?

A. Yeah, absolutely. So I've been directly involved on behalf of our clients in the development, construction, financing, operations, and ownership of literally tens of thousands of megawatts of natural gas-fired facilities. I've also been involved in the development, ownership, and operation of onshore and offshore wind facilities, solar facilities, batteries. We also advise buyers at wholesale and advise folks that are looking to develop transmission solutions, particularly for public policies like the ones at issue in this proceeding.

Q. And have you testified before this Commission previously?

A. No.

Q. Did you cause to be filed in this proceeding on September 2, 2022, direct testimony consisting of 33 pages and 2 exhibits?

A. Yes.

Q. Do you have any corrections to your testimony?
A. No.
Q. If I asked you the questions in this prefiled submission today, would your answer be the same?
A. Yes.
Q. Mr. Borgatti, did Gabel Associates caused to be filed in this docket on July 15, 2022, a report titled "Review of the Carbon Plan" -- I'm sorry, "Review of the Duke Carbon Plan," and presentation of a preferred portfolio consisting of 66 pages?
A. Yes.
Q. And is that commonly referred to as the Gabel report?
A. Yes.
Q. And is the Gabel report true and accurate to the best of your knowledge?
A. Yes.
Q. And did Gabel Associates cause to be filed a confidential and public version of the Gabel report?
A. We did.
Q. Dr. Roumpani, please state your name and business address for the record.
A. (Maria Roumpani) My name is Maria Roumpani.

Strategen's business address is 1020 -- 10265 Rockingham Drive, Sacramento.

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

A. I work with Strategen Consulting. I'm a senior manager. And while at Strategen, I focus on resource planning, reviewing integrated resource plans, and leading a lot of the modeling work that we conduct as a company.

Q. And can you provide a brief overview of your job responsibilities that are relevant to your testimony?

A. Yes. So I have reviewed, on behalf of some of our clients, several integrated resource plans across the U.S., and I have conducted alternative modeling for some of them.

Q. And have you testified before this Commission previously?

A. No, I have not.

Q. Did you cause to be filed in this proceeding on September 2, 2022, direct testimony consisting of 22 pages?

A. Yes.

Q. Do you have any corrections to your

testimony?

A. No, I do not.

Q. If I asked you the questions in your prefiled submission today, would your answers be the same?

A. Yes.

Q. Mr. Kimbrough, can you please state your name and business address for the record.

A. (Adrian Kimbrough) Yes. My name is Adrian Kimbrough. Business address is 417 Denison Street, Highland Park, New Jersey.

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

A. Also employed by Gabel Associates as a vice president as well.

Q. All right. And can you provide a brief description of your job responsibilities that are relevant to your testimony?

A. Sure. So I work on cost of service rate filings, asset valuations, and production cost modeling. And in that -- in that regard, I've reviewed the cost structures, capital costs of hundreds of power plants, including the very same class of gas generators at issue in this proceeding. So we have quite a bit of insight with respect to the actual costs for operating in plants in development of these types of projects throughout the U.S.

Q. And have you testified before this Commission previously?

A. I have not.

Q. All right. And did you cause to be filed in this proceeding on September 2, 2022, both confidential and public versions of your direct testimony consisting of 14 pages?

A. Yes.

Q. Do you have any corrections to your testimony?

A. No.

Q. If I asked you the questions in your prefiled submission today, would your answers be the same?

A. They would.

MR. SCHAUER: Chair Mitchell, at this time, we would move that the direct testimonies of Mr. Borgatti, Ms. Roumpani, and Mr. Kimbrough be copied into the record as if given orally from the stand, and that the exhibits of Mr. Borgatti be marked for identification.

CHAIR MITCHELL: Motion is allowed.

(Exhibits MB-1 and MB-2 was identified

as it was marked when prefiled.)

(Whereupon, the prefiled direct testimony of Michael Borgatti, prefiled direct testimony of Adrian Kimbrough, and prefiled direct testimony of Maria Roumpani 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

In the Matter of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan	))))	DIRECT TESTIMONY AND EXHIBITS OF MICHAEL BORGATTI ON BEHALF OF TECH CUSTOMERS

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 179

Direct Testimony and Exhibits of Michael Borgatti

On Behalf of Tech Customers

September 2, 2022

Q. PLEASE STATE YOUR NAME, TITLE, AND ADDRESS.

A. My name is Michael Borgatti and I am presently employed as a Vice President at Gabel Associates, Inc., an energy, environmental, and public utility consulting firm. My business address is 417 Denison Street, Highland Park, New Jersey, 08904.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS DIRECT TESTIMONY?

A. I am submitting this Direct Testimony on behalf of the Tech Customers (Apple Inc., Google LLC, and Meta Platforms, Inc.).

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. My formal education includes a B.A. in Biology from the University of Colorado and a *juris doctor* from Rutgers University School of Law.

I manage a multi-disciplinary team of energy industry professionals. My team and I serve as the primary subject matter experts for our firm's clients participating in the wholesale market and non-market regions throughout North America. We actively support multiple clients in PJM and other ISO/RTO markets, including the New York ISO, New England ISO, Mid-Continent ISO, Electric Reliability Council of Texas, and Southwest Power Pool. Our clients include Investor-Owned Utilities, Independent Power Producers, renewable and thermal generation owner-operators, financial institutions, commodity trading operations, institutional investors, and end-use customers.

I have subject matter expertise in the rules governing wholesale power systems' planning, processes, operations, and market administration functions. My firm monitors the constantly evolving regulations in the energy sector, and we advise our clients' how these constructs impact their assets and investments and provide our outlook for the regions in which they participate. We also produce investment-grade analyses and forecasts of resource adequacy needs, wholesale power prices, and other market fundamentals. I regularly advise clients on factors that impact the valuation of utility-scale renewable and thermal generation assets and energy storage resources. I also support clients' engagement with state utility commissions and the Federal Energy Regulatory Commission ("FERC").

Q. HAVE YOU TESTIFIED IN REGULATORY PROCEEDINGS PREVIOUSLY?

A. Yes, I have testified before the Federal Energy Regulatory Commission ("FERC") and the New Jersey Board of Public Utilities. I have also supported testimony and expert analysis before the West Virginia Public Service Commission and Ohio Public Utility Commission.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. My testimony responds to the direct testimony of Snider, et al., submitted on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, the "Companies" or "Duke") in support of their proposed Carbon Plan. I respond to their criticisms of the Gabel/Strategen Report, including their allegations that our analysis was constructed to achieve a predetermined outcome and failed to consider regional transmission needs. I also address their presumption that natural gas-fired generation without firm transportation is imminently necessary for winter reliability and identify potentially material flaws in their Loss of Load Expectation ("LOLE") evaluation of our Preferred Portfolio.

More generally, I explain how the Preferred Portfolio put forward by the Tech Customers presents a superior generation mix that best balances the competing objectives of compliance with the statutory carbon goals, ensuring the grid's reliability, and protecting ratepayers from needless or unwarranted costs.

MODELING & ASSUMPTIONS: OVERVIEW OF GABEL REPORT

Q. DID GABEL PREPARE A REPORT WITH ITS OWN PROPOSED PORTFOLIO ON BEHALF OF THE TECH CUSTOMERS?

A. Yes. Working with modeling support from Strategen and using the same EnCompass capacity expansion modeling software used by Duke, together with the model inputs provided by Duke, Gabel conducted various analyses, which we describe fully in the report filed with the Commission on July 15, 2022, in this docket. Based on this analysis, the Gabel/Strategen Report presents an EnCompass-driven "Preferred Portfolio" that leverages proven decarbonization strategies to achieve the state's emissions reduction goal by 2030 at lower cost and risk to customers than the Companies' proposed Carbon Plan.

Q. WHERE DID GABEL START IN CREATING ITS OWN PORTFOLIOS?

A. Our analysis focuses on Duke's Portfolio 1 as a point of comparison to the Preferred Portfolio described in our report, because it is the only scenario that achieves the state's carbon emissions reduction target by 2030. Then, using the Preferred Portfolio as our base model, we also ran alternative runs that account for different sensitivities, which corroborate the validity of the recommendations from our report, which the Preferred Portfolio reflects.

Q. COULD YOU SUMMARIZE THE "PREFERRED PORTFOLIO" THAT RESULTED FROM THE MODELING WORK DONE BY GABEL AND STRATEGEN?

A. Yes, as a result of our modeling efforts we were able to establish the viability of a "Preferred Portfolio" which yields a preferred outcome as compared to Duke's proposed portfolio. The Preferred Portfolio is characterized by: (1) a significant expansion of solar and battery storage with recommendations to mitigate interconnection and transmission limitations; (2) enlarged investment in energy efficiency, resulting in significant savings for ratepayers by reducing system costs; (3) robust investment in behind-the-meter (BTM) distributed generation; (4) retirement of coal resources by 2030; (5) utilization of existing natural gas plants that can be contracted to avoid the construction of new units and the risk of stranded assets; and (6) following a no-regrets approach that preserves optionality.

The Preferred Portfolio shows that immediate new natural gas is not only not necessary, but a portfolio without combined cycle resources can lower both the Net Present Value of the Revenue Requirement (NPVRR) and emissions compared to Duke's proposed P1 portfolio, which is the only Duke portfolio that achieves the state's energy policy objective. Although the Preferred Portfolio includes a combustion turbine in December 2029, Strategen's work shows that this is the result of a model limit on the annual deployment of energy storage resources. Specifically, the model is internally constrained to allow selection of only up to 30 batteries (per Duke's original assumptions). Given this constraint, had the model been allowed to select more batteries—a constraint that the Companies lift for their supplemental modeling—it is very possible that no new gas generation would be included at all.

The resource additions selected by the Preferred Portfolio is summarized in the table below.

Resource additions in the preferred portfolio (MW)

Preferred	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036-2040	2041-2045	by 2050
CT J	-	-	-	376	-	-	-	-	-	-	-	-	-
CT J H2	-	-	-	-	-	-	-	-	-	-	-	1,503	7,516
2x1 CCJ	-	-	-	-	-	-	-	-	-	-	-	-	-
2x1 CCF	-	-	-	-	-	-	-	-	-	-	-	-	-
SMR	-	-	-	-	-	-	-	-	-	-	-	285	-
Adv. Reactor w/ Int. Storage	-	-	-	-	-	-	-	-	-	-	1,380	2,415	690
Onshore Wind	-	600	600	-	-	-	-	-	-	-	450	-	-
Offshore Wind (2029)	-	-	-	-	-	-	-	-	-	-	-	-	-
Standalone Solar	-	-	-	-	150	-	-	-	-	-	-	-	-
S+S 25% Battery Ratio, 4hrs	-	150	750	-	-	-	-	-	-	-	-	-	-
S+S 50% Battery Ratio, 2hrs	-	-	-	-	-	150	600	-	-	-	-	-	-
S+S 50% Battery Ratio, 4hrs	-	450	2,100	1,200	600	750	825	1,800	1,800	1,800	5,554	3,511	2,687
4-hr Battery	-	450	900	1,500	-	-	-	-	-	-	-	450	-
6-hr Battery	-	-	50	-	-	-	-	-	-	-	150	2,000	650
8-hr Battery	-	-	-	-	-	-	-	-	-	-	-	-	-
Bad Creek II	-	-	-	-	-	-	1,680	-	-	-	-	-	-

The Preferred Portfolio is discussed in detail in the Report submitted on behalf of the Tech Customers in this docket on July 15, 2022.

Q. CAN YOU DESCRIBE SOME KEY DIFFERENCES BETWEEN THE PREFERRED PORTFOLIO RECOMMENDED BY GABEL AND DUKE'S PROPOSED PLAN?

A. Our strategy prioritizes near-term investment in infrastructure necessary for any carbon plan, including each of the Companies' portfolios, while avoiding or delaying investments that may not be needed or are reliant on speculative or unproven technology. In other words, our plan places a premium on achievable, actionable measures that are least-cost and help to satisfy the overall statutory objectives. As part of this recommendation, we focus on elements of the highest short-term impact, such establishing a comprehensive, regionally developed transmission plan (with new investments in transmission), new renewable generation resources and battery storage, and greater emphasis on energy efficiency and behind-the-meter generation.

In contrast to Duke's models, the Preferred Portfolio maximizes the cost efficiencies, reliability value, and lower risk profile of existing thermal generation before developing new gas-fired generation. This strategy provides flexibility to calibrate the Companies' resource mix through future IRP proceedings in response to dynamic considerations like maturing technologies, changing reliability needs, and access to firm fuel supply.

We also leverage alternative interconnection processes to accelerate the deployment of renewable and battery storage resources at the sites of the Companies' deactivating coal plants and existing thermal-generation assets. This strategy reduces the interconnection costs for new clean technologies and unlocks access to tax incentives and low-cost financing opportunities from the Inflation Reduction Act ("IRA"). This approach also reduces pressure on the conventional generator interconnection queue, representing a significant challenge to achieving the state's carbon reduction goals.

Other aspects of our plan, like greater investment in energy efficiency and BTM distributed generation, also reduce emissions without relying on the conventional generator interconnection process. IRA creates new incentives for these resources too.

Taken together, the Preferred Portfolio performs better than Duke's proposed P1 (which, as stated, was our point of departure) for the same compliance date in both costs and emissions, while providing the Commission with a no-regrets approach that preserves full optionality to account for future developments.

Q. HAVING REVIEWED DUKE'S CRITICISMS OF THE MODELING ASSUMPTIONS UNDERLYING THE PREFERRED PORTFOLIO, DOES GABEL CONTINUE TO ENDORSE THE FINDINGS OF ITS REPORT?

A. Yes. The Preferred Portfolio presents a reasoned, balanced, and measured approach to setting on a least-cost path to fulfilling the carbon reduction targets established by the North Carolina General Assembly. It preserves optionality over the long term, focuses on the achievable tactics that can be employed in the near term, avoids short-term commitments that could lead to "regrets," and does all this for less cost than Duke's proposal.

Moreover, since the filing of Duke's Direct Testimony, we have carefully reviewed Duke's various criticisms of our report, and we have conducted further analyses that give us even more comfort that our model presents a preferred approach to carbon reduction.[1]

Additionally, I would note that the recent passage into law of the IRA, which of course our report had not accounted for, further amplifies and energizes many of our recommendations, particularly those concerning the use of deactivating coal sites and existing thermal generators for new renewable and

[1] These analyses are described more fully in the Direct Testimony of Dr. Maria Roumpani of Strategen, submitted on behalf of Tech Customers.

energy storage resources. It also significantly increases the incentives for energy efficiency deployment, which features prominently in our analysis.

Notably, the IRA does not offer similar incentives for new gas-fired generation. While the IRA's incentives for green hydrogen could provide value in the future, it is not commercially viable today. Our recommendations accentuate the value that the IRA provides. Approving investment in new gas-fired generation now could squander the IRA's value to ratepayers, particularly considering our finding that the Commission can revisit a need for these assets in a future proceeding.

Therefore, Gabel remains committed to its recommendation that the Commission should not select new gas generation in the near term and that it should wait—at least until the next Carbon Plan proceeding—to evaluate whether such resources are necessary to accomplish the least-cost, reliable pathway to achieve North Carolina's carbon goals.

MODELING & ASSUMPTIONS: OVERVIEW OF CONCERNS WITH DUKE'S CARBON PLAN MODELING ASSUMPTIONS

Q. BASED ON YOUR REVIEW OF DUKE'S CARBON PLAN AND ITS PROPOSED PORTFOLIOS, HAS GABEL IDENTIFIED ANY CHALLENGES WITH THE COMPANIES' CARBON PLAN?

A. Yes. We have identified several challenges with the implementation of Duke's proposed plan. I understand and appreciate that any projection into the future involves uncertainties. Still, given the magnitude and importance of this planning effort – which promises to be transformative in nature – coupled with the concrete legislatively-mandated goals, it is essential that the plan be achievable and grounded in, at a minimum, near-term known and measurable data.

Q. WHAT ARE SOME OF THE SPECIFIC CHALLENGES WITH DUKE'S PLAN THAT YOU HAVE OBSERVED?

A. First, as Dr. Roumpani describes in her testimony, the Duke analysis included several out-of-model steps that are a deviation from typical resource planning analysis, as well as model choices that limit the model's ability to select the least cost portfolio. Collectively, these factors tend to bias the Companies' results toward selecting new gas-fired generation resources instead of zero-carbon renewable resources.

Second, the Companies' proposed Carbon Plan accelerates investment in gas-fired generation and in speculative technologies, like SMR, that are not currently available. The modeling done for Gabel by Strategen shows that new gas generation is not needed in the near term, allowing the Commission to defer a decision on investment in these resources to a future proceeding. The Companies' analysis shows a steep decline in the capacity factor for the NGCC resources, exposing ratepayers to the risk of stranded assets.[2] While SMRs may ultimately feature in the Companies' long-term resource mix, they are unavailable today. They may not become viable or provide the least-cost solution to meet the state's energy needs.

Third, the Companies rely (almost exclusively) on the conventional generator interconnection process to install the new resources that the Carbon Plan requires within the state. This strategy creates a single point of failure, where achieving the carbon reduction target by 2030 hinges on exponentially increasing the number of interconnection requests the Companies complete annually. For example, the Carbon Plan assumes that the Companies will install about 2.5 times more than the highest amount of new solar generation ever deployed in the state. In contrast to Duke, we strongly recommend that the Commission avoid placing too much stress on the interconnection process by adopting a plan that includes diversified pathways to market for renewable and energy storage resources—which our model does. Our report recommends developing a comprehensive transmission expansion and interconnection plan that leverages experience from other regions, rather than being dependent on Duke alone.

[2] *See* Gabel Report, at 10.

Q. DID YOUR ANALYSIS SOLVE FOR A SPECIFIC PORTFOLIO OR RESOURCE MIX?

A. No. Our modeling effort did not solve for a particular portfolio or have any bias against "firm, dispatchable resources" as the Companies allege.[3] As conveyed to Gabel, the Tech Customers' goal was to explore whether there was an alternative model that was compliant with the state's carbon goals, was least-cost, satisfied reliability requirements, and was reasonably achievable. We succeeded in creating a portfolio that satisfied these baseline objectives.

Q. WAS YOUR ANALYSIS BIASED TO FAVOR RENEWABLE RESOURCES OVER THERMAL GENERATION?

A. No, as evidenced by the fact that the Preferred Portfolio includes new gas generation and expanding contracts with existing gas assets. However, we disagree with Duke on the necessary level of investment in new gas-fired generation because our EnCompass modeling confirms that other more cost-effective solutions are available.

The additional sensitivities that Dr. Roumpani discusses in her testimony—for example, to adjust our assumptions for EE and to limit the availability of gas PPAs—support the Tech Customers' confidence that the Companies can achieve the 70% carbon reduction goal by 2030 with other non-carbon-emitting sources. The results of these sensitivities confirm one of the key findings from our report:

[3] Direct Testimony of Snider, et al., at 185.

new gas-fired generation is not necessary at this time and may not be needed in the future.

Our analysis also shows that any potential need for new gas generation does not arise until at least December 2029. This additional time allows the Commission to defer a decision on investment in new gas-fired resources to a future IRP process and approve an equivalent investment in transmission, renewable resources, and battery storage here. These necessary components of any Carbon Plan are far less likely to become stranded investments than new gas-fired generation and SMR nuclear. Avoiding an immediate investment in new gas resources allows the Commission to take a significant step toward achieving the state's carbon reduction goals at less cost and risk than the Companies' Carbon Plan. It also provides flexibility to recalibrate the resource mix as future system needs dictate.

MODELING & ASSUMPTIONS: AVAILABILITY OF GAS PPAs

Q. HOW DO YOU RESPOND TO DUKE'S CONTENTION THAT YOUR PORTFOLIO DOES NOT PROVE THE AVAILABILITY OF EXISTING THIRD-PARTY GAS RESOURCES?

A. I disagree. First, our portfolio included the extension and expansion of existing power purchase agreements with thermal generators that are operational today. Our analysis accounted for existing contractual expiration dates. To be conservative, we apply an adder to the proxy contract price in our EnCompass model to reflect a potential premium that the Companies may have to pay to acquire firm supply from these resources.

In addition, out of an abundance of caution, and in response to Duke's criticism, Dr. Roumpani modeled a scenario that assumed just one of the three PPAs in the Preferred Portfolio was available to the Companies. The results confirm our original finding that new gas-fired generation was not needed until at least December 2029. This sensitivity also achieved the state's carbon reduction goal by 2030 at less cost than Duke's proposed Portfolio 1.

Taking a step back, it's essential to recognize that our report does not recommend acquiring these *specific* PPA resources. We only demonstrate that they are available, cost-effective, and help defer a need for any new gas generation that could become stranded assets.

RELIABILITY: GAS GENERATION

Q. HOW DO YOU RESPOND TO THE COMPANIES' ASSERTION THAT NEW GAS-FIRED GENERATION IS ESSENTIAL FOR RELIABILITY?

A. While gas-fired generation can provide important resource firming characteristics, it is not, *per se,* reliable. In 2021 NERC concluded that "growing reliance on natural gas creates the potential for common-mode failures that could have widespread reliability impacts."[4] In 2022, NERC concluded that interdependencies between the electric and gas systems "are a major new reliability risk that must be explicitly managed."[5] This conclusion is particularly relevant in this proceeding, because according to Astrape's Effective Load Carrying Capability ("ELCC") Study, essentially all of the Companies' reliability risk occurs in winter, where gas risks are heightened.[6]

Q. WHAT ARE THE POTENTIAL RELIABILITY RISKS ASSOCIATED WITH THE NEW GAS-FIRED GENERATORS THAT THE COMPANIES SEEK APPROVAL TO DEVELOP IN THIS PROCEEDING?

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[4] NERC, *2021 ERO Reliability Risk Priorities Report* (Aug. 2021), at 33, *available at* https://www.nerc.com/comm/RISC/Documents/RISC%20ERO%20Priorities%20Report_Final_RISC_Approved_July_8_2021_Board_Submitted_Copy.pdf.

[5] NERC, *2022 State of Reliability Report* (July 2022), at vi. (hereafter "2022 NERC SOR"), *available at* https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2022.pdf.

[6] Duke Carbon Plan, Attach. III, at 25.

A. Fuel delivery risk is a primary concern. Natural gas fuel delivery issues were responsible for over 27% of generator outages, derates, and failures during the notorious February 2021 cold weather event.[7] The "risk of fuel delivery curtailment is elevated for the many natural gas generators that do not contract for firm natural gas transportation."[8]

The Companies themselves acknowledge insufficient firm transportation available to support their existing NGCC fleet,[9] let alone the new gas generators they propose to procure in this proceeding. We agree with their caution that "without additional interstate pipeline firm transportation, the Companies have increased fuel assurance risk, increased customer fuel cost exposure."[10] Adding significantly more new NGCC and NGCT resources without available firm fuel supply only increases these risks. It supports our recommendation that the Commission defer a decision to invest in new gas generation until these risks can be thoroughly evaluated and managed.

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[7] FERC, NERC & Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 16, 2021) *available at* https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and

[7] 2022 NERC SOR, at 45.

[8] 2022 NERC SOR at 45.

[9] Duke Carbon Plan, App. N, at 7.

[10] Id., at 9.

RELIABILITY: DUKE'S CRITICISM OF THE PREFERRED PORTFOLIO

Q. PLEASE SUMMARIZE DUKE'S WITNESSES CLAIM THAT THE TECH CUSTOMERS' PREFERRED PORTFOLIO DID NOT PASS A SERVM RELIABILITY STUDY.

A. Near the end of their pre-filed direct testimony, Companies' witnesses Snider, et al., claim that SERVM modeling of the Preferred Portfolio did not satisfy their Loss of Load Expectation ("LOLE") criterion. SERVM is a proprietary software model that Duke is using—outside of EnCompass—to "stress test" for transmission and generation resources proposed by intervenors to determine whether the system can meet peak demand after accounting for variables like generator forced outages and load forecast error.

As the Commission is aware from its prior consideration of reserve margin in various IRP proceedings, the industry standard minimum LOLE requires a utility to carry enough reserves to avoid shedding firm load no more than one day every ten years. Resource adequacy studies typically express this incremental reserve requirement through a Planning Reserve Margin ("PRM") multiplier to forecast peak load. For example, if an LOLE model like SERVM determines that a 10% PRM is necessary for reliability, the system will require 11 MW of firm supply for every 10 MW of peak demand. While this methodology is generally viewed as an industry standard practice for resource adequacy planning purposes, the reliability value of a given resource portfolio is highly dependent on the variables input into the LOLE model.

Q. HAVE YOU IDENTIFIED ANY POTENTIAL CONCERNS WITH THE COMPANIES' SERVM ANALYSIS AS DUKE IS SEEKING TO APPLY IT TO THE PREFERRED PORTFOLIO IN THIS PROCEEDING?

A. Yes. In 2020, the Companies retained Astrapé to perform a resource adequacy study for the region using SERVM. Astrapé recommended that the Companies use a 17% PRM for the region based on their LOLE studies that include non-firm imports from neighboring areas. However, it does not appear that the Companies used the same system configuration as Astrapé to evaluate their proposed portfolios or the Tech Customers' Preferred Portfolio.

Instead, per Duke's explanation of how it applied SERVM to its modeling, "the SERVM model was used to rerun the 17% reserve margin Combined Case, except as an island with no market assistance."[11] This change—to assume the Preferred Portfolio is an island with no market assistance—is likely to materially impact their results. Snider, et. al., indicate that this same system configuration was used in evaluating our portfolio. If our understanding of their modeling is correct, using an LOLE criteria based on a scenario that does not reflect likely future system conditions raises questions about the accuracy of these findings.

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[11] Id., App. E, at 64.

While we do not have access to SERVM to verify their analysis, Astrapé's 2020 reserve studies include "islanded" sensitivities that indicate the order magnitude impact of this assumption. These scenarios assume that the utilities must maintain reliability individually without support from neighboring regions. Astrapé found that DEP and DEC would require PRMs of 25.5% and 22.5% to operate reliably in island mode and satisfy the 0.1 LOLE standard illustrating the potential significance of this change.[12] Multiplying these PRM values by the forecast winter peak load in 2030 could increase the Companies' reserve requirement by over 2,300 MW, as shown in the table below.

Region	2030 Winter Peak Load[13]	Astrapé 17% Reserve Margin	Islanded Reserve Margin[14 15]	Internal Capacity Requirement
Formula	*a*	*b = a * 1.17*	*c*	*d = a * (1+c)*
DEP	17,976	21,032	25.5%	22,560
DEC	14,431	16,884	22.5%	17,678
Total	**32,407**	**37,916**		**40,238**
Delta				**2,322**

Astrapé also found that adding imports to each island case significantly reduces the Companies' internal resource requirement, as expected based on their analysis. Excluding imports from these cases could increase the internal resource requirement by about 2,060 MW, as shown in the table below.

[12] Id.
[13] Id., App. E, at 20.
[14] Id., Attach. II, at 6
[15] Id., Attach. I, at 6

Region	2030 Winter Peak Load	Reserve Margin Island Mode Only	Reserve Margin Island Mode w/ Imports	Delta	Island Mode Only Internal Resource Req.	Island Mode w/ Imports Internal Resource Req.	Delta
Formula	*A*	*b*	*c*	*d = b - c*	*e = a * (1+b)*	*f = a * (1+c)*	*g = e - f*
DEP	17,976	25.50%	19.30%	6.20%	22,560	21,445	1,115
DEC	14,431	22.50%	16.00%	6.50%	17,678	16,740	938
						Delta	**2,053**

Without access to SERVM, we cannot verify whether these simplified calculations match the Companies' assumptions. However, Astrapé's resource adequacy studies suggest that the Companies' decision to evaluate the Preferred Portfolio using reliability criteria that do not reflect likely system conditions could have materially skewed their results.

Q. ARE THERE ANY OTHER POTENTIAL ISSUES WITH THE COMPANIES' SERVM ANALYSIS?

A. Yes. Flexible, dispatchable resources are necessary components of any reliable resource mix. The Companies rely heavily on NGCC and NGCTs as the sources of these grid services. However, NERC recognizes that stand-alone battery storage (SAS) and dispatchable solar plus storage (SPS) hybrids can also mitigate energy shortfall when conventional renewable sources are curtailed.[16]

The Preferred Portfolio adopts NERC's view by shifting nearly 6 GWs of stand-alone utility-scale solar generation to SPS resources compared to Portfolio 1

[16] NERC, *2021 Long-Term Reliability Assessment* (Dec. 2021), at 29, *available at* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf.

by 2030. It also adds 700 MW more four-hour SAS than Portfolio 1 over the same period. However, the Companies appear to have configured their SERVM model using a fixed dispatch profile for the SAS and SPS resources that could dramatically reduce the reliability benefits these resources provide.

According to the Companies' response to AGO Data Request No. 3-6, the storage portion of the hybrid was modeled using a fixed operating profile instead of being freely available to operators under economic dispatch.[17] This profile assumes that the battery would charge using solar energy that the SPS would otherwise lose when its inverter converts DC to AC voltage before sending energy to the grid. Next, the Companies dispatched the battery according to the Companies' hourly avoidable cost rates. As Dr. Roumpani explains, the Companies forced this dispatch profile into Encompass rather than allowing Encompass to select the optimal dispatch profile. Allowing Encompass to optimize the battery portion of the hybrids demonstrably impacts the model's results. After several intervenors, including Public Staff, North Carolina's Attorney General Office, Tech Customers, and others raised this issue, the Companies corrected their modeling approach when modeling the supplemental portfolios. They also acknowledged that these resources performed better due to the change.

[17] *See* Duke's Response to AGO DR No. 3-6 (Exhibit MB-1).

Q. WHAT ARE THE PROBLEMS WITH USING A FIXED DISPATCH PROFILE FOR THE STORAGE PORTION OF THE SPS RESOURCES IN THE PREFERRED PORTFOLIO?

A. This decision prevents batteries from optimizing their state of charge based on reliability needs and system energy costs. The Companies' responses to AGO Data Request No. 3-6 and NCSEA, et al., Joint Data Request No. 2-12 indicate that the Companies may have used the fixed operating profile in their LOLE study of the Preferred Portfolio.[18] Astrapé's ELCC study from the Companies' 2020 IRP proceeding confirms using a fixed operating profile would materially understate the reliability value of the battery portion of the SPS resources that are available for operator control in the Preferred Portfolio. Astrapé concludes that it is "imperative for the utility to have control of these resources as battery penetrations increase",[19] which our Preferred Portfolio allows. For portfolios like ours with high levels of storage, Astrapé found that it is expected that the capacity values in the higher battery penetration cases with fixed dispatch are unreasonably low.[20] The study recommends basing the capacity values of both SAS and the battery portion of dispatchable SPS resources based on an economic dispatch profile. It appears that

[18] *See* Duke's Response to AGO DR No. 3-6 (Exhibit MB-1); Duke's Response to NCSEA, et al., DR No. 2-12 (Exhibit MB-2).

[19] *E.g.*, Duke Energy Carolinas 2020 IRP, N.C.U.C. Docket No. E-100, Sub 165 (Sept. 1, 2020), Attach. IV (Atrape Consulting, *Duke Energy Carolinas and Duke Energy Progress Storage Effective Load Carrying Capability (ELCC) Study* (Sept, 2020)) at 9, available at https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=aa5afc15-1414-4b85-a49e-ccbdf71a947f.

[20] *Id.* at 13.

the Companies' reliability analysis of the Preferred Portfolio may use a fixed operating profile, which would dramatically impact their findings.

Q. WHAT CAN YOU CONCLUDE ABOUT DUKE'S RELIABILITY ANALYSIS AS APPLIED TO THE PREFERRED PORTFOLIO?

A. I do not believe that their reliability analysis substantiates their alleged reliability issues. Given our lack of access to the SERVM model, further analysis is necessary to confirm whether the Companies based their reliability analysis on a reasonable view of the portfolio's operational performance and system conditions during peak demand. However, I have serious concerns that their SERVM analysis relies on the same flawed assumptions that they applied in EnCompass, which would materially understate the value of the Preferred Portfolio. Additionally, Dr. Roumpani shows that, even if you assume the validity of Duke's reliability assessment, any potential reliability issue is easily addressed without compromising the integrity of the Preferred Portfolio by extending the closing date for the Belews Creek coal facility.

TRANSMISSION: RENEWABLE IMPORTS

Q. HOW DOES DUKE CONCLUDE THAT RENEWABLE IMPORTS ARE COST PROHIBITIVE?

A. According to the Direct Testimony of Roberts and Farver, the Companies' view is based on an estimate of the cost of transmission upgrades and firm transmission service for a 1,500 MW transfer from PJM to DEP.[21] Based on their assessment of this single PJM interface with DEP, they conclude all renewable imports would be cost-prohibitive.

Q. IS THIS ASSUMPTION REASONABLE?

A. No. The analysis assumes that all renewable imports would only occur across this lone PJM interface with DEP—they do not consider any other neighboring interfaces with the Companies. A cost estimate for a single interface is not a proxy for all potential interfaces with adjacent balancing authorities. The need for upgrades and transmission service fees will differ depending on system conditions between the specific source and sink points of the firm P2P reservation.

The table below compares PJM's border rate to neighboring regions' firm transmission reservation fees, and it reveals a wide variety of transmission fees. This comparison shows that applying PJM's border rate uniformly to all neighboring areas overstates the cost of firm transmission service by up to 43%.

[21] Direct Testimony of Roberts and Farver, at 59.

Firm P2P Rates ($/MW-yr)	PJM	TVA	SoCo	SEPA (MISO)	DOM SC	Santee Cooper
Total	67,625	38,256	45,822	58,890	63,911	41,571
Discount to PJM Border Rate		-43%	-32%	-13%	-5%	-39%

Transmission costs are not the same for all interfaces, and the transmission study from PJM to DEP does not reflect the costs associated with all other interfaces. Duke's analysis of a lone interface between PJM and DEP does not prove that all renewable imports are cost prohibitive. Moreover, exploring opportunities to join an RTO or ISO like PJM would eliminate these charges.

TRANSMISSION: COAL RETIREMENT

Q. IS DUKE ACCURATE IN ALLEGING[22] THAT YOUR ANALYSIS DOES NOT CONSIDER TRANSMISSION NEEDS DRIVEN BY COAL RETIREMENTS?

A. No. We address these transmission challenges with various recommendations in our report.

First, we point out that coal retirements present both a challenge for transmission and an opportunity. We recommend that the Commission direct the Companies to maximize the opportunity to site new generation technologies at the deactivating coal unit sites through Generator Replacement Requests and prioritize these sites for additions of renewable and storage resources. The Companies fail to

[22] *See* Direct Testimony of Snider, et al., at 54.

acknowledge our recommendation in their testimony. Nevertheless, I note that the Companies likewise conclude that deploying new generation resources at these coal sites may negate the need for some of these upgrades.[23]

In addition, our report recommends that the Companies engage in a comprehensive transmission and generator interconnection planning process with the North Carolina Transmission Planning Collaborative ("NCTPC"). This process would naturally build on the transmission planning analysis in the Companies Carbon Plan.

COST: INFLATION REDUCTION ACT

Q. DOES THE INFLATION REDUCTION ACT ("IRA") IMPACT YOUR ANALYSIS?

A. Yes. The IRA significantly amplifies the value of the core recommendations from our report. It extends existing Investment Tax Credits ("ITC") and Production Tax Credits ("PTC") for solar and wind resources. It also makes stand-alone storage eligible for an ITC equal to or upwards of 30% of the capital costs. Solar and solar plus storage would qualify for the ITC or a new PTC that could significantly improve the economics for the hybrid resources that feature prominently in our analysis. Notably, the value of these credits declines over time, increasing the value

[23] Duke Carbon Plan, Attach. P, at 15.

to consumers by accelerating the deployment of these resources instead of new gas-fired generation.

The IRA also provides new funding opportunities, including federally guaranteed loans and other incentives for developing new carbon-free technologies at the sites of deactivating coal assets. We recommend that the Companies prioritize using these sites for renewables and storage, which could provide a meaningful opportunity to combine the benefits of these funding sources with ITC and PTC credits.

We also recommend exploring Surplus Interconnection Service to deploy storage and clean technologies at the companies' existing thermal generator sites. As noted in our report, adding energy storage to existing gas-fired assets can dramatically reduce the generator's emissions profile. Thanks to the IRA, if the Companies apply for financing with the Department of Energy and receive approval, the costs of Surplus Interconnection Service could be offset by federal financial incentives that further increase the value potential for ratepayers.

<u>CONCLUSION</u>

Q. DO YOU HAVE ANY CONCLUDING OBSERVATIONS?

A. Yes. Any plan that the Commission approves will require substantial investment in transmission, distribution, and generation resources to achieve the carbon reduction mandate while maintaining reliability. Our analysis demonstrates that the

Commission can take meaningful steps towards achieving the state's carbon reduction goals by approving initial investments in existing proven technologies and strategies such as solar, storage, on-shore wind, and Grid Edge demand reduction – together with transmission upgrades – instead of approving immediate expenditures on new gas-fired generation and SMRs.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

In the Matter of		
Duke Energy Progress, LLC, and	)	DIRECT TESTIMONY OF
Duke Energy Carolinas, LLC, 2022	)	ADRIAN J. KIMBROUGH
Biennial Integrated Resource Plans	)	ON BEHALF OF
and Carbon Plan	)	TECH CUSTOMERS

Q. PLEASE STATE YOUR NAME, TITLE, AND ADDRESS.

A. My name is Adrian J. Kimbrough. I am a Vice President at Gabel Associates, Inc., ("Gabel Associates") an energy, environmental, and public utility consulting firm. My business address is 417 Denison Street, Highland Park, NJ 08904.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. My formal education includes a B.A. in Political Science from the University of California, Berkeley, and an M.B.A. with concentrations in finance and economics from the Harvard Business School. My professional background includes roles as an Energy Industry Analyst with the Federal Energy Regulatory Commission ("FERC" or the "Commission") and as a Cryptologic Linguist with the United States Marine Corps.

Q. HAVE YOU TESTIFIED PREVIOUSLY IN REGULATORY PROCEEDINGS?

A. Yes. I have provided expert testimony to regulatory commissions including FERC and the Virginia State Corporation Commission in my current role as a Vice President with Gabel Associates, as well as in my prior role as an Energy Industry Analyst with FERC. Topics addressed cover a range of subject matters, including, but not limited to, cost-of-service ratemaking for electric utilities and oil pipelines, economic damages analyses, stranded cost analyses, and renewable portfolio standard policy and economic impact analyses.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS DIRECT TESTIMONY?

A. I am submitting this Direct Testimony on behalf of the Tech Customers (Apple Inc., Google LLC, and Meta Platforms, Inc.).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to the direct testimony of Snider et al., submitted on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, the "Companies" or "Duke"), addressing the reasonableness of resource capital cost assumptions underlying the Duke Energy Carbon Plan ("Carbon Plan").

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR DIRECT TESTIMONY?

A. No.

<u>COST: CAPITAL COST ASSUMPTIONS</u>

Q. IN THE SNIDER, ET AL. TESTIMONY, DUKE ALLEGES THAT INTERVENOR RESOURCE CAPITAL COST ASSUMPTIONS UTILIZED IN SUPPORT OF THE GABEL REPORT AN "OUTCOME-ORIENTED" APPROACH. IS THIS ACCURATE?

A. No. "Outcome oriented" implies that certain benchmarks were excluded or manipulated to create the appearance of capital costs that support a specific narrative. This characterization is not accurate. To the contrary, it is apparent that Duke's modeling relies on unrepresentative resource cost assumptions, and these inaccurate assumptions create the false impression that gas-fired generators are more cost-competitive than renewable generators.

Q. WHAT HAVE YOU REVIEWED IN CONDUCTING YOUR ANALYSIS?

A. For purposes of this analysis, I reviewed resource cost estimates from the following sources in addition to those included in the Carbon Plan:

1. U.S. Energy Information Administration ("EIA")[1]
2. International Energy Agency ("IEA")[2]
3. National Renewable Energy Laboratory ("NREL")[3]

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[1] *See* U.S. Energy Information Administration, *2022 Annual Energy Outlook, Table 55: Overnight Capital Costs for New Electricity Generating Plants, accessed at* https://www.eia.gov/outlooks/aeo/. Note that the referenced cost data is expressed in 2021 dollars terms. To convert the cost totals to 2022 dollars, I escalated the values using the U.S. Bureau of Labor Statistics' Consumer Price Index for All Urban Consumers ("CPI-U"), accessed at https://data.bls.gov/timeseries/CUUR0000SA0?years_option=all_years .

[2] *See* International Energy Agency, *Levelised Cost of Electricity Calculator, accessed at* https://www.iea.org/data-and-statistics/data-tools/levelised-cost-of-electricity-calculator. Note that the referenced cost data is expressed in 2018 dollars terms. To convert the cost totals to 2022 dollars, I escalated the values using the CPI-U.

[3] See U.S. National Renewable Energy Laboratory, *2022 Annual Technology Baseline (ATB) Cost and Performance Data for Electricity Generation Technologies, accessed at* https://data.openei.org/submissions/5716. Note that the referenced cost data is expressed in 2021 dollars terms. To convert the cost totals to 2022 dollars, I escalated the values using the CPI-U.

4. Lazard[4]
5. The Brattle Group ("Brattle")[5]

To ensure consistency in the cost data I reviewed, I compared the EIA's 2022 overnight capital costs estimates for comparable resource types, measured all costs using the same base year values, and included all available estimates regardless of any potential impact on skewing the final results (i.e., showing resource costs as either higher or lower than they would otherwise be if more data were included).

Q. WHAT DOES YOUR ANALYSIS SHOW?

A. As shown in the following tables, Duke's cost assumptions for new resources are out of line with market benchmarks, on average:

[BEGIN CONFIDENTIAL]

[redacted]

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[4] See Lazard, *Levelized Cost Of Energy and Levelized Cost Of Storage* (Oct. 28, 2021), *accessed at* https://www.lazard.com/perspective/levelized-cost-of-energy-levelized-cost-of-storage-and-levelized-cost-of-hydrogen/. Note that the referenced cost data is expressed in 2021 dollars terms. To convert the cost totals to 2022 dollars, I escalated the values using the CPI-U.

[5] See The Brattle Group, *PJM CONE 2026/2027 Report* (Apr. 21, 2022), *accessed at* https://www.pjm.com/-/media/library/reports-notices/special-reports/2022/20220422-brattle-final-cone-report.ashx.

[redacted]

[redacted]

[redacted]

Q. [redacted]

A. [redacted][6] [redacted]

[redacted][7]

[redacted]:

[redacted]

[6] *See* Direct Testimony of Snider, et al., at 192–93.
[7] *See id.*, at 150:15-19

[redacted][8]

[redacted]

[END CONFIDENTIAL]

While these cost discrepancies vary between resource types, the data above clearly show that Duke's cost assumptions are out of line with market expectations and that the Duke plan advantages gas-fired generators at the expense of renewable-powered generators.

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[8] *See* EIA, *2022 Annual Energy Outlook, Renewable Fuels Module* (Mar. 2022), accessed at https://www.eia.gov/outlooks/aeo/assumptions/pdf/renewable.pdf. (emphasis added) (citations omitted).

Q. IN THE SNIDER, ET AL. TESTIMONY, DUKE ALLEGES THAT INTERVENORS "OVERSTATED THE CAPITAL COSTS OF NEW CC AND CT RESOURCES." IS THIS ACCURATE?

A. No. As explained above, Gabel reviewed cost data from multiple publicly available sources and compared these data to the Duke cost estimates. The data clearly show that Duke's cost estimates for new NGCC and NGCT resources are grossly understated. In fact, of the myriad benchmarks we reviewed, only two countries from the IEA report indicated a lower build cost for NGCC or NGCT resources: Italy and Mexico. This is to be expected, however, given that countries with lower labor costs[9] and input costs[10] show lower overall build costs than those from countries with higher costs such as the U.S. Regardless of these minor global differences, however, the U.S. along with every other Organisation for Economic Co-operation and Development ("OECD") country included in the IEA report—as well as every other benchmark we reviewed—indicated higher costs for these resources than those provided by Duke in the Carbon Plan.

Q. IN THE SNIDER TESTIMONY, DUKE ALLEGES THAT THE GABEL REPORT SUBMITTED BY TECH CUSTOMERS DOES NOT REFLECT "ACTUAL UNIT CONFIGURATIONS AND OPERATING CONDITIONS." IS THIS ACCURATE?

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[9] *See* Organisation for Economic Co-operation and Development, Unit Labour Costs, *accessed at* https://data.oecd.org/lprdty/unit-labour-costs.htm.

[10] *See* Organisation for Economic Co-operation and Development, Price Level Indices, *accessed at* https://data.oecd.org/price/price-level-indices.htm.

A. No. As explained above, Gabel reviewed data from multiple publicly available resources for *representative* configurations and operating conditions. Duke, on the other hand, relies on unsupported claims that the hypothetical gas-fired generators it proposes to build will be cheaper than the market benchmarks outlined above, based on its assumption that Duke will be able to realize cost savings by building plants with more generating units:

> The CT costs generated by EIA AEO are based on a single unit F-Class CT and do not account for economies of scale savings from building multiple CT units on a single site. Large utilities would not build a site with a single unit CT due to the savings that can be observed building multiple CTs on a single site. Consistent with past IRPs, Duke Energy's CT costs are based on a typical 4-unit CT site.[11]

While it may be reasonable to assume that plants with more units may be cheaper on a dollar per kilowatt ("$/kW") basis than plants with fewer units due to economies of scale, plants with more generating units are not "typical," contrary to Duke's assertion.

To evaluate how common multi-unit CTs are, Gabel reviewed EIA's current database of operating generators in the U.S.[12] Of the nearly 223 CT units installed across the U.S. since 2012, plants with three or fewer gas turbines ("GT") per plant comprise nearly 60% of the total GTs installed:

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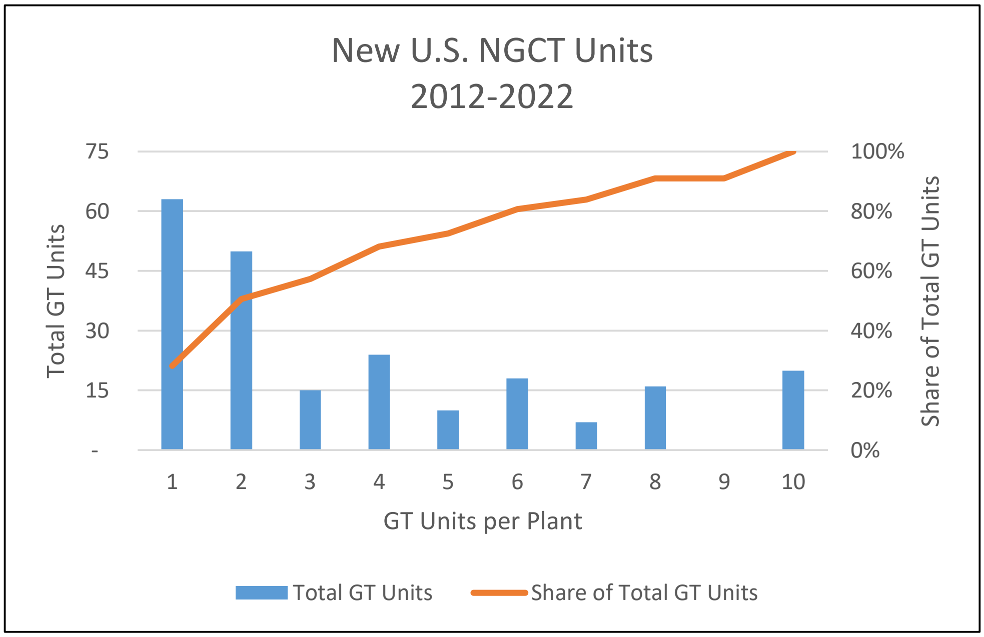
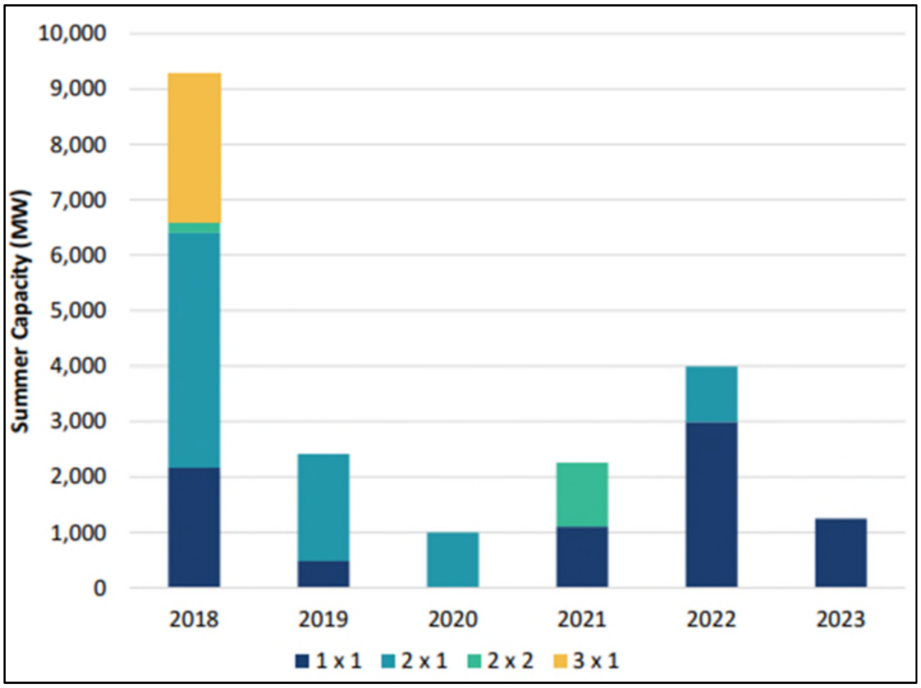
[11] *See* Direct Testimony of Snider et al., at 146.

[12] *See* U.S. Energy Information Administration, *Form EIA-860 detailed data with previous form data* (EIA-860A/860B), *accessed at* https://data.oecd.org/price/price-level-indices.htm.



The *atypical* nature of gas-fired plants with four or more units is even more apparent with combined cycles. As shown in the following tables from The Brattle Group's most recent report on gas plant costs in PJM, there are no combined cycle power plants operating in PJM with more than three units[13]:

[13] *See* The Brattle Group, *PJM CONE 2026/2027 Report* (Apr. 21, 2022), at 22, *accessed at* https://www.brattle.com/wp-content/uploads/2022/05/PJM-CONE-2026-27-Report.pdf.



Number of Trains	2018 (MW)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)	2023 (MW)	Total Capacity (MW)	Capacity Share (%)
1	1,184	485	0	1,104	0	0	2,774	35%
2	980	0	0	0	1,116	1,250	3,346	42%
3	0	0	0	0	1,875	0	1,875	23%
All CC Plants	**2,164**	**485**	**0**	**1,104**	**2,991**	**1,250**	**7,994**	**100%**

For the avoidance of doubt, I also compared the Duke cost estimates to the full range of market benchmarks for comparable resource types to determine if the Duke assumptions were more closely aligned with the minimum, average, or maximum benchmark cost totals. As shown in the tables above, the Duke estimates are out of line with market benchmarks for the same resource type from nearly every source and scenario reviewed. Duke's consistent overstatement of renewable build costs and understatement of gas build costs can clearly be seen from this data, which is fully supported through the publicly available source material cited above.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS ON THIS ISSUE.

A. In summary, Gabel's review of multiple publicly available cost benchmarks has been conducted in a fully transparent manner based on verifiable sources. This analysis unequivocally shows that Duke's resource capital cost assumptions used in its modelling are flawed, because they rely on unrepresentative cost assumptions that have the effect of inappropriately advantaging gas generators at the expense of renewable generators.

We recommend that the Commission accept the resource capital cost assumptions used by the Tech Customers in their Preferred Portfolio and require Duke to (1) update its resource build cost assumptions to align more closely with established market benchmarks showing higher gas generator costs and lower solar and battery storage costs; and (2) perform a revised EnCompass capacity expansion using these more representative assumptions.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

In the Matter of		
Duke Energy Progress, LLC, and	)	DIRECT TESTIMONY OF
Duke Energy Carolinas, LLC, 2022	)	MARIA ROUMPANI, Ph.D.
Biennial Integrated Resource Plans	)	ON BEHALF OF
and Carbon Plan	)	TECH CUSTOMERS

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 179

Direct Testimony of Maria Roumpani, Ph.D.

On Behalf of Tech Customers

September 2, 2022

Q. PLEASE STATE YOUR NAME, AND TITLE.

A. My name is Maria Roumpani and I am a Senior Manager at Strategen Consulting.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS DIRECT TESTIMONY?

A. I am submitting this Direct Testimony on behalf of the Tech Customers (Apple Inc., Google LLC, and Meta Platforms, Inc.).

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR DIRECT TESTIMONY?

A. No.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I am a Senior Manager at Strategen Consulting. The Strategen team is globally recognized for its expertise in the electric power sector on issues relating to resource planning with a focus on decarbonization, renewable energy, energy storage, utility rate design and program design, and market entry strategy. At Strategen, I lead economic and technical grid modeling engagements, including capacity expansion, production cost, and energy storage dispatch modeling for government clients, non-governmental organizations, and trade associations,

Before joining Strategen in 2018, I contributed to the development of analytical tools used in the European Union's energy impact assessment studies including the PRIMES Energy Model. I have a PhD from the Management Science and Engineering Department at Stanford University and a Master of Science in Electrical and Computer Engineering from the National Technical University of Athens, Greece.

Q. HAVE YOU PREVIOUSLY PROVIDED EXPERT TESTIMONY BEFORE REGULATORY COMMISSIONS?

A. Yes. I have testified before the Colorado Public Utilities Commission in Public Service Company of Colorado's application for approval of its 2021 Electric Resource Plan and Clean Energy Plan. Furthermore, I have supported numerous Strategen clients by drafting written testimony, drafting written comments, and participating in technical workshops on a range of proceedings in Arizona, California, Colorado, Kentucky, Nevada, North Carolina, Oregon, and South Carolina.

Q. CAN YOU DESCRIBE YOUR EXPERIENCE WITH AND EXPERTISE IN RESOURCE MODELING AND WITH THE ENCOMPASS MODEL USED BY DUKE IN THIS PROCEEDING SPECIFICALLY?

A. Yes. At Strategen, I specialize in mathematical model development and quantitative analysis for grid planning and operations issues, and in this role I have experience using different models, including EnCompass. I have reviewed and evaluated the Integrated Resource plans of utilities across the U.S., including in Arizona, Colorado, Minnesota, Michigan, Oregon, New Mexico, and Washington. I have provided technical support using EnCompass for comments filed in integrated resource proceedings in Arizona, and I have testified before the Colorado Public Utilities Commission presenting EnCompass modeling on the matter of the application of Public Cervice Company of Colorado for approval of its 2021 Electric Resource Plan and Clean Energy Plan,

Q. IS THE MODELING PRESENTED IN YOUR TESTIMONY CONDUCTED BASED ON THE COMPANY'S DATABASE?

A. Yes, my modeling was based on the database that the Companies used for their EnCompass modeling and produced in connection with their Carbon Plan filing. I adjusted a limited number of modeling inputs to better reflect the cost of new resource options, updated resource availability, as well as the gas price forecast based on information I received from Gabel Associates. For the capacity expansion step, I also edited certain model settings. The production cost modeling runs from which the emissions and final portfolios costs are derived were conducted using the same model settings as the Companies' modeling, including steps, time and commitment resolution. The runs presented were conducted using the same EnCompass version used by Duke. This ensures that the portfolio costs and emissions are compared on a consistent basis.

Q. PLEASE REMIND THE COMMISSION OF THE PROPOSED "PREFERRED PORTFOLIO" THAT RESULTED FROM THIS WORK.

A. As a result of our modeling efforts we were able to establish the viability of a "Preferred Portfolio" which yields a preferred outcome as compared to Duke's proposed portfolio. The Gabel/Strategen Report submitted on behalf of the Tech Customers on July 15, 2022 discusses our proposed portfolio in detail, but the chart below summarizes the resource additions selected by the Preferred Portfolio.

<u>Resource additions in the preferred portfolio (MW)</u>

Preferred	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036-2040	2041-2045	by 2050
CT J	-	-	-	376	-	-	-	-	-	-	-	-	-
CT J H2	-	-	-	-	-	-	-	-	-	-	-	1,503	7,516
2x1 CCJ	-	-	-	-	-	-	-	-	-	-	-	-	-
2x1 CCF	-	-	-	-	-	-	-	-	-	-	-	-	-
SMR	-	-	-	-	-	-	-	-	-	-	-	285	-
Adv. Reactor w/ Int. Storage	-	-	-	-	-	-	-	-	-	-	1,380	2,415	690
Onshore Wind	-	600	600	-	-	-	-	-	-	-	450	-	-
Offshore Wind (2029)	-	-	-	-	-	-	-	-	-	-	-	-	-
Standalone Solar	-	-	-	-	150	-	-	-	-	-	-	-	-
S+S 25% Battery Ratio, 4hrs	-	150	750	-	-	-	-	-	-	-	-	-	-
S+S 50% Battery Ratio, 2hrs	-	-	-	-	-	150	600	-	-	-	-	-	-
S+S 50% Battery Ratio, 4hrs	-	450	2,100	1,200	600	750	825	1,800	1,800	1,800	5,554	3,511	2,687
4-hr Battery	-	450	900	1,500	-	-	-	-	-	-	-	450	-
6-hr Battery	-	-	50	-	-	-	-	-	-	-	150	2,000	650
8-hr Battery	-	-	-	-	-	-	-	-	-	-	-	-	-
Bad Creek II	-	-	-	-	-	-	1,680	-	-	-	-	-	-

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. First, I address Duke's criticism that the Tech Customers' Preferred Portfolio is not reliable based on Duke's post-modeling SERVM analysis. Second, I discuss additional modeling sensitivities I conducted to address various concerns expressed by Duke's witness regarding the Tech Customers' resource cost assumptions, assumptions of Grid Edge demand reduction and availability of gas Power Purchase Agreements (PPAs)—all of which contradict Duke's criticisms and lend further support to the validity of the Preferred Portfolio. Finally, I address concerns I have with Duke's modeling methodology and its use of several out-of-model steps.

RELIABILITY: DUKE'S CRITICISM OF THE PREFERRED PORTFOLIO

Q. IN THEIR TESTIMONY, DUKE'S WITNESSES TAKE THE POSITION THAT THE TECH CUSTOMERS' PORTFOLIO IS UNRELIABLE. CAN YOU EXPLAIN THE RELIABILITY ASSESSMENTS PERFORMED IN CONNECTION WITH THE WORK SUPPORTING THE PREFERRED PORTFOLIO?

A. Duke's witnesses claim that the Tech Customers' Preferred Portfolio is unreliable based on an additional step that Duke performed outside of EnCompass, using a software model called "SERVM." Unfortunately, this step cannot be verified or even fully examined as intervenors did not have the option of running SERVM; Duke did not make that module available to intervenors nor is it a standard component of EnCompass. Furthermore, due to the short interval between Duke's testimony and intervenor testimony, we have not had the opportunity to fully evaluate the basis for Duke's analysis through discovery. Thus, in some respects, Duke's assertion is a bit of a "black box." Nonetheless, we have conducted further analysis in an effort to unpack Duke's claim. In his testimony, Mr. Borgatti discusses suspected analytical flaws that may be driving Duke's claims. Below, I describe additional modeling analysis I conducted that demonstrates that, even if one assumes the validity of Duke's assertions, the reliability issue is easily addressed without compromising the integrity of the Preferred Portfolio.

Q. DESPITE ANY CONCERNS WITH DUKE'S RELIABILITY ANALYSIS, DID YOU RUN AN ALTERNATIVE MODEL TO ADDRESS DUKE'S CLAIMS ABOUT RELIABILITY?

A. Yes. We appreciate that it is the Commission's role to ensure that any portfolio submitted to the Commission for consideration maintains system reliability. In an effort to eliminate any doubt as to the reliability of the proposed portfolio, we have conducted an additional run ("Adjusted Preferred Portfolio"). This portfolio includes the exact same resources as the Tech Customers' Preferred Portfolio but allows Belews Creek to retire later.

Q. ASSUMING DUKE'S RELIABILITY ANALYSIS WERE CORRECT, WOULD THIS ADJUSTMENT RESULT IN THE RESOLUTION OF THE RELIABILITY CONCERN?

A. Yes. According to Duke, the portfolio had a shortfall of 1,875 MW in 2030.[1] The Belews Creek units would provide 2,200 MW of firm capacity. It is important to

[1] Direct Testimony of Snider, et al., at 203.

note that this capacity is incremental to the Tech Customers' portfolio and would thus resolve any reliability concern raised by Duke in their testimony.

Q. HOW DOES THE COST OF THE ADJUSTED PREFERRED PORTFOLIO COMPARE TO THE PREFERRED PORTFOLIO?

A. In creating the Adjusted Preferred Portfolio, the Preferred Portfolio was not re-optimized, but only modified to include the Belews Creek units. By 2030, the Preferred Portfolio includes significant solar, storage, and grid edge resources, such that the Belews Creek units rarely operate and only address the alleged peak capacity need from Duke's reliability analysis. In fact, given that the Belews Creek units could also operate on natural gas, the Companies could continue exploring the option of reducing coal operations or even fully converting to gas.[2]

Maintaining Belews Creek only as a capacity resource would increase costs (NPV) by approximately $30 million for year 2030, and $180 million up to the end of 2035. If the units operate, they could provide energy value during a small number of hours and reduce the projected incremental costs. However, this would result in an increase in emissions. Specifically, if operating in 2030, the Belews Creek units would produce 0.7 million tons of CO2, which would still be lower than Duke's P1 by 0.6 million tons for the year.

To conclude, the Adjusted Preferred Portfolio addresses the Companies' reliability critique while maintaining lower NPVRR and emissions.

[2] Our analysis does not fully examine the gas conversion or coal operations options. We mention those as potential options for consideration.

ADDITIONAL SENSITIVITY ANALYSIS RESPONDING TO DUKE WITNESS CRITICISMS

Q. HAVE YOU CONDUCTED ANY ADDITIONAL MODEL RUNS SUBSEQUENT TO THE SUBMISSION OF THE GABEL REPORT TO FURTHER TEST THE PROPOSED PREFERRED PORTFOLIO?

A. Yes. To address various criticisms articulated by Duke's witnesses in their testimony, we prepared addition model runs to test various sensitivities that would allow us to better assess the validity of our initial conclusions and the main drivers of the model outputs.

Q. PLEASE SUMMARIZE THESE ADDITIONAL ANALYSES AND YOUR FINDINGS.

A. First, to assess the Companies' general critique of our resource cost assumptions as favoring renewable resources, we compared the cost of the Preferred Portfolio under Duke's original resource cost assumptions versus the costs using our proposed cost assumptions. This analysis showed that our Preferred Portfolio was less costly than Duke's regardless of which cost assumptions were utilized. Second, to analyze Duke's specific criticisms of Gabel's assumptions regarding Grid Edge (i.e., energy efficiency and net metering) and the availability of gas PPAs, we ran additional sensitivities (a "Grid Edge Forecast Sensitivity" and a "Limited Gas PPAs Sensitivity") to assess the significance of these inputs to our overall model conclusions. The sensitivities use the Preferred Portfolio's assumptions as their basis and then change one assumption at a time, to illustrate the impact it would have on the portfolio. Again, our findings showed that modifying these inputs did not materially impact our recommendations.

In sum, these additional analyses further support our conclusions that the Companies can leverage a number of different strategies and construct an alternative "no-regrets" path for the decarbonization of their system that is preferable to the path proposed by Duke.

Q. PLEASE ELABORATE ON YOUR SENSITIVITY ANALYSIS REGARDING RESOURCE COSTS.

A. Duke's witnesses make the allegation that intervenors proposing alternative models follow an outcome-oriented approach, claiming that intervenors inappropriately model lower costs for renewable and energy storage resources and higher costs for thermal resources. In his testimony, Mr. Kimbrough from Gabel Associates responds to the latter criticism and explains the basis for our assumptions for capital costs and why those assumptions are more reasonable than Duke's.

To test Duke's criticisms concerning resource cost assumptions, we compared the cost of the Preferred Portfolio using Duke's original cost assumptions,[3] with the cost of the Preferred Portfolio using the Gabel cost assumptions. I did not re-optimize or re-run the portfolio, but rather calculated its expected generation capital costs based on each party's assumptions. Interestingly, the overall net present value of revenue requirement (NPVRR) of the Preferred

[3] As specified in the EnCompass database and confidential workpapers (see Duke's Response to Public Staff DR 9-3).

Portfolio using Duke's resource cost assumptions is lower, which undermines Duke's contention that Gabel's resource costs, particularly for solar and storage, are underestimated.

Additionally, we compared the Preferred Portfolio using Duke's resource cost assumptions with Duke's proposed P1 with the same assumptions, and the results support the same conclusion. The Preferred Portfolio remains lower cost and lower emissions than Duke's proposed P1.

Table 1. Portfolio cost comparison (Net present value of revenue requirement) [4]

	P1 Repriced	Preferred
Duke Costs	$106,590	$104,383
Gabel Costs	$109,316	$105,403
2023-30 CO_2	299	290

**Million dollars and Million tons*

Q. DO YOU HAVE AN EXPLANATION FOR THIS RESULT?

A. First, these analyses help illustrate the reasonableness of our resource costs assumptions. More fundamentally, what I take from this analysis is that it is likely that the Preferred Portfolio remains less costly than Duke's proposed portfolio due to its selection of demand side resources and the avoidance of high operating costs of fossil fuel generation. The cost advantages associated with these resource selections likely drive the overall result, independently of which of the two sets of

[4] The reported NPVRR differs from the Gabel report, because a constant cost associated with planned resources in 2023-2025 inadvertently applied to all portfolios in the workpapers. It equally impacted all portfolios. The difference between the Preferred and P1 portfolios differs slightly due to the nuclear maintenance fix that Duke identified in their testimony.

resource cost assumptions is used. This analysis helps to tease out fundamental, meaningful differences in model approaches.

Q. PLEASE DESCRIBE THE ADDITIONAL "GRID EDGE SENSITIVITY ANALYSIS" THAT YOU CONDUCTED.

A. With this analysis, we sought to test Duke's criticisms of the Gabel Grid Edge assumptions, in particular the assumptions regarding the impact of the energy efficiency and BTM generation forecast on our conclusions. For purposes of our testing, we reverted back to the Duke assumed Energy Efficiency levels and significantly reduced the net metering forecast to represent approximately half of the originally assumed growth in the Preferred Portfolio. The resource additions resulting from this analysis are shown in Table 2:

Table 2. Resource additions in Grid Edge Sensitivity (MW)

Grid Edge Sensitivity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036-2040	2041-2045	by 2050
CT J	-	-	-	752	-	-	-	-	-	-	-	-	-
CT J H2	-	-	-	-	-	-	-	-	-	-	-	752	9,019
2x1 CCJ	-	-	-	-	-	-	-	-	-	-	-	-	-
2x1 CCF	-	-	-	-	-	-	-	-	-	-	-	-	-
SMR	-	-	-	-	-	-	-	-	-	-	-	285	285
Adv. Reactor w/ Int. Storage	-	-	-	-	-	-	-	-	-	-	1,380	2,415	690
Onshore Wind	-	600	600	600	-	-	-	300	-	-	450	-	-
Offshore Wind (2029)	-	-	-	-	-	-	-	-	-	-	-	-	-
Standalone Solar	-	-	-	-	75	-	-	-	-	-	-	-	-
S+S 25% Battery Ratio, 4hrs	300	600	1,050	-	-	675	-	-	-	-	-	-	-
S+S 50% Battery Ratio, 2hrs	-	-	-	-	375	375	-	-	-	-	-	-	-
S+S 50% Battery Ratio, 4hrs	75	750	1,950	1,200	675	750	1,725	1,800	1,800	1,800	5,480	3,620	1,921
4-hr Battery	-	400	900	1,500	-	-	-	-	-	-	-	450	-
6-hr Battery	-	-	-	-	-	-	-	-	-	-	-	1,700	500
8-hr Battery	-	-	-	-	-	-	-	-	-	-	-	-	-
Bad Creek II	-	-	-	-	-	-	1,680	-	-	-	-	-	-

Q. WHAT DID THIS ANALYSIS DEMONSTRATE?

A. The reduction of demand side resources leads to an increase in both energy and capacity needs. The optimal portfolio includes additional Carolinas (DEP and DEC) and imported onshore wind to address the energy needs and an additional combustion turbine in 2030 (December 2029), again after having exhausted the available energy storage additions. Both costs and emissions are higher than the Preferred Portfolio, an expected result as Energy Efficiency is one of the most economic resource options that the utility could pursue. However, the Preferred Portfolio still performs better than Duke's proposed P1 both in NPVRR and cost savings up to 2030.

Q. PLEASE DESCRIBE THE ADDITIONAL "LIMITED GAS PPAs SENSITIVITY ANALYSIS" THAT YOU CONDUCTED.

A. With this analysis, we sought to test Duke's criticisms of the Gabel assumptions regarding the available of gas PPAs in future resource selections. In our analysis, we assumed that out of the three PPA units that were originally included in the Preferred Portfolio, Duke would contract for additional capacity only with one. This represents a significant reduction in firm capacity that the gas PPAs were providing as originally modeled. For this reason, the model finds it optimal to add an additional combustion turbine in 2030 (end of 2029), as well as additional storage in 2032. However, the sensitivity portfolio still performs better than Duke's P1 both in NPVRR and cost savings up to 2030.

Table 3 below shows the resource additions resulting from this sensitivity analysis.

Table 3. Resource additions in Limited PPAs scenario (MW)

Limited PPAs	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036-2040	2041-2045	by 2050
CT J	-	-	-	752	-	-	-	-	-	-	-	-	-
CT J H2	-	-	-	-	-	-	-	-	-	-	-	-	6,764
2x1 CCJ	-	-	-	-	-	-	-	-	-	-	-	-	-
2x1 CCF	-	-	-	-	-	-	-	-	-	-	-	-	-
SMR	-	-	-	-	-	-	-	-	-	-	-	285	-
Adv. Reactor w/ Int. Storage	-	-	-	-	-	-	-	-	-	-	1,380	2,415	690
Onshore Wind	-	600	600	-	-	-	-	-	150	-	150	-	600
Offshore Wind (2029)	-	-	-	-	-	-	-	-	-	-	-	-	-
Standalone Solar	-	-	-	150	150	-	-	-	-	-	-	-	-
S+S 25% Battery Ratio, 4hrs	-	-	1,200	-	75	-	-	-	-	-	-	-	-
S+S 50% Battery Ratio, 2hrs	-	-	-	-	-	450	300	-	-	-	-	-	-
S+S 50% Battery Ratio, 4hrs	-	75	1,800	900	600	750	1,275	1,800	1,800	1,800	5,779	5,684	3,012
4-hr Battery	-	500	900	1,500	-	-	-	-	-	-	-	200	-
6-hr Battery	-	-	-	-	-	-	-	-	-	-	50	1,900	750
8-hr Battery	-	-	-	-	-	-	-	-	-	-	-	-	-
Bad Creek II	-	-	-	-	-	-	1,680	-	-	-	-	-	-

Q. PLEASE SUMMARIZE THE RESULTS OF THE SENSITIVITY ANALYSIS.

A. Table 4 below presents the results of the sensitivity analysis. It includes Duke's proposed P1, which is repriced to reflect same resource and commodity levels for a consistent comparison, the preferred and adjusted preferred portfolios, as well as the Grid Edge and the limited PPAs sensitivities. All portfolios outperform P1 in costs and emissions, showing that immediate new gas generation in the form of Combined Cycle generation is not required by the modeling.

Table 4. Summary results of sensitivity analysis[5]

	2050 NPVRR ($B)	*2023-30 CO_2*
P1 Repriced	$109.32	299
Preferred	$105.40	290
Adjusted Preferred	$105.20	291
Grid Edge	$109.16	296
Limited PPAs	$105.07	293

*million tons

MODELING: METHODOLOGY

Q. DO YOU HAVE ANY CONCERNS THAT DUKE'S MODEL CONSTRAINTS MIGHT BE OVERLY RESTRICTIVE?

A. Yes. I recognize that models are abstract representations of reality and as such are expected to have user-imposed constraints to capture some of the real-world limitations. However, in the case of Duke's Carbon Plan modeling, these constraints are so restrictive that they overly narrow the portfolio selection to a single choice: the addition of new gas resources. For example, in year 2028 the Roxboro Units 3 and 4 retire with a combined capacity of 1,409 MW. The same year, wind, either onshore or offshore, is not yet available, and solar is restricted to an annual limit of 1,050 MW. Imports are not included in the model.

No matter how advanced the model, the optimization follows the simplistic logic of meeting the energy and capacity need following those constraints without any flexibility. This results in the selection of new gas capacity even if a different

[5] The calculated NPVRR difference between the repriced Portfolio 1 and the Preferred Portfolio differs from the Gabel Report because of the fix on the maintenance rate of nuclear units that Duke discussed in their testimony, which reduces the need for additional resources in later years.

resource portfolio (absent annual resource limits) could be more economic. The value of using an advanced modeling tool and engaging in a complicated analysis is significantly diminished when the outcome is almost pre-determined. The table below shows the available maximum additions (cumulative MW) per year, indicating that the available solar resources would not be able to replace the retiring capacity. The Combined Cycle units are thus selected at the end of 2028 anticipating additional load growth and coal retirements in 2029.

<u>Table 5. Incremental resource limits and needs for years prior to 2030(MW)</u>

Year (BOY)	2025	2026	2027	2028	2029
Peak Load (Delta)	50	7	117	34	330
Coal Retirement		546		1,409	1,766
Solar			750	1,050	1,800
Onshore Wind					300
Offshore Wind					800
Standalone Storage	1,500	1,500	1,500	1,500	1,500

Q. HAVE YOU IDENTIFIED OTHER MODELING CHOICES THAT MIGHT RESTRICT THE SELECTION OF THE OPTIMAL PORTFOLIO?

A. Yes. I identify a number of modeling choices that restrict the selection of the optimal portfolio.

First, although I understand the computational difficulties of running such a large-scale model, we have concerns that the Companies' choice to segment the horizon to eight-year steps might bias the results, especially in the near term. Due to the Companies' modeling of capital expenses with declining annual values, certain resources including solar and batteries have higher costs in early years and lower later. When the model is optimizing based on a myopic horizon, this results in a suboptimal portfolio. The issue is exacerbated by the choice to set the first segment as 2022-2029, with significant energy and capacity needs in 2028 and 2029. It is worth noting that the first selection of any resource allowed in the model is in 2025 (Dec. 2024), which raises additional questions as to the segmentation of the planning horizon. The Companies are using an advanced optimization model and have developed detailed forecasts for technologies and prices up to 2050. But the most crucial decisions in the model, which will at a large extent define the Company's decarbonization path forward, are modeled within what essentially is a five year period - overly restricted by annual build limits. From my review and modeling attempts, I am concerned about this choice and the sensitivity of results on the model settings.

Second, the choice to model solar and storage resources with a fixed profile significantly undermined the value that the hybrid resources can deliver to the system. Similarly, the limited number of solar plus storage configurations was restrictive. This modeling issue, in addition to the need to model additional hybrid configurations, has been identified by several intervenors including Public Staff, the North Carolina Attorney General's Office, as well as the Tech Customers. In fact, the Tech Customers' Preferred Portfolio fixed this by allowing an additional solar plus storage resource to dispatch economically based on the system's simulated needs. This resulted in significant deployment of those resources in the Preferred Portfolio. In their supplemental portfolios, Duke fixed this by linking the solar and storage components of hybrid resources and allowing the latter to dispatch optimally. Duke recognizes that this is an improvement. I recommend that the Companies' modeling continues to reflect this functionality.

Third, the analysis includes several out-of-the model steps that introduce bias, errors, and make parts of the analysis a black box.

Q. PLEASE DESCRIBE YOUR CONCERN ABOUT THE "OUT-OF-MODEL" STEPS AND CALCULATIONS.

A. The Companies' methodology includes several steps that are conducted outside of the EnCompass model. Similarly, several calculations that could be performed by the model either in the pre-processing of inputs, or post-processing of results are performed outside of the model. These adjustments can bias the final portfolio selection, significantly reduce transparency, and increase the possibility of errors.

Q. PLEASE PROVIDE EXAMPLES OF THE "OUT-OF-MODEL" STEPS.

A. For example, the Companies' coal retirement analysis, despite the claims that it is model driven, is largely the product of manual adjustments that result in significant changes in the optimal retirement dates for coal units. Likewise, the transmission constraints that inform the manual adjustments have not been properly studied and seem to keep changing in different proceedings as outlined in Figure 16 of the Gabel Report. This reduces transparency and makes the review of the analysis and outcomes difficult for intervenors and the Commission. Our recommendations include a comprehensive transmission plan that would identify any potential needs driven by the coal retirements and provide more robust information for the coal retirement analysis.

Another concern is the replacement of batteries with Combustion Turbines, which is again done outside of the model. Because this step is done outside of the capacity expansion step in EnCompass, it essentially bypasses the selection of resources based on both their cost and their potential carbon footprint as weighted by the optimization under a carbon emissions reduction target. Furthermore, after forcing in a high number of thermal resources, the composition of the remaining portfolio is not again tested and might no longer be optimal. For example, after forcing in 1,127 MW of not economically selected combustion turbines at the end of 2027,[6] the Companies did not check whether investing in both combined cycle units remains economic. It could be possible that, by forcing in the additional thermal resources, the need for capacity is diminished at a level that does not justify the selection of additional gas combined cycle units.

An additional out-of-model step is the reliability adjustments that are addressing unserved energy in later years of the study. Those adjustments are significant and lead to the addition of three additional SMRs in portfolio P1. However, as recognized by the Companies in their testimony, those adjustments are largely the result of a modeling bug that forced all the nuclear units offline at predetermined dates, thereby creating a significant energy and capacity shortfall. Although the recognition that this step might no longer be needed improves the Companies' analysis, it undermines the trust in the methodology and all of the customized steps that are not part of the typical resource planning analysis.

[6] Duke's Response to Public Staff DR 9-10 (Portfolio 1 Project Summary).

Q. IN ADDITION TO THOSE STEPS, DID THE COMPANIES PERFORM OTHER CALCULATIONS OUTSIDE OF THE MODEL?

A. Yes, the Companies chose to perform many of the pre- and post-processing calculations outside of the model. For example, they perform the economic carrying charge calculation outside of the model. The economic carrying charge is meant to annualize the capital expenses associated with owning a resource and express them in terms of expected revenue requirement so that resources with different lifetimes are considered on a consistent basis during a finite horizon optimization. Duke performed this step outside of the model and included some of those capital expenses as fixed operations and maintenance expenses. This additional step (FOM adders), which I have not encountered in any other resource planning analysis, not only made the review more difficult for intervenors, but it might have had an impact on resource selection as outlined in Section 2.3 of the Gabel Report and was the cause of several issues around validation of model results. The effort, time, and multiple discovery requests could have been reduced had the Company utilized the EnCompass model functionality to perform the calculation.

In the same manner, the post-processing of results introduces errors. Instead of relying on EnCompass for the Revenue Requirement calculation, Duke removed certain costs from model and reconstructed them in workpapers. Several values in those workpapers were hardcoded and thus difficult to fully assess. One example is the calculation of the portion of the revenue requirement associated with the coal units. Duke calculated non-variable coal costs outside of the model prior to the coal retirement step. The model inputs included a single fixed cost value per coal resource per year that was meant to reflect the fixed operating and maintenance costs, the incremental capital expenses including environmental capital expenses, and finally the opportunity cost of delaying securitization. These costs were then again removed from the production cost simulation; then included back in revenue requirement workpapers. It is telling that the company had to provide several rounds of discovery to intervenors just to reconstruct these costs, which at a large extent remains a black box.[7]

Q. CAN YOU SPEAK TO SOME OF THE MODELING CHALLENGES YOU ENCOUNTERED IN YOUR WORK?

A. Yes. There was significant time and effort spent, particularly at the beginning of my work, in attempting to fix various problems with the model and inputs as provided to intervenors. This time and effort could have been dedicated towards additional analysis and reports that investigate additional pathways or sensitivities towards the state's energy transition. Some of the modeling issues encountered during the review of the Duke Carbon Plan included:

- Partial Units Export Error. One of the files provided to intervenors by Duke from the model user interface was not exported correctly. This error resulted in failed runs when attempting to use this file to replicate Duke's results. While we discovered this issue on or around June 1, it is our understanding that Anchor Power Solutions, the vendor of the EnCompass model, had already been notified of the problem and identified the root cause to the Companies on May 25. However, this was not communicated to stakeholders, and a correction was not provided until June 8, when the Companies posted a corrected data file on its Datasite.

[7] Duke's Responses to Public Staff DR 3-13, Public Staff DR 3-31, NCSEA DR 2-22, and NCSEA DR 4-24 provide portions of this analysis but included inconsistencies. The Companies ultimately corrected this with a supplemental response to NCSEA DR 4-24.

- Declining Cost Adder Issue. After resolving the partial units export error described above, the capacity expansion plan for investment in resources did not match the results provided by the Companies included in their portfolios. Anchor Power Solutions again supported the Companies in finding a solution and communicating it to parties via a posting to the Datasite on June 8, titled "EnCompass Input Data: Declining Cost Adder Issue and Resolution."

- Failure to Validate Results. Despite the fixes supported by Anchor Power Solutions described above, differences in the expansion plan, though smaller than before the correction to the Declining Cost Adder, are still present. Based upon communications with Anchor Power Solutions, we believe the output files posted by the Companies are inconsistent with the posted input files. This means that the input files published by the Companies do not produce the output files provided by the Companies. Therefore, the results of the Carbon Plan as filed by the Companies with the Commission cannot be completely replicated. Further, in Response to Public Staff Data Request 12-1, the Companies conceded that "due to time constraints, [it] did not make any test runs of scenarios on the development server before posting the input files on Datasite."

- Incomplete Documentation. As discussed, the Companies conducted several steps of the analysis outside of the EnCompass model. However, when the Carbon Plan was filed, only EnCompass files were provided. The pre- and post-processing steps that the Companies undertook were not documented through workpapers. This has resulted in intervenors spending significant time working on assembling and determining how the Companies chose the values stated in their Carbon Plan.

While I was eventually successful in overcoming these issues I would point out the significant efforts that were required to even begin substantive analysis.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

MR. SCHAUER: We do note that the testimony of Mr. Kimbrough has sections that are premarked as confidential and should be sealed as such.

Chair Mitchell, these witnesses also prepared witness summaries which are already filed in the record. We ask that the witness summaries be copied into the record as if given orally from the stand.

CHAIR MITCHELL: Motion is allowed.

(Whereupon, the prefiled summary testimony of Michael Borgatti, prefiled summary testimony of Adrian Kimbrough, and prefiled summary testimony of Maria Roumpani were copied into the record as if given orally from the stand.)

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**Summary of Testimony of Michael Borgatti
on behalf of the Tech Customers**

The purpose of my testimony is to support the recommendations of the Tech Customers offered in the Gabel/Strategen Report filed in this proceeding on July 15, 2022 ("Review of the Duke Carbon Plan Presentation of a Preferred Portfolio"). In support of the report, I respond to specific points raised in the direct testimony of Snider, et al., submitted on behalf of the Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (collectively, "Duke").

I briefly review the "Preferred Portfolio" presented in the Gabel/Strategen Report. This portfolio was prepared using the same EnCompass model utilized by Duke, starting from the inputs they provided. Using this model, we were able to establish the viability of an alternative portfolio that would achieve compliance with the 2030 carbon reduction goal, at less cost than Duke's P1, that is characterized by: (1) a significant expansion of solar and battery storage with recommendations to mitigate interconnection and transmission limitations; (2) enlarged investment in energy efficiency; (3) robust investment in behind-the-meter (BTM) distributed generation; (4) utilization of existing natural gas plants that can be contracted to avoid the construction of new units and the risk of stranded assets; and (5) following a no-regrets approach that preserves optionality.

My testimony also discusses the enactment of the Inflation Reduction Act, which further amplifies and supports several aspects of the Tech Customers' recommendations.

I discuss several challenges with Duke's proposed portfolios, including reliance on speculative technologies, reliance on significant new gas which may lead to stranded assets, and reliance on standard interconnection processes which historically have not realized the level of solar deployment that will be necessary to achieve the carbon reduction goal set by the legislature.

I further respond to several specific points asserted by Duke's witnesses. First, I show that Gabel reasonably projected the availability of gas PPA resources and that, in any event, additional sensitivity analysis showed that even with limited PPAs no new gas-fired generation was needed until December 2029. Second, I respond to the Duke's assertion that new gas is essential to maintain system reliability by pointing to NERC statements that caution against over reliance on gas and the various risks identified by numerous parties (including Duke) regarding gas availability. Third, I respond to Duke's assertion that the Preferred Portfolio did not pass Duke's out-of-model reliability screen by questioning the methodology utilized in performing this screen but noting that, even assuming the accuracy of Duke's finding and the appropriateness of its methodology, the issue raised by Duke can be addressed by extending the closing date for the Belews Creek facility. Finally, I respond to points made by Duke regarding the cost of renewable imports and transmission needs driven by coal retirements.

My testimony makes clear that the Tech Customers proposal is not intended as "the" only correct model, but rather it is intended to illustrate that an alternative approach – which diverges meaningfully from Duke's portfolios – is feasible. This approach leverages actions that are within the control of the utilities and the Commission, avoids short-term commitments concerning resources that either are not yet ready to be commercially deployed or may lead to stranded investment, and preserves full optionality over a diversity of resources to be considered in further iterations of the Carbon Plan.

Thank you for your time.

**Summary of Testimony of Adrian J. Kimbrough
on behalf of the Tech Customers**

My testimony primarily responds to the direct testimony of Snider, et al., submitted on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC ("Duke" or the "Companies") in support of their proposed Carbon Plan, specifically addressing the reasonableness of the resource capital cost assumptions underlying Duke's Carbon Plan. Based on my review of cost estimates from a number of reputable, publicly available sources, it is clear that Duke's cost assumptions for certain resources are out of line with market benchmarks—underestimating the cost of gas-fired generation resources and overestimating the cost of renewable generation—in a manner that biases Duke's modeling in favor of gas-fired generation and against renewable resources such as solar.

Thank you for your time.

Summary of Testimony of Maria Roumpani, Ph.D.
on behalf of the Tech Customers

The purpose of my testimony is to summarize the technical modeling support provided to Gabel Associates and the Tech Customers in the preparation of the Gabel/Strategen Report filed in this proceeding on July 15, 2022 ("Review of the Duke Carbon Plan Presentation of a Preferred Portfolio"), to address additional modeling that we have performed subsequent to the filing of the report, and to discuss various challenges we encountered in seeking to perform EnCompass modeling using the inputs and datasets provided by Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (collectively, "Duke" or the "Companies").

My testimony responds to the direct testimony of Duke's witnesses (Snider, et al.) asserting that the Preferred Portfolio faces reliability issues. In addition to the responses provided by Mr. Borgatti in his testimony, my testimony shows that any such issue could be resolved by a single change: allowing the Belews Creek plant to retire later than identified in the Preferred Portfolio, a change that cures the reliability issue while still resulting in lower cost, fewer emissions, and less execution risk than Duke's portfolios.

I also summarize additional sensitivity analyses we performed in response to Duke's criticisms. For instance, while Duke's witnesses criticize cost assumptions used in our modeling, even adopting Duke's cost assumptions, the Preferred Portfolio still outperforms Duke's portfolios from a cost perspective. In response to Duke's criticism about the availability of additional purchased power, our additional sensitivity analyses show that the recommendations that come out of the Preferred Portfolio are not materially changed by altering the assumptions regarding potential power purchases. In short, these additional analyses show that the Companies can leverage a number of different strategies to create an alternative “no-regrets” path to decarbonization of their system that is preferable to Duke’s proposed paths.

My testimony also identifies concerns with the modeling assumptions and methods employed by the Companies. These concerns include overly restrictive resource limitations that bias the modeling in favor of early construction of new gas generation; fixed profile modeling of solar and storage resources that led to underutilization of those resources in Duke’s portfolios P1-P4; and out-of-model steps undertaken by Duke, including adjustments to the retirement dates for coal plants, replacement of economically selected battery assets with Combustion Turbines, and performance of certain economic calculations outside of EnCompass, reducing transparency and undermining the role of the EnCompass modeling tool and the conclusions reached by the Companies.

Finally, I briefly address some particular issues encountered in working with the model as provided by Duke, and suggest improvements that may be made in future planning proceedings.

Thank you for your time.

MR. SCHAUER: Thank you. At this time, the panel is available for questions.

CHAIR MITCHELL: All right. CIGFUR, you are first.

MS. FORCE: Excuse me. Margaret Force with the Attorney General's Office. I have a couple of questions I'd like to ask. We didn't schedule time for it, but it will be brief.

CHAIR MITCHELL: All right. You may proceed.

MS. FORCE: Thank you.

CROSS EXAMINATION BY MS. FORCE:

Q. Margaret Force with the Attorney General's Office, and I have a question that follows up on some questions that were just asked in the earlier panel. I think you were all present at the time. We had questions from two Commissioners about difficulties running the model, and inferences that can be drawn from that.

And I had a question about one of the particular issues, whether you're familiar with it or not, having to do with nuclear units and the timing of outages of those units and how that appeared in the model. Is that a familiar issue to you?

A. (Maria Roumpani) Yes. Oh, sorry. Okay. I can take that one. So when we first ran the model, we went through the capacity expansion step, then in the production cost step, in later years we did see, observed a lot of unserved energy that would pop up in different places. And it wasn't intuitive as to why that was happening.

Our particular choice was to follow what the Companies did on that specific issue and add some units to address those. Although, in principle, like in research modeling, we have additional thoughts on this topic. For the purposes of the proceeding and because these appeared after post 2040, we chose to do that.

When the Companies filed rebuttal testimony, they identified a mistake or a modeling back, as they mention it, in the nuclear maintenance rate that made them probably, like, go into maintenance altogether, which caused this unserved energy here and there. So although it wasn't one of the first, you know, modeling difficulties that we had initially, I think, you know, what I'd like to say is that this particular issue of adding nuclear units to address unserved energy was one of the many steps that the Companies followed. I think it was, like, step seven or something. And that was particularly -- particularly important per the Companies for ensuring reliability. Well, it turned out it was a modeling bug. So, you know, it does raise some questions as to the necessity of all those steps.

Q. Thank you. And I just have one more question.

There were questions earlier about the experience of the teams who were preparing the prior panel's testimony, and I'm curious if you could relate the experience that you all have had with EnCompass, in particular, and how many years you've worked with it?

A. I was the one who conducted the EnCompass modeling. I generally have my background in economics and mathematic modeling. I have worked in developing such models, writing the equations behind them. EnCompass, in particular, I think I have experience since 2020. We've done several engagements with that. And I have provided testimony conducting EnCompass modeling before.

So that's for my experience, in general. For my experience now with the database and the issues that we experience in this case, as witness Fitch mentioned before, there were several issues that, you know, were partially resolved but resulted in, you know, cutting the time that we had to explore the model and understand the issues to maybe in half, and I'm being generous. Like, we had two to three weeks to actually work with the model -- with a working model that we could trust.

And they -- I can go, like, in detail into the issues. I think witness Fitch addressed many of those. My conclusion is they didn't allow -- the issues didn't allow for the time that we would have wished to have, and they raised questions around transparency. And I think the many steps that the Companies took out of modeling also introduced some errors.

A. (Adrian Kimbrough) So we also have some additional experience with respect to production cost modeling, energy markets, and the drivers that feed into production cost modeling. Myself, I have at least four years of experience with at direct production cost modeling at Gabel Associates, although not with EnCompass. We use a separate model.

But again, we have, you know, decades of experience, just between Mike and myself, understanding how the market drivers work, feed into production cost models, and how those can impact the results over long periods of time like we're observing here.

A. (Michael Borgatti) And I would agree with that entirely. And just add, you know, from where we sit in the universe for the clients that we represent, these types of models are determinative to the types of decisions they make, whether it's a utility like the Companies here that are talking about an IRP process, whether it's an institutional investor, private equity firm, a market buyer. So this is, sort of, our core competency for our firm. It's something that we do quite regularly.

Q. Thank you. I don't have other questions.

MS. CRESS: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MS. CRESS:

Q. Good afternoon. This is to anybody on the panel, so whoever is the most appropriate to answer, please do.

What is the range of net present value revenue requirements in Duke's primary portfolios presented in the Carbon Plan?

A. (Michael Borgatti) To be honest with you, for all of the different scenarios that have been presented, I'd honestly have to go back and refresh my recollection. I would say it's in the range of right around $110 billion or so, give or take. I'll also add that, over the course of discovery and in subsequent filings here, a number of the critical inputs have changed. So we've seen, for example, fuel costs that have changed, assumptions related to IRA, and things like that. And so if you were to ask me this question, you have to ask sort of which version of the Carbon Plan are we looking at. But I would say that 100-, $110 billion number is probably right around what we're -- what would be a reasonable approximation.

A. (Maria Roumpani) And if I may add, you can see, you know, I think in the filing, they started a little bit in the, you know, 90s to 110, but then in the intervenor modeling, you would see higher numbers because intervenors accounted for the increased gas prices and reviewed the cost of the natural gas units that was informing those revenue requirements. So even for the same portfolios, intervenors found them to be more expensive than the Companies found them to be.

Q. So is it fair to say that, in your opinion, the 100- to $110 billion range is likely to be an understatement or an underestimate?

A. (Michael Borgatti) So it certainty could be. And I think that's one of the primary considerations that we were looking to solve for in this report. And we've heard a lot of questions on, sort of, the caliber of the modeling, the ability or lack thereof to verify a number of the inputs here.

And when we start to look at, sort of, spend that is on that order of magnitude going out over a long period of time, we tend to look at what are the risks that are associated with those particular investments. And that, for us, was one of the material areas that we're looking at. And it's very difficult to capture in something like a production cost simulation.

So if you were to invest today in a combined cycle that you don't need 5 or 10 or 20 years from now because the portfolio changes, that shows up as what we would call a stranded cost or a stranded asset. Essentially, you've invested in something that isn't necessary for you from a reliability perspective or from a market-need perspective.

And so some of the areas that we have identified were those types of risks. We would see that SMR would fall into that too. It's certainly plausible that something like SMR could become a component of the Companies' overall long-term strategy for implementing this Carbon Plan, but that technology is nascent at this point. It is not market ready. And so certainly we could see a case where you could spend quite a bit of time and money hoping to develop resources that ultimately didn't end up coming to market. Again, that would be an incremental cost to ratepayers and something we were attempting to solve for in our analysis.

Q. Thank you for that. And how does the $100 billion to $110 billion range compare to Duke Energy's current market cap, if you know?

A. So the market cap, I want to say, is roughly $80 billion or so. So you're looking at 1.2-ish Duke's from a market cap perspective. It's a significant investment. It's very, very large. I think the total assets for the Company is about $120 billion if you want to get some sense on a total assets basis. So it's comparable to the size of the entire firm today.

Q. And I think this is my last question.

How many megawatts of new natural gas did the Tech Customers' portfolio select?

A. So I want to say it's roughly 350 megawatts of new natural gas-fired generation, and it appears far later in the term than it did in the initial scenarios and portfolios that the Company provided. I want to say it's 2029, if recollection serves me correct.

One of the other things to note there is that the way the Companies elected to perform their modeling, the year starts in December, right? So if I say a resource is needed in 2029, it's needed in December of 2029, so effectively you get 11 months of whatever year on top of, sort of, the round number that you would see in a chart that just showed you the years over time.

Q. Thank you. No further questions.

CROSS EXAMINATION BY MR. SNOWDEN:

Q. Good afternoon. I'm Ben Snowden here on behalf of the Clean Power Suppliers Association. Mr. Borgatti, I think this question is for you. And I'd like to start out by talking a little bit about solar interconnection.

A. (Michael Borgatti) Sure.

Q. So I take it from the Gabel report and your testimony that you do believe that Duke's ability to interconnect new generation under the current interconnection process is a source of execution risk for the Carbon Plan portfolios?

A. Yeah, very much so. And to be candid with you, I agree with the Companies on this. They've identified that as one of the major risks that they face here. For our analysis, we focus on an evaluation of Portfolio 1, because that's the only portfolio that achieves the carbon reduction goal by 2030. The rest of the portfolios were looking at 2032, 2034 as the period where they would achieve that objective.

And to be able to get to that goal, that would require the Companies, as I understand it, to interconnect roughly two-and-a-half times the amount of -- the highest amount of solar that they have ever interconnected in a single year, two-and-a-half times that number annually, right, from a point going forward.

And I'm gonna compliment the Companies on this. Their new cluster study process is a far better model than what they've done before. It is far more efficient. It is very consistent with what we see as a general trend in the right direction for how to administer these types of processes. But let's be clear, that is gonna be a tough putt. If anybody asks you to do two-and-a-half times better than the best that you've ever been able to do ever under the most efficient scenario that we're able to think of, you have to see that as an execution risk.

And so for us, we attempted to diversify pathways to markets for renewables expressly to try and address that risk in the portfolio. The objective here was to create a feasible pathway to that carbon reduction in 2030 and to set the state on that trajectory to achieve full decarbonization by 2050.

Q. Thank you. So, Mr. Borgatti, when you say two-and-a-half times what the Company's done before, that's 1,800 megawatts; is that --

A. Thereabouts, yeah, I think that's right.

Q. And to be clear, that -- that level of interconnection is not modeled in any of Duke's portfolios until a few years into the resource additions?

A. That's correct.

Q. Okay. And so you say you agree with the Company, and the basis for your agreement is just the Company's past rate of interconnection; is that right?

A. So that's part of it. And to be clear, like we're rooting for them. Like -- like we're hopeful that they're able to accelerate this type of interconnection. We just acknowledge that this is something that we see as a struggle nationally.

Like, for example, California ISO in April had to file a waiver with the Federal Energy Regulatory Commission to get a one-year extension for processing their cluster study model, which is similar in many respects to what the Companies do here, due to 141 percent increase in the number of projects that they had to process through that queue.

So these are difficult studies, they're really complicated, and when you exacerbate that by volume, you see problems. We've heard a lot about how the PJM interconnection process is a mess, it's going through a reform process in a way that candidly will look similar to what the Companies are doing here. One of the primary challenges that PJM has faced very, very large market, is volume.

So yes, I think the Companies', you know, concern is founded, but we've seen the same types of challenges in other jurisdictions.

Q. So just to clarify, the bases for your agreement with Duke are, one, the ratio of the projected interconnection to what Duke has done before; and two, what you have observed in other markets and jurisdictions; is that right?

A. Great summary. Yes.

Q. Okay. So in the report and in your testimony, you don't discuss any of the specific bases Duke articulates for the interconnection constraint in its MAL, right?

A. No, we do not.

Q. Okay. And you didn't conduct an independent analysis of the factors that Duke cites in favor of its interconnection limitation, did you?

A. No.

Q. Okay. And you mentioned this before, but you recommend in the report a couple of different strategies to mitigate the interconnection constraints; is that right?

A. That's correct.

Q. Okay. So that includes -- and I'm reading from the report, but that includes developing a holistic portfolio-based transmission expansion plan through the TPC, right?

A. Yes.

Q. Okay. Considering imports of carbon-free generation?

A. Yes.

Q. Generator replacement requests?

A. Yes.

Q. Okay. And then using surplus interconnection service from retiring coal facilities?

A. Absolutely.

Q. And those are your recommendations for dealing with the interconnection, right?

A. One quick just clarification on that last one, if I may. Surplus interconnection applies to operating units. So, like, let's say you have a combustion turbine that only operates 10 percent of the time, you could put a battery or a solar facility or something at the site, and it could use the other 90 percent of hours in the year to be able to put solar energy or to offer as a battery on the system. So I agree with you, just a clarification in how that pathway works.

Q. Thank you for that. So you'd agree, though, that if Duke were to, excuse me, begin using surplus interconnection service, it could facilitate more accelerated interconnections?

A. Oh, absolutely. So it's a process that -- there's a couple of advantages to this process. One, it exists, it exists today, it's FERC approved, and happens outside of the conventional, sort of, generator interconnection process that you would see here. And what it does is it allows you to effectively recycle the interconnection facilities for those existing CT resources.

So the time to market is shorter, the cost is cheaper, because you don't incur the transmission adder that we've discussed a lot here, and then you're just removing or alleviating the burden, sort of taking some of that volume out of the queue.

One other thing that, sort of, happened to be, I would say, a lucky coincidence for us, I should say, after we filed our report is the IRA, and we heard about some of the development value that may be available for replacement generation, taking coal plants and turning it into new resources, particularly renewables.

There's also money available for installing technologies that dramatically reduce the emissions profile for existing thermal generators. And we've seen in other jurisdictions cases where, in California for example, they've used energy storage resources in concert with existing gas plants to be able to reduce the emissions profiles for those assets by upwards of 60 percent.

And so you may actually be able to use

surplus interconnection not only to accelerate renewable and storage deployment, but also unlock some of that incremental value from the IRA.

Q. But Duke doesn't currently provide surplus interconnection service, right?

A. So it's available under their tariff. It's not included, to my knowledge, in any of the information about the Carbon Plan.

Q. Okay. Thank you. And I want to follow up on the generator replacement request procedure. And, Dr. Roumpani, this may be a question for you.

As I understand it, Gabel, or you-all, argued that by taking the interconnection service from retiring coal facilities, you could unlock a lot of interconnection, sort of, potential located at those facilities; is that about right?

A. Yeah, absolutely. I mean, the way to think about it is when the legacy coal plants -- and let's call it 9,000 megawatts for round numbers for purposes of our discussion here -- when those coal plants go away, that's 9,000 megawatts of space or headroom on the transmission system that something else like a solar facility or a hybrid or a battery resource could use. And so again, you end up with a faster process, or faster access to market.

You unlock the IRA value that the gentleman from RMI talked about before, but then you end up with lower cost, because you don't have to build new transmission facilities to interconnect those new resources.

Q. Thank you. So is the use of the generator replacement procedure reflected in Gabel's modeling?

A. Yes, it is. If I recall correctly, the retirement schedule -- and this is an important feature for why we elected to accelerate the coal retirements. I mean, obviously, there is a carbon reduction benefit from the most carbon-intense resources coming off the grid, but you want to make that space available as soon as you can in the model.

Like we talked about earlier, you have a lot of pressure on the interconnection queue. Freeing up that space sooner allows you to maximize the value of that and to incrementally increase the amount of renewables that you would put on the system.

Q. So you would agree that Gabel's reliance on that process for interconnection results in significant solar inter- -- significant solar additions being delayed until the time when that replacement interconnection capacity is available?

A. Sorry, could you repeat the question? I got lost in there. I apologize.

Q. Sure. Sure. Would you agree that reliance on that generator replacement process results in significant solar additions being delayed to 2028 or 2029?

A. Well, I don't know that I would say that they're delayed, right, because the other pathways to market would be available for those resources. But again, you're, sort of, looking at a ramp up in that time period to when, as we were saying earlier, that's when you really need to be putting this 1,800 megawatts on the system consistently.

And so at that area where you're gonna call, I'm gonna use the phrase peak demand for interconnection service, you're providing an additional available pathway.

And so I don't see that as precluding additional solar, I see that as, sort of, a pressure release valve on the interconnection process. We would say they should try to interconnect as much of this stuff annually as possible. Under all of the plans that are available out there today, solar is a huge component of the zero-carbon, low-carbon resource mix going forward.

I think we're just -- we were -- in the way we that approached this problem, tried to respect the reality that there are gonna be some challenges in accelerating that deployment to the extent that the Companies are gonna need to to hit that goal in 2030.

Q. Okay. Thank you. And I want to follow up on just one thing you said. You said the Companies should be trying to interconnect as much solar as possible?

A. Oh, yeah, absolutely.

Q. And so do you believe that the Company should be limiting their procurements targets to the amount of -- just the amount of solar that is added in their resource portfolio, or should they be trying to interconnect more than that?

A. I would think that they should be trying to interconnect more than that, right.

Q. Thank you.

A. Faster we can go, the better we will be.

Q. Thank you. To circle back on the generator replacement procedure, I'll try to ask it another way.

A. Sure.

Q. Is the fact that you-all rely on that in your model what explains the fact that have you very large additions of solar in 2020 -- in 2029, because that's when you've got retiring coal facilities?

A. (Maria Roumpani) Yes. So mathematically speaking, the way we translate it, what Mike just described to a model input, was that we allowed additional solar to be selected in the model in 2028, 2029. That reflects the capacity -- the coal capacity that was retiring.

Q. Thank you. So if I may try to sum up Gabel's approach to interconnection, as I hear your testimony, I'd say that you-all did not -- you-all generally accepted the Companies' proposed limitation on interconnection, but look for outside-the-box processes to alleviate stress on the interconnection process?

A. (Michael Borgatti) So I think that that's a fair characterization. Now, the total annual deployment limits, I believe we used the Companies' input in the first year, but after that, we did increase that to respect the idea that there would be these ultimate pathways available.

A. (Maria Roumpani) For the years that we had coal retirements not beyond 2030.

Q. Thank you. If you don't mind if I turn y'all's attention, do you have Duke -- Duke's rebuttal, the Modeling Panel rebuttal testimony?

A. (Michael Borgatti) I do not.

Q. It's Table 1. May I approach?

A. Sure.

CHAIR MITCHELL: Mr. Snowden, you need to slow down just for purposes of the court reporter, if you can, sir. And I'd ask the witnesses if you-all could make sure you're speaking into the mic so she can hear. You're kind of trailing off there at the end, and we need to hear every word.

THE WITNESS: Just shoot me, like, a head nod or a wink if I speed up too much for you and I'll do my best to slow down.

MR. SNOWDEN: You may just have to just wave at me. Sorry. I will try to slow down.

Q. So do you see that this is Duke Modeling Panel rebuttal testimony Table 1?

A. Yes.

Q. Okay. And this is -- for reference, I believe this is on page 96 of Duke's Modeling and Near-Term Actions Panel rebuttal testimony.

Do you see that this table purports to be a summary of the Company's proposed near-term actions with intervenors' suggested modifications?

A. Yes.

Q. Okay. And you all see where it says Tech Customers under alternative portfolios?

A. Yes.

Q. All right. And you see where it -- this table says that your near-term procurement recommendation is 3,450 megawatts; do you see that?

A. Yes.

Q. Okay. But that 3,450 megawatts, that is not a near-term procurement recommendation that is in your report or in your testimony, is it?

A. No, it's not.

Q. Okay. That's just what is added in your preferred portfolio through the 2028; is that right?

A. Yeah, that's exactly right.

Q. Okay. So -- and you testified a few minutes ago that you believe Duke should, for purposes of procurement, try to exceed the amount that is added in the portfolio; is that right?

A. Yes.

Q. Thank you. I'd like to move on -- well, let me ask a final question, then.

So would you agree that is it somewhat misleading in this table to suggest that the Tech Customers' recommended near-term procurement is 3,450 megawatts?

A. Yes.

Q. Thank you. I'd like to move on very briefly. And, Mr. Borgatti, I believe this is for you as well.

In the Gabel report -- I'm looking at page 15, but we don't have to get to the text -- you say that there are numerous examples of a coordinated portfolio-based transmission planning strategy; do you recall that?

A. Yes.

Q. And you say that it is a proven means of increasing renewable generation resources, facilitating decarbonization, and reducing customer cost; would you agree with that?

A. Yes.

Q. Could you just briefly cite some examples of jurisdictions or utilities that use a coordinated portfolio-based transmission planning strategy?

A. Yeah, absolutely. So two of the most recent examples would be the MISO and SBP, which are, sort of, the two ISOs and RTOs that span most of the center portion of the country. Kind of think about them as roughly the Rocky Mountain west, sort of, east to, kind of, the Mississippi River-ish in that area, just to give you a rough sense of where they are.

And both of those ISOs and RTOs have been engaged in this type of a proactive planning process for some time. For example, MISO just recently approved their LRTP, so their long-term transmission planning process, which is several billion dollars' worth of transmission facilities that they model to show a couple of features.

One would be the adjusted production cost by unlocking access to premium sites, better wind sheds, better areas for solar interconnection. They also alleviate interconnection constraints. These types of investments in transmission alleviate future reliability-based transmission needs, and so you're essentially spending today on transmission facilities that, sort of, tick all of those boxes, and then saving over the long run.

And you end up with literally billions of dollars -- I want to say it's between 70- and $150 billion, depending upon the scenario and where you look here as a result of that.

We're also seeing, in terms of generator interconnection, there is a joint interconnection transmission study process that's going on between MISO and SPP where they're looking at congested points of interconnection along their shared seams. And they're saying, okay, if we were to build these transmission lines, that would alleviate pressure on our queue.

There would also be benefits to network customers. Again, same kind of analysis, lower production costs, access to resources that meet state policy objectives. And they're saying let's allocate those costs between the generators that are in the queue and reflect some of the benefits on the grid.

And in both cases we see significant benefits from them. I will say SPP has shown the same results, in terms of a lower production cost, avoided upgrades, better reliable grid in their long-term transmission planning strategies as well.

Q. Thank you. I would like to move on, one last quick topic, and this is cost assumptions.

Do you happen to have the direct testimony of Duke's Modeling Panel?

A. No, I do not.

Q. Okay. I am looking at page 192. And I

apologize, I have to pull it out for you.
MR. SNOWDEN: Mind if I approach?
Q. Okay. We are on page 192 of Duke's Modeling Panel's direct testimony; do you see that?
A. Yes.
Q. And you see Figure 17 there?
A. Yes.
Q. All right. And you see that this shows a comparison of the assumed cost various modeling parties used in their respective models; do you see that?
A. Yes.
Q. And this chart appears to indicate that Gabel Associates used lower capital cost assumptions for CCs and CTs than did the Brattle Group; do you see that?
A. Yes.
Q. Okay. Would you agree that, all things being equal, if Gabel Associates had used lower capital expenditure assumptions for CCs and CTs than Brattle, then Gabel's model would be more likely to select those kinds of assets than Brattle's model?
A. (Adrian Kimbrough) Yes is the short answer.
Q. Okay. And by the same token, Gabel's modeling would be less likely to select solar storage or other resources?

A. If we're talking about the comparative cost of the two resources with gas being cheaper than solar, in that sense, yes. All else being equal, that's correct. If one resource is cheaper, it's gonna be selected faster than a resource that's more expensive, all else being equal.

Q. Thank you. And based on this chart, would you characterize the difference between the Gabel and Brattle costs for gas assets as significant?

A. (Witness peruses document.)

So just to confirm, the NC- -- or NCSEA costs are the Brattle costs; is that's what you're --

Q. Are the Brattle costs, yeah.

A. They don't appear significant but, I mean, it really depends on matter of perspective in terms of what you're looking at in this chart.

Q. Okay. Sorry.

A. Go ahead.

Q. Just to clarify, the CPSA versus Tech Customers. So CPSA is the -- I think I have that in color, that's the orange dot.

A. Yeah. Gotcha. Okay. So then the difference is it appears relatively significant between the two; that's correct.

Q. Okay. Thank you.

A. (Michael Borgatti) Maybe just to build on that, because I would agree with Adrian is that it looks significant. There are differences in some of the gas costs and some of the solar costs, but for the other resources, batteries offshore and onshore wind, they're comparable. The dots on the graph are kind of overlapping each other, so.

Q. Thank you. Now, are you aware that Mr. Hagerty, CPSA's witness with Brattle Group, said that, in formulating his CC and CT cost assumptions, he relied on cost assumptions from NREL figures, except that he used a 2026, 2727 PJM CONE study for the cost of CTs?

A. (Adrian Kimbrough) I'm not familiar with that testimony, but I am familiar with the 2026 Brattle CONE study.

Q. Okay. And, Mr. Kimbrough, you also rely on that CONE study in coming up with your CT cost; is that right?

A. That's correct that we did review it. We included it in our analysis.

Q. Okay. So would you agree that it would be reasonable for Mr. Hagerty to have relied on that same

PJM CONE study in formulating his CT costs?

A. In isolation, potentially, I think that the Brattle study provides a reasonable benchmark of CT and CC costs. From my experience and, you know, in that sense, if we're just talking about the comparative capital costs, I do think that that study provides a reasonable estimation of CC and CT capital costs.

Q. Thank you. And Mr. Hagerty and Brattle also rely on NREL sources, as do -- does Gabel and Associates, correct?

A. Correct.

Q. And you would agree that it would be reasonable for Mr. Hagerty to have relied on those NREL sources for purposes of coming up with CC and CT costs?

A. Again, not having any real detail about how he used those costs, in terms of coming up with a composite or average cost, I really can't speak to that. But just in terms of the benchmarks' reasonableness, themselves, I would say yes. Those benchmarks, meaning NREL and Brattle, are both reasonable for different reasons.

Q. But using those same benchmarks, you came up with a different set of costs?

A. We reviewed quite a few other benchmarks, and so that could be the basis for the difference between ours and the benchmarks that you're referencing. Again, we compared benchmarks -- cost benchmarks from a variety of sources. Some were higher, some were lower, but that was really -- that informed the basis of your analysis, right, to look at Duke's cost primarily to say, all right, are these reasonable. One of the benchmarks that we compared them against was Brattle.

Compared against Brattle, Duke's gas costs appeared to be unreasonable, because they were significantly lower than Brattle's estimates. Comparable findings were -- you know, we found for other resources as well, other benchmarks. And so it really depends upon which benchmarks you're considering, which ones they used in their analysis. We included quite a few, came up with an average estimate, a range of estimates to inform our analysis.

A. (Michael Borgatti) Yeah, and this is another area where maybe we just add some additional context on this. Directionally, we're moving in the same space as Brattle, right? I said earlier that, for the battery resources' onshore and offshore wind, a lot of parity in those costs.

In both cases we see the data sources that the folks over at Brattle looked at, that CONE study at NREL being two data points that were in our study. You see that the cost for the CCs and CTs directionally move into the same space that we see in the Gabel report based upon the proxies that we use.

You know, and another area that you got to appreciate here, one of the significant reasons that we've heard for the deviation in costs has been the unit selection that the Companies have picked. I know, in some of the earlier testimony, we heard a lot about the efficiencies that are intended to be gained from a four-unit CT configuration, as an example, where we would be essentially taking and saying we're gonna take four combustion turbines, four peakers, we're gonna put them all next to each other on the same site, and that's gonna create a much more efficient result using the same term and technology that, say, Sargent & Lundy, vis-à-vis Brattle, had used in that CONE study.

And what we end up seeing, though, in the analysis that the Companies have provided, they're specking out a J-class turbine and a GEHA combustion turbine. These are the two top-of-the-line technologies that are about 375 megawatts each. That's pretty consistent with the turbine ratings. If you go to the OEM's websites, you can look them up. You can see, sort of, where they are. That's right in the wheelhouse for those turbines.

You'll look, for example, at Portfolio 5 adjusted for the IRA inputs, which is the most recent analysis that the Companies put out, I'd like to say either late Thursday or very early Friday of last week. We see that, in their deployment, they show a single, right around 350-megawatt CT being deployed in DEC's territory, and then two CTs equaling 700 megawatts being deployed in DEP's territory.

And so while you could theoretically say maybe there would be cost advantages from having three turbines, they're in two different zones. So the advantages that you would have would go away because you would need to build those balance of plant features, that technology on two separate sites be able to get there.

I'd also add, and we talked about this a little as it pertains to the value or the benefit of siting resources on existing sites. And actually, this is something that we have a lot of experience with. I'm intimately familiar with the client that developed the one-by-one combined cycle unit on a brownfield site. And things like access to utilities, right? Recycling those interconnection facilities, cost advantage.

Combustion turbines, combined cycles, they need water. Typically coal plants also need water, right? These are big tea kettles. That's effectively how they're gonna generate electricity is by creating steam. Having access to water utilities can be helpful.

But brownfield sites also have significant risks associated with them. And in my experience, the environmental reliability for those sites is material, particularly for technologies like combined cycles and combustion turbines where you need to do things like pour footers, pole -- pipelines or laterals to be able to access that fuel. As soon as you start to disturb stuff that's under the earth on brownfield sites, you then incur liability and responsibility to remediate those facilities.

And that can be significant, particularly in the context of what we see here where, you know, ratepayers are ultimately going to be funding that investment. And if we find ourselves in a place where that remediation is necessary, that again would be an incremental cost that we would expect to see here.

And so those are two areas where, you know, when we look at the available proxies, we look at some of the bases as they've been described to us for the cost advantages, we trend in a direction where the data points that we see from Brattle, from NREL is consistent with what we see in our experience with practical projects that are out there, and less in line with the inputs that the Companies are providing and the justification for those inputs.

Q. Thank you, Mr. Borgatti. I just have one final question. And, Dr. Roumpani, this may be for you.

Notwithstanding the different CC and CT costs that were assumed in Gabel's and Brattle's model, would you agree that, in your modeling, that solar interconnection was a binding constraint that limited the amount of solar that could be selected economically in your model?

A. (Maria Roumpani) In certain years, definitely. It was a binding constraint in the Companies' modeling. It is a binding constraint in the Companies' IRA modeling where they have assumed the lower solar limits. And everything -- every other resource is binding, meaning that it's exhausted before, you know, the modeling selects a CC unit. Same in our modeling, I cannot say that in every single year it was binding, but for most years it was.

Q. Thank you very much. Those are all the questions I have. Thanks a lot.

CHAIR MITCHELL: All right. Public Staff?

MS. LUHR: I have no questions.

CHAIR MITCHELL: Okay. All right. Redirect?

MR. SCHAUER: No questions on redirect.

CHAIR MITCHELL: All right. Questions from Commissioners. Let's start with Commissioner Brown-Bland. Okay. Clodfelter?

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Mr. Borgatti, during a lengthy answer to one of Mr. Snowden's questions about the benefits of using the headroom created when you retire an asset and then you site the new asset at the same place, the benefits with respect to the cost of transmission upgrades avoided, you -- in the course of a long answer, you made some reference to a configuration -- technology configuration of gas paired with storage in California?

A. (Michael Borgatti) Oh, yeah, uh-huh.

Q. And you were claiming there were some benefits to that. I've been attuned to what parties are saying about the benefits of pairing solar plus storage, and I understand the benefits of pairing storage with nuclear facilities.

Talk to me about that resource configuration and how is it operated?

A. Yeah, absolutely. And, sort of, this is an emerging space. I think this is actually one, sort of, the coolest emerging technologies that is, sort of, out there. You know, when we heard from the operations panels here and the Companies, you know, concerns about what happens if all the batteries run out of energy for some reason as we start to model them. Legitimate, right? We are quite literally talking about transformational change in the way that the Companies are going to operate.

The grid here, reliability is an absolute paramount concern, we should be thinking very deeply about that. And we see gas represented in the Companies' modeling as a necessary bridge fuel for a period of time until, you know, we move and we're able to deploy a significant amount of renewables here.

What I was talking about was both, you know, potential for replacement generation. You could site a new resource here. But I was actually talking more about surplus interconnection, taking those existing facilities. And what the batteries do is, the most fuel-intensive emissions, intensive time for these peaking units, is when they start up, right? Because they crank really, really hard to start up very quickly and then begin putting a bunch of megawatts on the system as fast as possible. Makes sense, it's a peaking unit, right? You're using it in real time to adapt to whatever situation you need.

The battery sits there, and it's almost like a turbocharger for your car. There's no mechanical parts, there's no, sort of, fuel need or anything like that. And that resources is available to, sort of, instantaneously start to provide that need. It can provide reserves for you instantaneously and then defer the number of starts for those peaking units.

And so you can essentially have the battery be synced to the grid. That allows the CT to be synced to the grid, but you don't incur nearly as many starts. You also get the benefits of the additional ancillary service capabilities, which I think, in all jurisdictions that I'm aware of, ancillary services are a key component of maintaining reliability, particularly in a heavily intermittent type of system like the one that we're ultimately imagining here.

Q. So do I understand you, then, that what's being done there is you're simply deferring the number of times you cycle the CT unit?

A. Exactly.

Q. You're using the battery instead of a short cycle you might run on the CT, you're only ramping the CT when you want to run it for a longer peak?

A. Exactly. So if you need energy for six hours, you can use the battery for some period of time to begin with and the gas plant can take over. You're reusing the run hours. You also don't need to start that CT. And then that real-time condition that your managing to goes away, it has to run for a period of time and then turn off, right? Because, you know, these things can't just start and stop instantaneously.

Q. Who's doing that?

A. That would be operations.

Q. No, I mean which utility? You made a reference to a utility that may be doing that already. Who's doing it?

A. Yeah, there's actually -- there's two of these facilities that are out in California ISO. One is in Sacramento in a municipal electricity service territory. And if I recollect correctly, the other one is SMUD. So it's in SMUD, and then the other one is in San Francisco. I have a citation to it in our report, and I'd be happy to follow up with an exhibit.

Q. It's in the report?

A. Yes.

Q. If it's in the report, can you just give me the page reference and I'll follow it from there?

A. Absolutely. If you give me a moment, I can pull that up for you.

Q. Sure. Because I'm gonna ask you some other questions about the report here in just a minute, so you'll want to have it in front of you anyway.

A. (Witness peruses document.)

So it is footnote 48, and it is page 35 of the technical appendix that we filed with our report.

Q. Thank you. Let me ask you -- I want to ask you a question or two about your report, pages 42 through 45, Section 1.12, which addresses behind-the-meter generation. And I'm looking -- start out with page 44. Where I -- this really jumped out at me. I mean, your preferred portfolio differs from that of quite a number of other parties in this case, not just from Duke's, but from other parties in a very substantial behind-the-meter solar addition.

I think Duke is projecting less than 1 gigawatt by 2035, and you're saying we ought to go for 6 gigawatts. Six times the amount of behind-the-meter solar. And I've read this discussion on these three pages. I have not, I confess, yet followed any of the links that you give to some of the examples in New Jersey and Massachusetts and New York, so I haven't really had a chance to follow up on that and read it yet.

But I -- I really am curious. When I look at the examples you've given us here, from New York, from Massachusetts, from New Jersey, from California, one of the things that immediately jumps out at me when I think about those examples is rather significant rate differences that customers face in North Carolina as compared to those jurisdictions. And if I'm a customer trying to evaluate whether I want to install solar behind the meter, put it on my rooftop or on my factory top, I'm comparing that to my current cost of energy.

A. Sure, yeah.

Q. So in your modeling, did you take that into account? And if so, how did you take that into account?

A. (Maria Roumpani) So with respect to the EnCompass modeling, the net metering generation was an input that was developed by Gabel and Associates, so I don't know, Mike, whether you want to speak to how this was developed. But with respect to the EnCompass model, it was an input. Please join in, and I have one point.

Q. Is it, sort of, a generic kind of projection based upon experience across a number of different jurisdictions and you, sort of, apply some sort of averaging or something?

A. (Michael Borgatti) So in terms of the growth projections, yes. Now, another member of our team produced this analysis, so there may be areas where I would have to go back and would be subject to check here. But yes, if I recollect correctly, the BTMG cost estimates used the same inputs as the Companies. Again, subject to check here.

One other just area to add here, on the -- maybe two areas to add. IRA is another big factor here. And we saw the IRA analysis that the Companies performed, you might notice that any of the tax benefits associated with behind-the-meter generation was absent from that scenario. Under the right conditions, the IRA can provide a tax benefit equal to up to about 70 percent of the value of those BTMG technologies. Very significant in terms of a potential opportunity to incentivize, you know, significant deployment of those technologies.

Q. I appreciate that. I have looked at that late-filed exhibit that you're referring to.

A. (Maria Roumpani) Just if I may add that one is that in my testimony, I address this because we do recognize that it is a different assumption than other portfolios, so we included a sensitivity that speaks to that. So even absent these assumptions, our preferred portfolio still outperformed what the Companies presented.

Yes. And my second point would be on the IRA, which Mike already covered. And a third point is that from an execution standpoint, diversifying between the transmission and distribution side, in terms of solar, we are just -- again, as we've said many times, it was more of a diagnostic exercise. It was to provide alternatives to the execution issues that the

Companies are facing, and we thought that these could be an alternative.

Q. I will have a question for you in a moment about that Grid Edge sensitivity that you ran on your portfolio. I want to stay with the present line. And really, again, I'm just trying to get a handle onto when you develop the projections in the preferred case -- not in the sensitivity, I understand, but in the preferred case -- how you took into account current rate levels, rate differentials with other jurisdictions, and also income differentials between North Carolina and other jurisdictions. Massachusetts is general -- I suspect that their average family income is a little higher than North Carolina still.

A. (Michael Borgatti) I certainly can't speak --

Q. I mean, how are those things incorporated into your modeling?

A. So I would have --

Q. Just --

A. -- to go back again. Again, I apologize, another member of our team put that analysis together in his work papers. I could certainly follow up --

Q. All right. I'll stop, then. On page 44, there are some generic suggestions that are made about things the Commission ought to consider in order to achieve this level of penetration of behind-the-meter solar. One is revisions to net metering.

Do you have anything specific to suggest?

A. Yeah. So I think that there is a cap on the amount of net metered resources that are eligible for that program today, and certainly lifting the cap would increase the types of incentives that we would expect to see to stimulate investment in these types of resources.

You know, certainly we've talked a lot about, sort of, BTMG technologies, but if there are customers that want to site these for incremental reasons -- say you're a large industrial customer looking to achieve a corporate decarbonization objective -- facilitating or empowering those entities to use programs like these are really helpful.

And then what I like actually is the New York distributed energy resources, or their value of DER resources program. To me, it's a really interesting model because what we see here is that these programs help to offset the need for other expenditures on distribution infrastructure, transmission infrastructure, bigger power plants, and things like that. And inherently, those avoided costs have value. And the way that VDER program works is they quantify that value and then, essentially, credit back against that value the contract opportunity for folks that want to sign up with those resources.

That also allows you to enable things like community solar for folks that rent as opposed to own their own properties. Don't have the ability to, sort of, say I want to put a bunch of solar panels on my roof. It's not their roof. And I think that that program captures the exact type of calculus that you're saying. Like, what is the value to us of these resources, what is the value of those avoided costs, and also, again, another pathway to market that's not the interconnection queue that we've discussed already.

Q. Thank you.

Ms. Roumpani, I do have a couple of questions for you about your testimony. Do you have it there?

A. (Maria Roumpani) Yes.

Q. You ran the three sensitivities on the preferred portfolio and you've mentioned one of them.

A. Correct.

Q. I've read through this, and I have a fairly elementary kind of question, because something is missing -- I'm missing something when I read through it. So on page 11, you give me Table 1, which shows the net present value revenue requirement if you run the sensitivity on the resource cost issue.

A. Uh-huh.

Q. And then I go over to page 15, and I have Table 4 which does the net present revenue requirement comparison for the other two sensitivities, Grid Edge and limited third-party PPAs.

A. Uh-huh.

Q. And those are set out on a single table. And it's a really elementary question. I'm not sure why I had one table for the one sensitivity and then the other two are combined into a single table. What am I missing here?

Why aren't they shown in three tables or all shown as three different lines in a single table? I guess that's another way of asking my question, is something I'm missing with what you're trying to tell me here.

A. Okay. Yes. Absolutely. So I think the summary is provided in Table 4. That's one calculated revenue requirement per sensitivity. Now, if you go to

Table 1, that's not a different portfolio run. So we have two portfolios that I'm comparing. One is the preferred one and one is the Companies' P1. And I'm comparing those under different resource costs.

So the ones assumed by the Companies and the ones that we issue. So I'm -- you know, it is set out as to, like, understand and sensitize the results that we have based on the cost, but it is not only a single run. So what you're seeing here is, we're seeing P1 and we're seeing the preferred portfolio. I'm looking at Table 1. And how these would -- how the revenue requirement of those portfolios would be if we assumed the Companies' cost or the Gabel costs. And the outcome of that is that, in both cases, the preferred portfolio, even we assume the Companies' cost, is lower cost than P1.

Q. I understand. Thank you. It just -- as I say, such an elementary thing. I knew I was missing something.

The first sensitivity compares the same portfolios, just with different cost inputs, and the other two sensitivities compare different portfolios?

A. Exactly.

Q. Like I say, it was a pretty simple question, but it was escaping me. That's all I have. Thank you.

CHAIR MITCHELL: Commissioner McKissick, questions?

COMMISSIONER McKISSICK: I'll pass.

CHAIR MITCHELL: Okay.

COMMISSIONER McKISSICK: I think most of them have been answered.

CHAIR MITCHELL: Commissioner Kemerait, go ahead.

EXAMINATION BY COMMISSIONER KEMERAIT:

Q. Mr. Borgatti, I have, I think, just one question about execution risk related -- you talked about execution risk about standalone solar. And so I have a question about execution risk for solar plus storage and then standalone storage or batteries. In looking at your -- the table in your report on page 10, standalone storage has been significantly reduced, but solar plus storage is quite a bit higher than Duke's model, about 13,000 megawatts. And --

CHAIR MITCHELL: Is that confidential information? Can you --

THE WITNESS: (Michael Borgatti) It is -- yes, it is confidential.

CHAIR MITCHELL: Can you talk about it

relatively?

COMMISSIONER KEMERAIT: Yes. I'll speak in more general terms. I apologize.

Q. So for the execution risk -- and this is -- relates to Commissioner Clodfelter's question about batteries and placing batteries on existing sites. I think he was talking about peaker facilities?

A. Yup.

Q. Are you also contemplating potentially putting solar plus storage on those peaker facility sites or just the batteries?

A. I would say that we're open-minded. You know, this is -- the surplus interconnection pathway, as far as I'm aware, was not mentioned or considered at all in the Companies' proposal here. We should consider all avenues for the sites. You're essentially maximizing the value of that existing infrastructure. We should do it.

Q. And then for execution risk for solar plus storage, I think it's on page 28 of your testimony. You talk about the surplus interconnection service, and then you state that deploying solar plus storage of the Companies' existing thermal generator sites. And my assumption is that you view that as feasible because there would be no -- in your portfolio, little or no new natural gas that would be competing with the sites for solar plus storage.

Is that a correct assumption?

A. No, I don't think so. So I would say that the new natural gas would be competing in the replacement generation possess. So the Companies, as I understand it, are seeking to put the new CTs and CCs that they request permission to deploy in this proceeding on those replacement generation sites. It has a lot of the same advantages as surplus, but once you build that CC and you use up that headroom on the system and you use that land, that's gone, and that's gonna be a gas plant for 35 years, whatever the assumption is there.

So I would say that would be a case where you're essentially taking that high value, lower risk opportunity for renewables and you would, sort of, be locking that into those CCs and CTs. The surplus pathway -- you know, I'm kind of assuming that there's already a gas plant there, right? And you would maximize the efficiency of that gas plant -- that's another thing the Companies asked to do this in proceeding -- but you're then also taking the next step to say let's use that interconnection as efficiently as possible, and if we can do that while reducing emissions for that CT, all the better, in my view.

Q. I guess that was my next question, is that you're talking about existing sites that will continue to operate --

A. That's right.

Q. -- for the solar plus storage?

A. And that's right. So you can think about it when it's not sunny or the battery's depleted, the gas plant would be available to you. If the battery is fully charged and it was sunny, the solar could generate while the gas wasn't. They could sort of live in a symbiotic relationship like that and be available operationally to the Companies in that type of a fashion.

Q. And I guess my last question, then, is do you see any execution risk for solar plus storage under that scenario that you're mentioning like you talked about with standalone solar?

A. Yeah. So the -- you know, again, time allowed, we weren't able to go and look at all of the technical, sort of, nitty-gritty in-the-weeds detail of all 26, I think, peaking units that the Companies have in North Carolina. So some sites might be more suitable for others. For example, some of the properties might be too small for solar plus storage, would be an example of where it may not be feasible.

There may be the possibility that the battery could trigger upgrades as a load. You could then solve them through a public policy transmission planning process like we're doing in the red zone. So there are those risks. But again, there's lots of these different sites that are available. They're there, they're low-hanging fruit, they alleviate pressure on the interconnection queue, so, you know, a fulsome exploration of that possibility I think is warranted in this proceeding.

Q. Thank you.

A. Of course.

EXAMINATION BY CHAIR MITCHELL:

Q. Just a few questions for you all on -- I'm looking at Appendix A to the report, starting on page 15, and you discuss transmission planning, and you make some recommendations to the Commission of things that we can direct the Companies to do. And, you know, your recommendations occur on page 17 where you recommend that we direct the Companies to develop a coordinated portfolio-based transmission plan with the NCTPC.

Just backing up a little bit. You also state in the report that numerous examples show that a coordinated portfolio-based transmission planning strategy is a proven means of increasing renewable generation resources.

What example, specifically, are you talking about? Are they the SPP and MISO examples that you mentioned in the report?

A. (Michael Borgatti) Yeah, those are two of the more recent examples. Another example would be New Jersey and PJM have recently engaged in an RFP process to build strategic transmission infrastructure, kind of, throughout eastern PJM to facilitate their state public policy goals for offshore wind. That would be another good example of this. Public Staff also asked the NCT -- I also mess the acronym up. North Carolina Transmission Planning Collaborative to perform a public policy study with other configurations. For example, access to Midwestern wind and to see if that was an overall better outcome.

I would say all of those are examples of the types of processes that have been shown to deliver potential benefits to consumers here.

Q. Okay. The -- sort of the issues, though, of planning and cost allocation are separate, though they're very intertwined, obviously, when it comes to actually constructing transmission assets. And I think of the state agreement approach that New Jersey has entered into, I think it's the only state agreement approach that's been entered into at this time in PJ -- and PJM is addressing more of while there may be some studies that are undertaken pursuant to that state agreement approach, it largely addresses cost allocation.

So I'm curious here, how -- would the SPP example and the MISO example -- talk some more about what's going on in each of those RTOs that you think we can learn from that might be effective here in North Carolina.

A. Sure. And just a moment on cost allocation, because that's a legitimate concern, right, the --

Q. It is.

A. Absolutely -- I was involved -- I worked at the board of public utilities in New Jersey when Order 1000 came out, and I was directly responsible for leading that state's efforts to process how we were going to do public policy-based transmission planning.

And at the time, a number of entities were trying to propose a very large, very expensive offshore wind backbone and to get other states to sort of say yes to it and then have New Jersey pick up some of those costs.

And this tension between who pays for these public policy enabling upgrades is very real and is material. I will say that, under any scenario that you're looking at, that conversation is going to happen here in North Carolina, because all of the Carbon Plans in front of you are inter-regional Carbon Plans. The red zone transmission upgrades are split between North Carolina and South Carolina. That puts them in interstate commerce. That puts them in a federal jurisdictional pathway. They're using that public policy-based transmission avenue of Order 1000 to be able to sponsor those in the first run.

So this question about cost allocation, you're gonna face this. Does North Carolina have to site that infrastructure in their territories? If the utilities consolidate, do they have to have their ratepayers pay for lines that are ostensibly required for North Carolina's public policies? And I'll be honest with you, I'm very hopeful, I think there's a lot to learn from this proceeding. I hope that South Carolina follows you-all's good example here and embraces similar public policies. But that is a conversation that is inevitably gonna happen here in the future.

What we're saying here, and what SPP and MISO did and what PJM did was acknowledge that we are looking at solutions far off into the future, that we have these renewable goals, that we are going to have reliability issues that we see as potential concerns in the future; and to say, okay, what is the most optimal way to plan our transmission system to, say, alleviate interconnection backlogs, which is what the red zone upgrades try to do. To enable access to the cheapest, best renewables that are available. To integrate offshore wind in the most efficient way possible and say, hey, that's the future that we're aiming at. We're gonna spend a lot of money on transmission. Let's do it in the most efficient way possible, the most thoughtful way possible that maximizes and optimizes the value of that investment.

Why we think that's a good idea is, to a degree, it doesn't matter what resources you pick under any of these plans; all of them are gonna have to get plugged into this system. It, sort of, doesn't matter whether it's a solar facility or a wind farm or a battery, it's gonna need transmission --

Q. And I think we understand -- I understand your testimony now and I've read your report. I'm specifically interested in MISO and SPP. Walk me through what's happening in MISO right now.

A. Yeah. So the way that they're doing this is that they're looking at those drivers and they're saying there's value to it. So if I built this transmission line, there's a cost. And if I -- let's call it $1 billion, to pick a round number. And let's say that $1 billion in spend alleviates a $500 million reliability upgrade I would otherwise have to buy. Net net, I'm at $500,000, right? The cost is still greater than that.

But then if I say this unlocks access to better, higher value wind resource, and that drops my production cost by $1 billion, I saved $500 million in avoiding that upgrade; I saved another billion in putting the best highest value renewable resources on the system; I've got $1.5 billion in benefits in my example to $1 billion in cost. Let's pick that billion-dollar number off, because at the end of the day, that's the best most efficient solution for me.

And so that's the type of strategy that we would say here. We've heard a lot about imports and the value of imports are not -- whether or not the interconnection costs would be a factor here. We've only looked at one example, the Companies have only looked at one example, one of the interfaces with PJM, not the other interfaces with all of your other neighbors. It is absolutely fair to say that, while taking the facts as true as the Companies have stated them, I haven't looked at studies the way that they've had the ability to.

Those costs, in all likelihood, would be different across any of those other seams; there may be no costs across some of those other seams. And so to evaluate those types of scenarios and to make sure that you're making the best least-cost solutions through that transmission planning process is, I think, what MISO is doing, what SPP is doing, and it's a good rubric for the types of strategies you can adopt here.

Q. How is what MISO is doing different, just help me understand, than this approach that Duke has taken -- that the Dukes have taken in this proceeding, where they've identified -- they're pulling in these transmission projects associated with transmission constrained areas in their BAs? So how is that -- how is what MISO is doing, with the multidriver approach, different than what Duke is doing?

A. Yeah. So -- and I don't want to be overly critical of the Companies here, because I understand that they had a relatively short timeline to be able to put the plan together, too, right, and they were dealing with that constraint the same way that all of us were. But from what we understand, they looked at the transmission system in piecemeal. Okay, what's it gonna take to integrate offshore wind? We'll start with an 800-megawatt block then we'll add a 1,600-megawatt block and we'll think about that.

These red zone upgrades showed up in their interconnection studies, and we'll think about that separately. We know there's gonna be other reliability issues that have showed up, but they haven't considered whether, for example, changing the configuration of those red zone upgrades might offset a reliability project in some other part of their footprint.

And so when we think about what MISO is doing, MISO is saying, okay -- if we were to adopt the MISO model as an example, they would say our interconnection upgrades were the 500-and-change million dollars that we saw for those red zone upgrades. But let's see if for another $100 million, we could avoid $1 billion of transmission spend in another area of our footprint.

And that's the type of holistic analysis you would want to use to make sure that you're planning a grid in the most efficient, most effective way to achieve this public policy.

Q. Do you -- and I appreciate that explanation.

Do you -- are there any other -- are there any jurisdictions that you're aware of, outside of organized market structures, that are taking a more comprehensive or a holistic approach to transmission planning?

A. I would say Colorado would be another example of that. You know, out in the, sort of, Mountain West and Pacific Northwest we see some of those utilities making similar choices. BPA, kind of a unique animal in our space. Bonneville Power Authority has been engaged in in this type of planning processes too. So we do see it in other non-market areas as well.

Q. Okay. And just remind me, because I'm not clear on this, I don't remember.

Have any -- have there been any transmission projects actually developed coming out of the MVP process in MISO?

A. Yeah, there have.

Q. Okay.

A. There's a number of MVP projects. And honestly, those LRTP projects, very similar. MVP ended up being contentious, so I think they've kind of rebranded as long-term transmission planning. So very similar, but yes. That the short answer is yes.

Q. What was the contention?

A. So when MISO approved its public policy-based planning process, this idea as to whether or not some other state needed to pay for transmission that enabled one of their neighbor's public policies, that was essentially the issue. Because those MVPs were driving -- unlocking access to renewable resources. And one part of the footprint states that didn't have the same renewable energy objectives protested having to incur some of those costs. And that was the tension.

Q. Okay. So a minute ago you talked about interregional coordination. When you used interregional, I just want to make -- because we use

interregional in different contexts and different discussions related to transmission.
What did you mean, exactly?
A. You have to reflect my recollection of which example we were talking about.
Q. You were talking about what's going on in North Carolina as an example of interregional transmission. There's gonna be need for interregional transmission.
What do you -- did you -- how were you using the term "interregional"?
A. Sure. So if you look at the red zone upgrades as the simplest example of this, some of those upgrades are located in Eastern North Carolina, but others are located in the PD region of South Carolina. And so, you know, those are upgrades that are being proposed to the NCTPC as public policy-based upgrades. They facilitate this public policy.
It's a good idea, don't get me wrong, but at the end of the day, that is interregional. By definition, those upgrades span two states. South Carolina certainly has siting jurisdiction there. And so this is gonna be an interregional plan.
Also, if you think about it, the way we're

going to restructure these utilities is that they're gonna combine into one single Duke entity, right? DEC and DEP are gonna join together, and they're gonna be Duke North and South Carolina, right? And they're gonna then operate together in a way that is going to mean that resources in South Carolina are going to operate to support load reliability in North Carolina.

And so those assets are gonna function in a way that they are being directly used and operated in a way that's going to affect outcomes in South Carolina but facilitate your public policies.

And so those are examples of how we're gonna have to, sort of, deal with this. There's then the cost allocation problem. That MISO fight, we can certainly see cases where that could be a very real contention here between North Carolinians and South Carolinians. And then if they are one utility, not several utilities, how are we going to square that circle in a way that's efficient and effective here?

These are all really important considerations. They're the problems that you -- I don't want to call them problems. They're challenges, right, that we saw with the MVP projects. You're gonna see them now in this proceeding. And from my perspective, we haven't fully investigated the value or the benefits of saying, hey, if the risks that we're gonna get through this North Carolina/South Carolina collaboration are similar to what we would see in a MISO, an SPC, or a PJM, we haven't fully evaluated what the incremental benefits of that broader regional coordination would be.

Right off the bat, those transmission charges to point-to-point into your territory, those would go away. And so there are absolutely potential advantages there. But look, the challenges and the considerations here on, you know, ultimately that sort of interregional coordination aspect of this and planning, that's part of all these plans because they span two different states.

Q. Okay. Let me see.

(Pause.)

Q. Are you-all familiar with the provisions in 951 -- House Bill 951 that refer to customer generation or customer -- programs for certain types of customers? I'm paraphrasing because I don't have the statute at hand.

A. Are we talking about some of the CNI type of procurement programs and things like that? I am, yes.

Q. Okay. Let me grab my statute.

Are you-all aware of any discussions that have been ongoing about this type of program, the development of programs pursuant to that statutory provision in North Carolina?

A. Only to the extent that I understand that they are occurring. I don't have substantive knowledge about what's being discussed.

Q. They are occurring?

A. That's what I understand.

Q. Okay. I just wanted to make sure I heard you correctly. Okay. You-all make recommendations in the report about types of programs that the Commission could direct Duke to develop here. So I was just curious as to whether there were any types of programs under development. Okay. That's all have I.

CHAIR MITCHELL: Anybody else? Any other Commissioners have questions? Okay. Go ahead.

EXAMINATION BY COMMISSIONER McKISSICK:

Q. And really my questions go back to some of these, I guess, out-of-model steps that were discussed. And Chair Mitchell's -- some of her questions reminded me of some of these things that I had notated in going through some of the testimony here. I guess, Dr. Roumpani, when I go to page 18 of your testimony, I guess around line 21, you talk about adjustments that were made.

And one of your recommendations, beginning at line 21, deals with -- tangentially, but in a different way, says our recommendations include a comprehensive transportation plan that would identify any particular needs driven by the coal retirements and provide more robust information for the coal retirement analysis.

How do you see that all occurring and fitting together?

A. (Maria Roumpani) How do I see --

Q. Yeah.

A. -- the comprehensive transmission plan with the coal retirements?

Q. Yeah.

A. I think that's a question for you, Mike.

A. (Michael Borgatti) Sure. I can field that one. So the Companies have done some preliminary analysis on that, and for two of the units who -- forgive me, their names are escaping me. I want to say it's the Mitchell units, if I recollect correctly, and maybe Roxboro is the other one, if I recall. But there are transmission upgrades that are necessary to maintain reliability without those units.

Q. Yes.

A. However, those upgrades can be avoided by siting new generation on the sites, right? So you have a balance there. Do you want to build the wires or do you want to look at whatever type of generation technology could, say, accelerate you towards the -- kind of, clean energy objectives or, you know, meet reliability and provide other benefits? I would say that's the type of thinking that we were imagining in this section.

Q. In this particular context. Okay. And your second bullet here, it says another concern is replacement of batteries with combustion turbines which is done, again, outside the model, and you go into greater detail about that.

Could you elaborate further on your observations there? And that's gonna be top of page 19.

A. (Maria Roumpani) Yes. So the Companies, after conducting the capacity expansion step, which did not select in their original portfolios any combustion turbines, they did an additional step where they replaced up to, like, 35 percent of that -- of the storage capacity, that was a economically selected in the model with combustion turbines. Then they proceeded to do the production costs step.

My concern with that is that, you know, had it been economic, the model would have selected it. I understand there are trade-offs in the model in certain settings, but what they did, the Companies, is they overrode the modeling results and then didn't check whether those remained economic.

So, for example, you know, if we were to do, again, a capacity expansion model that forces in those, like, 1,300-megawatt of CTs, would the model still select two combined cycle units of that size, or would the model say, well, that's foreseen, there is already enough firm capacity, maybe one is needed? So that model was not done. It just increased unilaterally the firm capacity -- the natural gas capacity and proceeded to the production cost step without checking that these remains. At least cost portfolio under the Companies' assumptions.

Q. Okay. And, of course, there is no guarantee of firm capacity for gas anyway, is there?

A. Yes.

A. (Michael Borgatti) That's right. And that's true for the Companies' existing gas-fired resources as well as for the new ones. You know, if you look at the conclusion in Section N, I think the Companies state something like less than half of the combined cycles in their fleet have firm gas today, and they've got firm fuel for something on the order of 25 percent of their peak burn, you know, and that is a risk here.

It's a risk of adding new gas to a system that doesn't already have sufficient firm gas. You know, I understand that there are potential developments for pipelines and things like that that could improve that scenario here. I think whether or not you get the reliability benefits for those resources really does matter -- that firm fuel matters for the reliability benefit for those resources.

I think what our modeling shows, and certainly the other scenarios shows, that if gas is necessary, it's necessary later in the planning period, 2029, 2030, which would give you ample time to wait until a future proceeding to make a decision and to allow, sort of, the regulatory process on approving these pipelines to play out, have a better picture of what that firm fuel topology might look like for those assets.

Q. And as I recall in reviewing the testimony from this panel, at some point you made the observation that, in terms of the estimates and cost provided by Duke related to the CC and CT expansions, that they understated that cost, I think it was -- I remember something like 27 percent or something like that. Or -- and yet they -- yeah, they understated that, but then they overstated the battery cost and other related expenses.

Can you elaborate further on that? Kind of refresh my recollections.

A. (Adrian Kimbrough) You remember correctly. So that was going back to one of the discussions we were having earlier today where we were looking at the chart where we were comparing CC cost and CT costs, solar costs. And at a high level, the -- what happened with the Duke Carbon Plan was that it was -- it used cost assumptions that created an advantage for gas. Because it said, all right, gas, you are cheaper than every other benchmark and the market says you will be; and solar batteries, you guys are more expensive.

And so when you create these cost disparities, it means that gas is more competitive, solar and batteries are less competitive. So the model is gonna select gas faster than it will renewables. Solar and batteries most particularly.

Q. And as I recall, there was also a discussion about an out-of-model step relating to reliability adjustments that were addressing unserved energy in the later years and how it impacted the small modular reactors.

A. (Maria Roumpani) Yes. That relates to the AGO question we received at the very beginning as a panel. So the Companies had this, like, multistep approach where they did the capacity expansion, they added the batteries, they did the production cost, they checked for unserved energy. They found that there is some unserved energy, they felt -- they claimed it was necessary to add the small modular reactors post 2040. In the direct testimony, they acknowledge that this was due to a modeling bug, so that step was not needed. And there was no reliability in terms of unserved energy at all.

Q. Thank you. I think that clarifies things that were in the back of my mind in reviewing the testimony.

CHAIR MITCHELL: All right. Any

additional questions from Commissioners?

(No response.)

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

MS. CRESS: Thank you, Chair Mitchell.

EXAMINATION BY MS. CRESS:

Q. Mr. Borgatti, in response to a question by Commissioner Clodfelter regarding the panel's recommendation for increasing penetration of behind-the-meter resources, you testified that lifting the cap would stimulate investment by nonresidential customers; is that correct?

A. (Michael Borgatti) I believe so, yes.

Q. And by that, you're referring to the 1-megawatt cap on net energy metering?

A. Correct.

Q. Can you explain, in a little bit more detail, how that 1-megawatt cap prevents or restricts nonresidential investment in behind-the-meter resources?

A. Yeah. So, I mean, the way that we're thinking about that is that if you were to say that the BTMP limit would save the entirety of the customer facility load, then that would allow for incremental eligibility for that program, provide more of an opportunity for entities that were looking to take advantage of those programs to be able to deploy those types of resources.

Q. Thank you. Nothing further.

EXAMINATION BY MR. SNOWDEN:

Q. Mr. Borgatti, I have just a couple of questions to follow up on Chair Mitchell's questions about transmission planning. And the first -- there was some discussion of interregional coordination, regional planning, and cost allocation, and you referenced the possibility of a cost allocation, sort of, as between South Carolina and North Carolina. And this is just a -- I don't know the answer. But there has also been some concern raised about the allocation of costs for transmission and other things, but specifically for transmission upgrades as between DEP and DEC.

A. Yeah.

Q. Would it be possible, through either the local or the regional planning processes, to reallocate the cost of transmission upgrades as between the two utilities, assuming there was no merger?

A. (Michael Borgatti) Sure. I'm not sure necessarily about, sort of, reallocating. So once you build the transmission in one of the utility's territories, it sort of becomes dedicated to those utility customers. And I think that was the point that the Public Staff panel yesterday -- second Public Staff panel was getting at.

You know, I don't know that, after you spent the money, if you could, sort of, unwind that easily, right? But what you could do would be to say, okay, well, here's an upgrade that is entirely in DEP's territory. But here's an alternate scenario that, sort of, more equitably, fairly, however you want to characterize it, allocates those costs between the two utilities.

So when you're making a decision on which pathway forward, that would be a consideration that the Commission or anybody else could weigh and ultimately pick a different answer -- outcome.

Q. And that could be done in a proactive transmission planning process?

A. Absolutely, yeah. If we wanted to -- for example, we could say one of the things that we wanted to solve for was to make sure that there was a better balance in the costs between the utilities, and that could be one of the objectives of the study, if you wanted to go that route.

Q. Thank you. Are you familiar with the CAISO transmission planning process?

A. To a degree, yes.

Q. Okay. More than I am, I'm sure.

So -- and again, I understood, you know, that's an ISO, but it's a single-state ISO, right?

A. Yeah.

Q. So as I understand at least part of that process, the California Public Utilities Commission recommends portfolios to CAISO to be studied in that -- their transmission planning process.

A. Yes.

Q. Do I have that right?

A. You do.

Q. Okay. Is that -- do you think that would be a feasible way to approach, sort of, integrated transmission planning in North Carolina?

A. Yes, I would. You know, for example, here, as part of this proceeding, I know we're gonna focus on some near-term steps, but we're gonna have a bunch of portfolios that are available to us. As an initial step say let's pick one of those or some alternative scenario and say what would the transmission solution look like around there. So yeah, I would say that would be a very good example of how that could work.

Q. Okay. Thank you very much.

A. Of course.

CHAIR MITCHELL: Okay. We're gonna take our afternoon break. Let's go off the record, please. And we'll be back on at 3:35.

(At this time, a recess was taken from 3:21 p.m. to 3:36 p.m.)

CHAIR MITCHELL: All right. Let's go back on the record, please. Mr. Schauer?

MR. SCHAUER: Just a few questions, thank you, Chair Mitchell.

EXAMINATION BY MR. SCHAUER:

Q. Dr. Roumpani, if you could turn to page 15, Table 4, which you were discussing with Commissioner Clodfelter.

A. (Maria Roumpani) Yes.

Q. Could you just provide some -- an explanation of what this table is, in terms of preferred, adjusted preferred, Grid Edge, limited PPAs? What are those referring to, for the Commission's benefit?

A. Yes, of course. So the first one is P1.

This is exactly -- it's a portfolio that exactly imitates the resources that are included in the Companies' P1. We've just recalculated the costs associated with that portfolio, because we believe that the Companies have underestimated the gas costs, both capital expenses and the commodity prices.

And then -- so the preferred one is the one that is presented in the Gabel report. It includes several strategies that we think mitigate the cost associated with the construction of new natural gas resources. And then the three remaining ones, the adjusted preferred, Grid Edge and limited PPAs are sensitivities responding to criticisms that the Companies raised in their testimony.

So the first one, the adjusted preferred, responds to a criticism by the Companies that, in later years, the portfolio might have some reliability issues. So although I'm personally very skeptical of any reliability issues that the portfolio might have, I still acknowledge that, you know, it is good to provide the Commission with a portfolio that fully addresses that concern.

So what that portfolio does is, the Companies identify specifically what the capacity shortfall would be for the preferred portfolio in those years. So we added -- we allowed Belews Creek, the two units, to continue being on the system until the retirement date of, like, 2035, which the Companies have assumed. And that fully addresses the reliability issue. It adds 2,200-megawatt of firm capacity while the shortfall was maybe around 1,800, if I remember correctly.

So we've calculated, you know, the cost and emissions associated with that. It still outperforms the P1. So the Grid Edge sensitivity reduced significantly the Grid Edge forecast that we had included in the preferred portfolio, and we reoptimized everything. And again, we include the cost and the emissions associated with that.

And the third one, there was a criticism about the inclusion of existing gas PPAs in the preferred portfolio. So we significantly reduced those and again reran the portfolio. And came up with one that outperforms both in cost and emissions, P1.

Now, if I may add, when time allowed, I addressed all of those concerns in a single run together with some other concerns that the Companies have raised, which are the partial- or no-commitment issue. So I had a run that included partial commitment, full horizon, no PPAs, included the extended life for the Belews Creek -- again, it matches what the Companies have assumed -- and did not include a constraint on the selection of new combined cycle resources. And the result confirms what I have been sewing through the testimony, that no new gas is required up to 2030. Actually, that run, it didn't even include a combustion turbine.

Q. Thank you. Commissioner McKissick asked you about the out-of-model step regarding CT battery optimization.

Do you remember that exchange?

A. Yes.

Q. Have you reviewed Duke's IRA analysis that was submitted last week?

A. To the extent possible, yes.

Q. Right. Did they apply that out-of-model step to the IRA analysis?

A. Yes, they do. So the IRA analysis starts from SP5. So it has a compliance date of 2032, and it includes whatever was included in SP5. And then they do the run, the model selects one CC and one CT. The CT selected the end of 2030. And then they go through that CT battery replacement step again adding two CTs at the end of 2027, which were not economically selected initially.

Q. All right. So in other words, the IRA analysis forced in two CCs --

A. Yes.

Q. -- two CTs?

A. Uh-huh.

Q. Okay. Thank you. No further questions.

CHAIR MITCHELL: All right. At this time, I'll take motions related to these witnesses.

MR. SCHAUER: Thank you, Chair Mitchell. At this time, Tech Customers seek to move into evidence the Gabel report, both the public and confidential version, as well as exhibits MB-1 and MB-2, which were attachments to the testimony of Mike Borgatti.

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

(Tech Customers - Gabel Report and Exhibits MB-1 and MB-2 were admitted into evidence.)

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Ms. Roumpani, I want to be sure I understand something you just said in response to your counsel's questions on Commission's questions.

Were you telling us that you've run an additional sensitivity than the --

A. (Maria Roumpani) When time allowed, yes.

Q. And it's not one of the ones that's included in your prefiled testimony?

A. No.

Q. Has that been shown to Duke?

A. No.

MR. BREITSCHWERDT: Commission Clodfelter, we were just discussing the same issue, and we've not had a chance to see it. We also feel pretty strongly that was beyond the scope of any questions the Commission raised, it was beyond the scope of Ms. Roumpani's testimony, and so we don't think it's appropriate for the Commission to rely upon that analysis without affording us an opportunity to review it minimally, but I think my initial ask would be it be stricken from the record.

(Pause.)

MR. BREITSCHWERDT: So after discussing --

(Pause.)

CHAIR MITCHELL: All right. Here's what we're gonna do. We're gonna overrule the motion to strike. We're not gonna request a late-filed exhibit. Going forward, when we ask questions on Commissioners' questions, restate the Commissioner's questions and then ask your question. Restate the specific question and then ask your question, even if it's a long, rambling question that seems to make no sense, and be -- combination -- I'm not kidding. I'm not laughing. Restate the questions.

Any questions on that direction? Okay.

MS. THOMPSON: Chair Mitchell, just a clarifying question. Is it possible, in a situation like that, to ask the court reporter to read back the question, or is that not logistically possible?

CHAIR MITCHELL: You can -- you can -- that's gonna be logistically difficult if done in the middle of live testimony. But you can -- you have the advantage of YouTube. And, you know, if you've got a partner here with you, have them writing down questions so that you can be ready to restate that question for us.

MS. THOMPSON: Thank you for that clarification.

CHAIR MITCHELL: With that, you-all are excused, you may step down.

CUCA, call your witness.

MR. SCHAUER: Thank you, Chair Mitchell. At this time, CUCA calls Kevin O'Donnell to the stand.

CHAIR MITCHELL: All right. Mr. O'Donnell, raise your right hand, please.

Whereupon,

KEVIN O'DONNELL,

having first been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION BY MR. SCHAUER:

Q. Mr. O'Donnell, can you please state your full name and business address for the record?

A. Kevin O'Donnell. Business address, 1350, Suite 101, Southeast Maynard Road, Cary.

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

A. I'm the president of Nova Energy Consultants.

Q. Have you testified before this Commission previously?

A. Yes.
Q. Did you cause to be filed in this proceeding on September 2, 2022, direct testimony consisting of 17 pages and an appendix of four pages?
A. Yes.
Q. Do you have any corrections to your testimony?
A. No, I do not.
Q. If you asked you the questions in your prefiled testimony today, would your answers be the same?
A. Yes.
Q. Did you also have prepared a testimony summary that was filed in the docket?
A. Yes.
Q. All right.

MR. SCHAUER: Chair Mitchell, at this time, we move that the direct testimony of Kevin O'Donnell and the testimony summary be copied into the record as if given orally from the stand.

CHAIR MITCHELL: Motion is allowed.

(Whereupon, the prefiled direct testimony and Appendix A of Kevin O'Donnell and the prefiled summary testimony of Kevin O'Donnell was copied into the record as if given orally from the stand.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

In the Matter of		
Duke Energy Progress, LLC, and	)	DIRECT TESTIMONY OF
Duke Energy Carolinas, LLC, 2022	)	KEVIN O'DONNELL
Biennial Integrated Resource Plans	)	ON BEHALF OF
and Carbon Plan	)	CAROLINA UTILITY CUSTOMERS
	)	ASSOCIATION, INC.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 179

Direct Testimony of Kevin W. O'Donnell, CFA

On Behalf of Carolina Utility Customers Association, Inc.

September 2, 2022

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Kevin W. O'Donnell. I am President of Nova Energy Consultants, Inc. My business address is 1350 Maynard Rd., Suite 101, Cary, North Carolina 27511.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am testifying on behalf of the Carolina Utility Customers Association (CUCA). A number of CUCA members take electric service from Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC) and the outcome of this proceeding will have a direct bearing on these CUCA members.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND RELEVANT EMPLOYMENT EXPERIENCE.

A. I have a Bachelor of Science in Civil Engineering from North Carolina State University and a Master of Business Administration from the Florida State University. I earned the designation of Chartered Financial Analyst (CFA) in 1988. I have worked in utility regulation since September 1984, when I joined the Public Staff of the North Carolina Utilities Commission (NCUC). I left the NCUC Public Staff in 1991 and have worked continuously in utility consulting since that time, first with Booth & Associates, Inc. (until 1994), then as Director of Retail Rates for the North Carolina Electric Membership Corporation (1994-1995), and since then in my own consulting firm. I have been accepted as an expert witness on rate of return, cost of capital, capital structure, cost of service, rate design, and other regulatory issues in general rate cases, fuel cost proceedings, and other proceedings before the North Carolina Utilities Commission, the South Carolina Public Service Commission, the Wisconsin Public Service Commission, the Virginia State Commerce Commission, the Minnesota Public Service Commission, the New Jersey Board of Public Utilities, the Colorado Public Utilities Commission, the Oklahoma Public Utilities Commission, the District of Columbia Public Service Commission, and the Florida Public Service Commission. In 1996, I testified before the U.S. House of Representatives' Committee on Commerce and Subcommittee on Energy and Power, concerning competition within the electric utility industry. Additional details regarding my education and work experience are set forth in Appendix A attached to this testimony.

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

A. The purpose of my testimony in this proceeding is to review the application of DEP and DEC to implement its Carbon Plan that will reduce the carbon output from electric generating units throughout North Carolina.

II. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS IN THE APPLICATION OF DEC AND DEP AS TO ITS PROPOSED CARBON PLAN.

A. I am offering testimony on the following issues identified in the Commission's July 29, 2022 *Order Scheduling Expert Witness Hearing, Requiring Filing of Testimony, and Establishing Discovery Deadlines*:

- **Modeling**: While Duke presented reasonable natural gas and coal cost projections in its initial filing based on forecasts that existed at that time, those cost forecasts are now woefully inadequate and the entire analysis should be adjusted accordingly and re-filed. Duke does mention the lack of interstate natural gas capacity in North Carolina, but it fails to adequately discuss possible options to address the interstate natural gas inadequacies.
- **Transmission Planning**: DEC and DEP did not address potential problems from the siting of new transmission lines and how those lines may affect the implementation of the Carbon Plan and its associated costs.

- **Cost**: The cost impacts noted by Duke in the Carbon Plan are inadequate in that the plan does not include grid modernization costs, some of which are currently in DEC and DEP deferred accounts awaiting a ruling in the next rate cases for the utilities. DEC and DEP should present a holistic approach to the actual costs each customer class in North Carolina can reasonably expect in the next 10-year and 20-year period when the Carbon Plan costs are combined with the grid modernization costs.
- **Cost**: Duke should be required to meet cost goals and carbon reduction goals as outlined in its Carbon Plan with adjustments for inflation taken into account.

III. MODELING: OUTDATED NATURAL GAS FORECASTS

Q. DID DUKE USE THE MOST RECENT NATURAL GAS AND COAL FORECASTS AVAILABLE TO IT WHEN THE CARBON PLAN WAS FILED IN APRIL OF 2022?

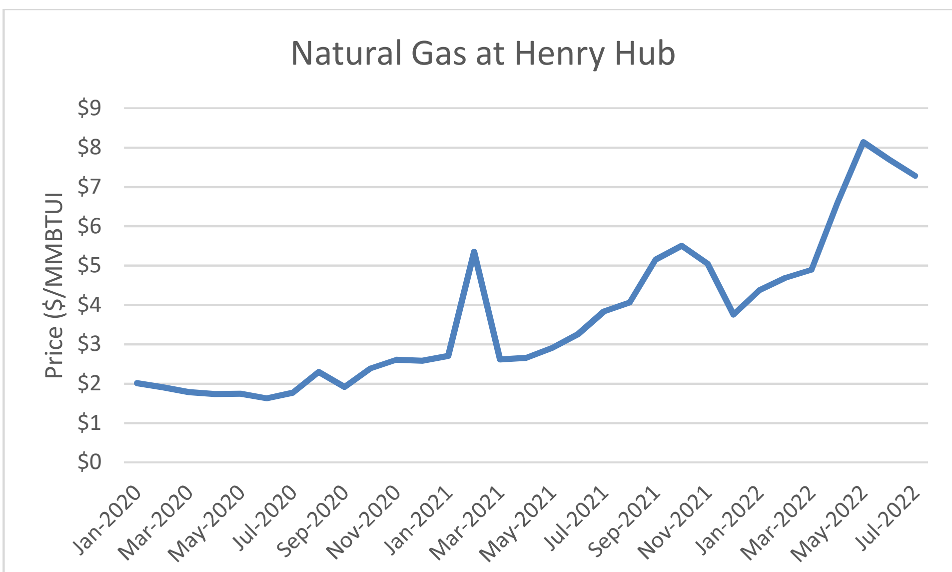
A. I assume Duke would have used the most recent forecasts available to it at the time the plan was filed, but much has changed in the energy commodity markets since the Carbon Plan was filed.

Q. WHAT HAS CHANGED IN THE PAST 6 MONTHS THAT NECESSITATES AN UPDATE IN THE DUKE CARBON PLAN?

A. In the past 8 months, natural gas and coal costs have shot upwards causing financial hardship for millions throughout the world. The most obvious drive of the cost increase has been the Russian invasion of Ukraine and the subsequent slow down of natural gas deliveries from Russia to its European customers that have been supporting Ukraine in the war. The United States has stepped into the breach from the loss of Russian natural gas by sending liquefied natural gas (LNG) to our European allies.

Secondly, the United States economy was hot in late 2021 and early 2022 due to pent up demand coming out of COVID. This demand for natural gas also led to the run up in prices. Chart 1 below shows the tremendous price increase of natural gas at Henry Hub.

<u>Chart 1: Natural Gas Prices from 2020 to Present[1]</u>



[1] Source for raw data: https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm

The above-stated costs are actually low for delivery into North Carolina. As the Commission is well aware, North Carolina is served by only one interstate natural gas pipeline, Transco. Unfortunately, demand has been quite high on Transco this summer as coal shipments have been somewhat spotty. In DEC's South Carolina fuel case, Company Witness Verderame explained the situation in the coal markets as follows:

> In addition, the coal supply chain experienced increasing challenges throughout 2021 and the first half of 2022 as historically low utility stockpiles—combined with rapidly increasing demand for coal, both domestically and internationally—made procuring additional coal supply increasingly challenging. Producers were unable to respond to this rapid rise in demand due to capacity constraints resulting from labor and resource shortages. These factors combined to drive both domestic and export coal prices in 2021 and the first half of 2022 to record levels. Going into summer 2022, coal commodity costs remain at historically high levels as higher natural gas prices and strong domestic and foreign demand continue to put pressure on coal supplies.[2]

To make up for the energy not generated from coal, DEC's natural gas burn increased from 133.1 million MBTU to 217.2 million MBTU, representing an even more dramatic increase of 63%. The cost for natural gas increased from $3.16 per MMBTU in the prior test period to $4.96 per MMBTU in the current review period.

Simply put, coal was not available in quantities expected by DEC in the current test period and, as a result, it had to buy an extensive amount of natural gas in the marketplace to fill the hole left by coal. The marketplace reacted to the huge demand for natural gas by driving up the price.

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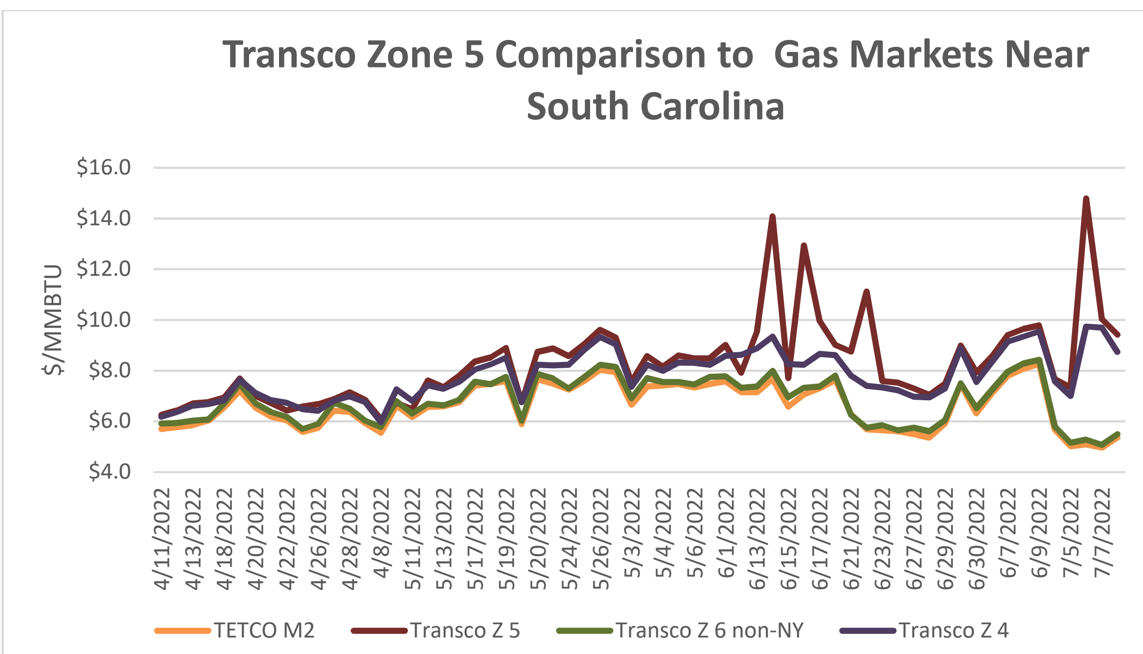
[2] *Annual Review of Base Rates for Fuel Costs for Duke Energy Carolinas, LLC, Increasing Residential and Non-Residential Rates*, Prefiled Direct Testimony of Verderame, P.S.C.S.C. Docket No. 2022-3-E (July 29, 2022), at 7.

In addition to the above-stated increase in the cost of the commodity, natural gas, the cost of delivering the gas to North Carolina also increased dramatically.

Q. PLEASE EXPLAIN THE INCREASE IN THE COST OF DELIVERING NATURAL GAS TO NORTH CAROLINA

A. DEC takes its natural gas supplies from the Transco Interstate Natural Gas Pipeline at Transco Zone 5. Unfortunately, Transco Zone 5 is highly constrained. Chart 1 below provides the price delivered at the following zones: Transco Zone 4 (Georgia), Transco Zone 5 (North Carolina, South Carolina, Virginia), Transco Zone 6 non-NY, and Texas Eastern Transmission Company (TETCO) M3 (Kentucky, Ohio, and West Virginia) from early April 2022 through early July 2022.

<u>Chart 2: Zone 5 Price Comparison</u>



From April 11, 2022, through July 7, 2022, the market prices at Zone 5 have averaged $1.21/MMBTU MORE than the average of TETCO M2, Transco Zone 4, and Transco Zone 6 non-NY. There have been days this year when the cost of delivering natural gas into Zone 5 Transco was over $14 per MMBTU.

Q. WHAT IS DRIVING THE INADEQUATE SUPPLY OF CAPACITY ON THE TRANSCO SYSTEM?

A. Over the past 14 years, the commodity cost of natural gas has decreased to a point where natural gas has become the fuel of choice for electricity providers. Not only has natural gas been cheaper than coal, but natural gas also produces less carbon than burning coal. Much of the available natural gas capacity on Transco at Zone 5 has been taken by electric generators, both investor-owned utilities and merchant generators. The end result is that North Carolina is facing a severe challenge that will impact our ability to grow. Simply put, we need much more interstate natural gas capacity.

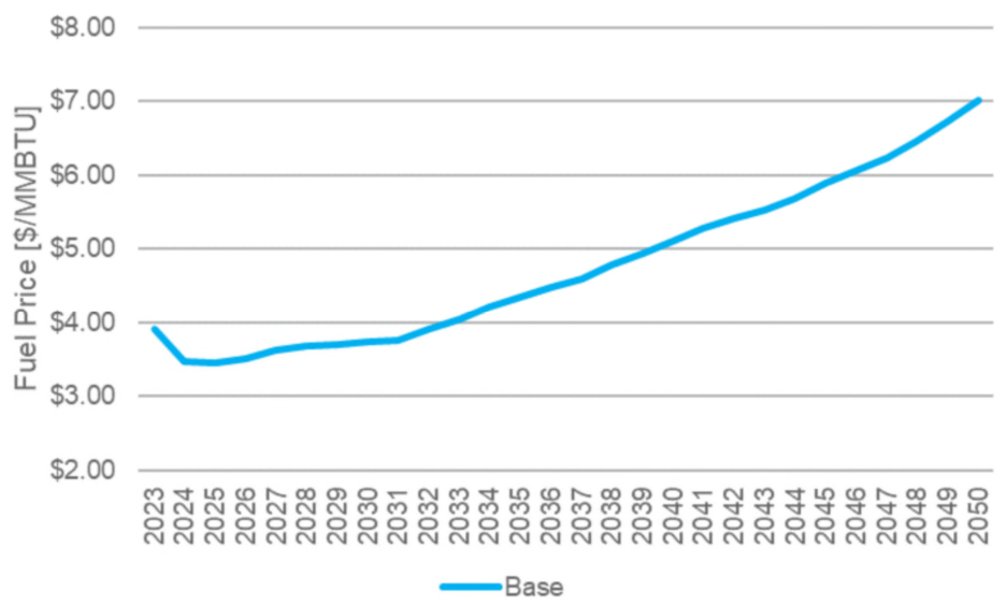
Q. HOW DO YOU RESPOND TO THOSE THAT CLAIM MORE INTERSTATE NATURAL GAS CAPACITY IS NOT NEEDED IN THE CAROLINAS?

A. The prices now paid at Zone 5 provide evidence that such claims are false and erroneous. Natural gas prices in January and February of 2023 are expected to shoot up to close to $20/MMBTU. Such prices will shock the typical North Carolinian that will struggle to pay their natural gas and electric bills this winter. Industries may not be able to operate when they are required to purchase Zone 5 gas in excess of $20/MMBTU. The North Carolina economy will, without a doubt, feel the squeeze from the ongoing constraints at Transco Zone 5.

Q. HOW DOES THE RECENT INCREASE IN NATURAL GAS COSTS IMPACT DUKE'S CARBON PLAN?

A. Chart 1 below is actually Figure E-6 from Duke's Carbon Plan that shows the Henry Hub natural gas base forecast used by Duke in its analysis.

Chart 3: Duke Base Natural Gas Price Forecast



As can be seen in the above chart, Duke's base forecast looks nothing like the costs with which we are dealing in 2022. All the factors that I have previously mentioned have combined to create a perfect storm in the natural gas markets in 2022. The unwinding of the markets may take some time. Indeed, if other countries do not step up and sell natural gas to Europe, it is possible that consumers in the United States will pay elevated prices for quite some time.

Q. DID DUKE RECOGNIZE THE ISSUE AT TRANSCO ZONE 5 WHEN IT PREPARED ITS CARBON PLAN?

A. Yes, it did. Page 42 of Appendix E of the Carbon Plan discusses the Zone 5 problem. Unfortunately, Duke did not provide a solution to the problem at Zone 5.

Q. DO YOU HAVE A RECOMMENDATION FOR THE COMMISSION TO ALLEVIATE THE NATURAL GAS CONSTRAINTS AT ZONE 5 AS PART OF ITS APPROVAL OF THE DUKE CARBON PLAN?

A. Yes. First, as the Commission is well aware, the completion of the Mountain Valley Pipeline (MVP) may bring us some relief from high prices. However, MVP may not be a permanent savior. I believe North Carolina needs Transco to expand in order for the State to continue to grow and meet its future needs. My recommendation is that, as part of its refiling of the Carbon Plan, Duke should enter into discussions with Transco, obtain an approximate cost estimate for an expansion, and work that expansion cost into the Carbon Plan portfolios. Armed with that information, I believe the Commission will be in a better position to make the best decision for our State.

IV. TRANSMISSION: PROBLEMS IN SITING NEW LINES

Q. DO YOU AGREE WITH THE TRANSMISSION COST ESTIMATES AS PUT FORWARD BY DUKE IN THE CARBON PLAN?

A. No. I believe Duke's estimates are educated guesses. While I believe that Duke did as good as a job as possible in forecasting costs for new transmission, I think they failed to account for a huge issue with new transmission: siting. A problem with new transmission is that citizens do not want transmission near their homes and businesses.

On August 20, 2022, the Wall Street Journal published an article that discussed the problems with siting new infrastructure and stated the following:

> A March Pew study found that 72% of Americans believe the federal government should encourage the development of wind and solar projects, but the infrastructure needed to support that goal often faces strong opposition at the local level out of concerns they might disfigure landscapes, endanger wildlife or threaten natural resources.
>
> "It is very hard to build infrastructure of any kind in the United States," said John Holdren, a former director of the White House Office of Science and Technology Policy under President Barack Obama who is now a Harvard University professor. "There are genuine tensions between the desire of one set of people to build stuff and the desire of the public to have a voice."
>
> Transmission lines are crucial to President Biden's goal of eliminating carbon emissions from the power grid by 2035 because they are needed to carry electricity from renewable- energy sources to the cities where most Americans live. Building a power line

> spanning several states can now take about a decade, developers said, up from five to seven years previously.[3]

The above-stated article states that building a transmission line spanning several states can now take up to 10 years to complete. Even if all the new transmission required to meet Duke's Carbon Plan is contained to North Carolina, it is unreasonable to assume that all the new transmission can be completed by 2030, which is the time period which Portfolio 1 has targeted for the 70% reduction in carbon. Indeed, given the tremendous amount of new transmission required, I find it difficult to believe that construction will be completed in time to meet even the 2035 goals as part of Portfolios 2, 3, and 4. Duke recognizes the siting issues in the Carbon Plan when, in regard to wind generation, it states:

> The schedule associated with siting, permitting and constructing this transmission is dependent on public engagement, routing, scoping and acquisition of new ROW for new 500 kV DC and 500 kV AC transmission lines that will be required to import up to 1.6 GW of wind. Delays in these schedule dependencies are key risks in meeting any timeline for importing offshore wind energy.[4]

Q. HOW DO YOU RECOMMEND DUKE ADDRESS THE VARIABILITY ASSOCIATED WITH SITING NEW TRANSMISSION?

A. In its next filing with the Commission, I recommend Duke be required to provide specific timelines for each potential new transmission line associated with meeting any of the portfolios in the Carbon Plan. Armed with this information, the Commission can view the various portfolios in terms of construction timeline risk.

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[3] Benoît Morenne, *Energy Projects Sought Across the U.S. Face Local Hurdles*, Wall Street Journal (Aug. 20, 2022), available at https://www.wsj.com/articles/energy-projects-needed-across-the-u-s-face-local-hurdles-11660968040.

[4] Duke Carbon Plan, App. P, at 7.

Such information is just one more set of data that can help inform the Commission in its efforts to make a more informed decision.

V. COST: DUKE SHOULD PRESENT ALL ANTICIPATED FUTURE COSTS AS PART OF THE CARBON PLAN

Q. DID DUKE PAINT A REALISTIC PICTURE OF ALL THE COSTS IT MAY SEEK IN FUTURE RATE CASES?

A. No, it did not. While Duke is undertaking the Carbon Plan to fundamentally change the way North Carolina receives power, it will also be undertaking other initiatives. For example, the Company has long sought approval of its grid modernization program ("GRIM"). This grid improvement program has a very expensive price tag. Indeed, Company officials have, in the past, put the price tag for GRIM as high as $13 billion. These price forecasts need to be placed into the overall cost structure associated with the Carbon Plan. Again, consumers have a right to know how much their power bills will be increasing in the future. Being silent on such key issues such as GRIM will serve to only irritate consumers when their bills go up and up and up without realizing any concurrent benefit.

Although GRIM is not part of the Carbon Plan, it is still one of the future costs that Duke is requesting consumers in North Carolina to bear. Presenting the Carbon Plan's costs as a forecast of future energy prices seems incomplete without accounting for the additional cost of GRIM. Ratepayers have a right to know all our future energy costs.

Q. DO YOU BELIEVE DUKE IS CAPABLE OF FORECASTING COST IMPACTS TO CONSUMERS?

A. Yes, absolutely. As part of HB 951, I worked with Ms. Laura Bateman from Duke in calculating the anticipated rate hikes from the Carbon Plan. I know Duke is highly capable of calculating such costs forecasts. Indeed, Duke's work in the Carbon Plan shows that its personnel can calculate all the forecasted costs. For the sake of transparency, Duke should present the annual anticipated rate hikes for the residential class, the commercial class, and the industrial class for each year out 10-years and 20-years into the future.

VI. <u>COST: DUKE SHOULD BE HELD ACCOUNTABLE FOR MEETING ITS COST FORECASTS</u>

Q. DO YOU BELIEVE THE CARBON PLAN SHOULD BE SUBJECT TO A PRUDENCE REVIEW BY THIS COMMISSION?

A. Yes. I believe that every cost put forward by Duke should be compared to the forecasted cost adjusted for inflation. To the extent that Duke's forecasts are inaccurate or the Company is proven to be somewhat lax in its construction efforts, consumers should not be penalized by excessive costs.

The hard reality of the situation in which we find ourselves is that electric rates in North Carolina will soon be shooting up to pay for all the items as noted in the Duke Carbon Plan. The pain to be faced by consumers will be real. Consumers have a right to know that Duke has done everything in its power to accurately forecast the costs and to bring those project into service at the promised cost, adjusted for inflation.

At the end of the day, the Commission, not myself or any other intervenor, will be the judge of Duke's actions. That said, we all must have faith in the process and there must be ramifications for Duke's errors or misjudgments.

VII. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY IN THIS PROCEEDING.

A. My findings and recommendations in this case are as follows:

1. Since the date of the Carbon Plan filing, energy markets have been incredibly volatile. Duke should be required to re-file the Carbon Plan with updated forecasts for natural gas and coal and to develop a solid strategy for enhancing more natural gas interstate capacity into North Carolina and report that strategy to the Commission.
2. Duke should provide specific timelines that it anticipates for completed construction for necessary transmission lines for each of its portfolios.
3. To help consumers understand, and prepare for, the magnitude of future rate hikes, Duke should outline <u>all</u>—not just carbon-related—future costs including, but not limited to, its grid investment charges.
4. The Commission should strictly enforce the prudence standard such that all Duke costs for which it seeks recovery must meet its forecasted costs adjusted by inflation.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Appendix A

Kevin O'Donnell Direct Testimony
Docket No. E-100, Sub 179

Kevin W. O'Donnell, CFA

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Kevin W. O'Donnell, is the founder of Nova Energy Consultants, Inc. in Cary, NC. Mr. O'Donnell's academic credentials include a B.S. in Civil Engineering - Construction Option from North Carolina State University as well as a MBA in Finance from Florida State University. Mr. O'Donnell is also a Chartered Financial Analyst (CFA).

Mr. O'Donnell has over thirty-four years of experience working in the electric, natural gas, and water/sewer industries. He is very active in municipal power projects and has assisted numerous southeastern U.S. municipalities cut their wholesale cost of power by as much as 67%. On Dec. 12, 1998, ***The Wilson Daily Times*** made the following statement about O'Donnell.

> **Although we were skeptical of O'Donnell's efforts at first, he has shown that he can deliver on promises to cut electrical rates.**

Mr. O'Donnell has completed close to 30 wholesale power projects for municipal and university-owned electric systems throughout North and South Carolina. In May of 1996 Mr. O'Donnell testified before the U.S. House of Representatives, Committee on Commerce, Subcommittee on Energy and Power regarding the restructuring of the electric utility industry.

Mr. O'Donnell has appeared as an expert witness in over 130 regulatory proceedings before the North Carolina Utilities Commission, the South Carolina Public Service Commission, the Virginia Corporation Commission, the Minnesota Public Service Commission, the New Jersey Board of Public Utilities, the Colorado Public Service Commission, the Wisconsin Public Service Commission, the Maryland Public Service Commission, the District of Columbia Public Service Commission, the Pennsylvania Public Utility Commission, the Indiana Public Utility Commission, the California Public Service Commission, and the Florida Public Service Commission. His area of expertise has included rate design, cost of service, rate of return, capital structure, asset valuation analyses, fuel adjustments, merger transactions, holding company applications, as well as numerous other accounting, financial, and utility rate-related issues.

Mr. O'Donnell is the author of the following two articles: "Aggregating Municipal Loads: The Future is Today" which was published in the Oct. 1, 1995 edition of *Public Utilities Fortnightly;* and "Worth the Wait, But Still at Risk" which was published in the May 1, 2000 edition of *Public Utilities Fortnightly*. Mr. O'Donnell is also the co-author of "Small Towns, Big Rate Cuts" which was published in the January, 1997 edition of *Energy Buyers Guide*. All of these articles discuss how rural electric systems can use the wholesale power markets to procure wholesale power supplies.

Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client/ Employer	Case Issues
1985	Public Service Company of NC	NC	G-5, Sub 200	Public Staff of NCUC	Return on equity, capital structure
1985	Piedmont Natural Gas Company	NC	G-9, Sub 251	Public Staff of NCUC	Return on equity, capital structure
1986	General Telephone of the South	NC	P-19, Sub 207	Public Staff of NCUC	Return on equity, capital structure
1987	Public Service Company of NC	NC	G-5, Sub 207	Public Staff of NCUC	Return on equity, capital structure
1988	Piedmont Natural Gas Company	NC	G-9, Sub 278	Public Staff of NCUC	Return on equity, capital structure
1989	Public Service Company of NC	NC	G-5, Sub 246	Public Staff of NCUC	Return on equity, capital structure
1990	North Carolina Power	NC	E-22, Sub 314	Public Staff of NCUC	Return on equity, capital structure
1991	Duke Energy	NC	E-7, Sub 487	Public Staff of NCUC	Return on equity, capital structure
1991	North Carolina Natural Gas	NC	G-21, Sub 306	Public Staff of NCUC	Natural gas expansion fund
1991	North Carolina Natural Gas	NC	G-21, Sub 307	Public Staff of NCUC	Natural gas expansion fund
1991	Penn & Southern Gas Company	NC	G-3, Sub 186	Public Staff of NCUC	Return on equity, capital structure
1995	North Carolina Natural Gas	NC	G-21, Sub 334	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1995	Carolina Power & Light Company	NC	E-2, Sub 680	Carolina Utility Customers Assoc.	Fuel adjustment proceeding
1995	Duke Power	NC	E-7, Sub 559	Carolina Utility Customers Assoc.	Fuel adjustment proceeding
1996	Piedmont Natural Gas Company	NC	G-9, Sub 378	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Piedmont Natural Gas Company	NC	G-9, Sub 382	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Public Service Company of NC	NC	G-5, Sub 356	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Cardinal Extension Company	NC	G-39, Sub 0	Carolina Utility Customers Assoc.	Capital structure, cost of capital
1997	Public Service Company of NC	NC	G-5, Sub 327	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1998	Public Service Company of NC	NC	G-5, Sub 386	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1998	Public Service Company of NC	NC	G-5, Sub 386	Carolina Utility Customers Assoc.	Natural gas transporation rates
1999	Public Service Company of NC/SCANA Corp	NC	G-5, Sub 400	Carolina Utility Customers Assoc.	Merger case
1999	Public Service Company of NC/SCANA Corp	NC	G-43	Carolina Utility Customers Assoc.	Merger Case
1999	Carolina Power & Light Company	NC	E-2, Sub 753	Carolina Utility Customers Assoc.	Holding company application
1999	Carolina Power & Light Company	NC	G-21, Sub 387	Carolina Utility Customers Assoc.	Holding company application
1999	Carolina Power & Light Company	NC	P-708, Sub 5	Carolina Utility Customers Assoc.	Holding company application
2000	Piedmont Natural Gas Company	NC	G-9, Sub 428	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2000	NUI Corporation	NC	G-3, Sub 224	Carolina Utility Customers Assoc.	Holding company application
2000	NUI Corporation/Virginia Gas Company	NC	G-3, Sub 232	Carolina Utility Customers Assoc.	Merger application
2001	Duke Power	NC	E-7, Sub 685	Carolina Utility Customers Assoc.	Emission allowances and environmental compliance costs
2001	NUI Corporation	NC	G-3, Sub 235	Carolina Utility Customers Assoc.	Tariff change request.
2001	Carolina Power & Light Company/Progress E	NC	E-2, Sub 778	Carolina Utility Customers Assoc.	Asset transfer case
2001	Duke Power	NC	E-7, Sub 694	Carolina Utility Customers Assoc.	Restructuring application
2002	Piedmont Natural Gas Company	NC	G-9, Sub 461	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2002	Cardinal Pipeline Company	NC	G-39, Sub 4	Carolina Utility Customers Assoc.	Cost of capital, capital structure
2002	South Carolina Public Service Commission	SC	2002-63-G	South Carolina Energy Users Committee	Rate of return, accounting, rate design, cost of service
2003	Piedmont Natural Gas/North Carolina Natura	NC	G-9, Sub 470	Carolina Utility Customers Assoc.	Merger application
2003	Piedmont Natural Gas/North Carolina Natura	NC	G-9, Sub 430	Carolina Utility Customers Assoc.	Merger application
2003	Piedmont Natural Gas/North Carolina Natura	NC	E-2, Sub 825	Carolina Utility Customers Assoc.	Merger application
2003	Carolina Power & Light Company	NC	E-2, Sub 833	Carolina Utility Customers Assoc.	Fuel case
2004	South Carolina Electric & Gas	SC	2004-178-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2005	Carolina Power & Light Company	NC	E-2, Sub 868	Carolina Utility Customers Assoc.	Fuel case
2005	Piedmont Natural Gas Company	NC	G-9, Sub 499	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2005	South Carolina Electric & Gas	SC	2005-2-E	South Carolina Energy Users Committee	Fuel application
2005	Carolina Power & Light Company	SC	2006-1-E	South Carolina Energy Users Committee	Fuel application
2006	IRP in North Carolina	NC	E-100, Sub 103	Carolina Utility Customers Assoc.	Submitted rebuttal testimony in investigation of IRP in NC.
2006	Piedmont Natural Gas Company	NC	G-9, Sub 519	Carolina Utility Customers Assoc.	Creditworthiness issue
2006	Public Service Company of NC	NC	G-5, Sub 481	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2006	Duke Power	NC	E-7, 751	Carolina Utility Customers Assoc.	App to share net revenues from certain wholesale pwr trans

Regulatory Cases of Kevin W. O'Donnell, CFA

Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client/ Employer	Case Issues
2006	South Carolina Electric & Gas	SC	2006-192-E	South Carolina Energy Users Committee	Fuel application
2007	Duke Power	NC	E-7, Sub 790	Carolina Utility Customers Assoc.	Application to construct generation
2007	South Carolina Electric & Gas	SC	2007-229-E	South Carolina Energy Users Committee	Rate of return, accounting, rate design, cost of service
2008	South Carolina Electric & Gas	SC	2008-196-E	South Carolina Energy Users Committee	Base load review act proceeding
2009	Western Carolina University	NC	E-35, Sub 37	Western Carolina University	Rate of return, accounting, rate design, cost of service
2009	Duke Power	NC	E-7, Sub 909	Carolina Utility Customers Assoc.	Cost of service, rate design, return on equity, capital structure
2009	South Carolina Electric & Gas	SC	2009-261-E	South Carolina Energy Users Committee	DSM/EE rate filing
2009	Duke Power	SC	2009-226-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2009	Tampa Electric	FL	080317-EI	Florida Retail Federation	Return on equity, capital structure
2010	Duke Power	SC	2010-3-E	South Carolina Energy Users Committee	Fuel application - assisted in settlement
2010	South Carolina Electric & Gas	SC	2009-489-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2010	Virginia Power	VA	PUE-2010-00006	Mead Westvaco	Rate design
2011	Duke Energy	SC	2011-20-E	South Carolina Energy Users Committee	Nuclear construction financing
2011	Northern States Power	MN	E002/GR-10-971	Xcel Large Industrials	Return on equity, capital structure
2011	Virginia Power	VA	PUE-2011-0027	Mead Westvaco	Capital structure, revenue requirement
2011	Duke Energy	NC	E-7, Sub 989	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2011	Duke Energy	SC	2011-271-E	South Carolina Energy Users Committee	Accounting, cost of service, rate design, ROE, capital structure
2011	Dominion Virginia Power	VA	PUE-2011-00073	Mead Westvaco	Rate design
2012	Town of Smithfield/Partners Equity Group	NC	ES-160, Sub 0	Partners Equity Group	Rate design, asset valuation
2012	Florida Power & Light	FL	120015-EI	Florida Office of Public Counsel	Capital structure
2012	South Carolina Electric & Gas	SC	2012-218-E	South Carolina Energy Users Committee	Accounting, cost of service, rate design, ROE, capital structure
2013	Progress Energy Carolinas	NC	E-2, Sub 1023	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2013	Duke Energy Carolinas	NC	E-7, Sub 1026	Carolina Utility Customers Assoc.	Rate design
2013	Jersey Central Power & Light	NJ	BPU ER12111052	Gerdau Ameristeel	Return on equity, capital structure
2013	Duke Energy Carolinas	SC	2013-59-E	South Carolina Energy Users Committee	Accounting, cost of service, rate design, ROE, capital structure
2013	Tampa Electric	FL	130040-EI	Florida Office of Public Counsel	Capital structure and financial integrity
2013	Piedmont Natural Gas	NC	G-9, Sub 631	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2014	Dominion Virginia Power	VA	PUE-2014-00033	Mead Westvaco	Recoverable fuel costs, hedging strategies
2014	Public Service Company of Colorado	CO	14AL-0660E	Colorado Healthcare Electric Coordinating Council	Return on equity, capital structure
2015	WEC Acquisition of Integrys	WI	9400-YO-100	Staff of Wisconsin Public Service Commission	Merger analysis
2015	Dominion Virginia Power	VA	PUE-2015-00027	Federal Executive Agencies	Return on equity
2015	South Carolina Electric & Gas	SC	2015-103-E	South Carolina Energy Users Committee	Return on equity
2015	Western Carolina University	NC	E-35, Sub 45	Western Carolina University	Accounting, cost of service, rate design, ROE, capital structure
2016	Sandpiper Energy	MD	9410	Maryland Office of People's Counsel	Return on equity, capital structure
2016	Washington Gas Light	DC	FC 1137	Washington, DC Office of People's Counsel	Return on equity, capital structure
2016	Florida Power & Light	FL	160021-EI	Florida Office of Public Counsel	Capital Structure
2016	Jersey Central Power & Light	NJ	EM15060733	NJ Division of Rate Counsel	Asset valuation
2016	Rockland Electric Company	NJ	ER16050428	NJ Division of Rate Counsel	Rate design
2016	Dominon NC Power	NC	E-22, Sub 532	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2017	Potomac Electric Power	DC	FC 1139	Healthcare Council of the National Capitol Area (HCNCA)	ROE and capital structure
2017	Columbia Gas of Maryland	MD	FC 9447	Maryland Office of People's Counsel	ROE and capital structure
2017	Washington Gas Light	DC	FC 1142	Washington, DC Office of People's Counsel	Merger analysis
2017	Duke Energy Progress	NC	E-2, Sub 1142	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2018	Public Service Electric & Gas	NJ	GR17070776	NJ Division of Rate Counsel	ROE and capital structure
2018	Duke Energy Carolinas	NC	E-7, Sub 1146	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2018	Elkton Gas/SJI	MD	FC 9475	Maryland Office of People's Counsel	Merger analysis
2018	Entergy Texas	TX	PUC 48371	Entergy Texas Cities	ROE
2018	Duke Energy Carolinas	SC	2018-3-E	South Carolina Energy Users Committee	Fuel case

Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jursisdiction	Docket No.	Client/ Employer	Case Issues
2018	Elkton Gas Company	MD	FC 9488	Maryland Office of People's Counsel	Accounting, ROE, capital structure
2018	Baltimore Gas & Electric	MD	FC9484	Maryland Office of People's Counsel	ROE, capital structure
2018	South Carolina Electric & Gas	SC	2017-370-E	South Carolina Energy Users Committee	Creditworthiness issue
2018	Jersey Central Power & Light	NJ	EO18070728	NJ Division of Rate Counsel	ROE and capital structure
2019	Duke Energy Carolinas	SC	2018-319-E	South Carolina Energy Users Committee	Accounting, rate design
2019	Duke Energy Progress	SC	2018-318-E	South Carolina Energy Users Committee	Accounting, rate design
2019	Public Service Electric and Gas	NJ	EO18060629	NJ Division of Rate Counsel	ROE and capital structure
2019	Potomac Electric Power	MD	FC 9602	Maryland Office of People's Counsel	ROE, capital structure
2019	Oklahoma Gas and Electric	OK	PUD 201800140	Sierra Club	Creditworthiness issue
2019	Peoples Natural Gas	PA	R-2018-3006818	Pennsylvania Office of Consumer Advocate	ROE, capital structure
2019	UGI Natural Gas	PA	R-2018-3006814	Pennsylvania Office of Consumer Advocate	ROE, capital structure
2019	Dominion Virginia Power	VA	PUR-2019-00050	Federal Executive Agencies	Return on Equity
2019	Piedmont Natural Gas	NC	G-9, Sub 743	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE
2019	Pacific Gas & Electric, Southern California Edison, San Diego Gas & Electric	CA	A-1904014, et al	Federal Executive Agencies	ROE, capital structure
2019	Duke Energy Indiana	IN	Cause 45253	Federal Executive Agencies	ROE, capital structure
2020	Duke Energy Carolinas	NC	E-7 Sub 1214	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE
2020	Duke Energy Progress	NC	E-2 Sub 1219	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE
2020	Dominion Virginia Power	VA	PUR-2019-00154	Southern Environmental Law Center	Financial analysis of plant investment
2020	Southwest Electric Power Company	LA	U-35324	Alliance for Affordable Energy	Financial analysis of plant investment
2020	Texas Gas Company	TX	PUC 10928	Texas Gas Cities	ROE, capital structure
2020	Potomac Electric Power	DC	FC 1156	District of Columbia Office of Peoples Counsel	ROE, capital structure
2020	UGI Gas	PA	R-2019-3015162	Pennsylvania Office of Consumer Advocate	ROE, capital structure, creditworthiness
2020	Columbia Gas of Maryland	MD	FC 9644	Maryland Office of People's Counsel	ROE, capital structure
2020	Columbia Gas of Pennsylvania	PA	R-2020-3018835	Pennsylvania Office of Consumer Advocate	ROE, capital structure
2020	New Mexico Gas Company	NM	19-00317-UT	Federal Executive Agencies	ROE, capital structure, accounting, rate design, cost of service
2020	Washington Gas Light	DC	FC 1162	District of Columbia Office of Peoples Counsel	ROE, capital structure
2020	Dominion Energy South Carolina	SC	2020-125-E	South Carolina Energy Users Committee	Accounting, rate design
2021	Suez Water Company	NJ	BPU WR2011	NJ Division of Rate Counsel	ROE, capital structure, rate design
2021	Columbia Gas of Pennsylvania	PA	R-2021-3024296	Pennsylvania Office of Consumer Advocate	ROE, capital structure
2021	Florida Power & Light	FL	20210015-EI	Florida Office of Public Counsel	Capital structure, financial rate analysis
2021	Piedmont Natural Gas Company	NC	G-9 Sub 781	Carolina Utility Customers Assoc.	Rate of return, cost of service, rate design
2021	Dominion Virginia Power	VA	PUR-2021-00058	Federal Executive Agencies	ROE, capital structure
2021	Public Service Company of NC	NC	G-5 Sub 632	Carolina Utility Customers Assoc.	Rate of return, cost of service, rate design
2022	Entergy Texas	TX	52487	Texas Gas Cities	Generation plant feasibility analysis
2022	New Mexico Gas Company	NM	21-00267-UT	Federal Executive Agencies	ROE, capital structure, accounting, rate design, cost of service
2022	Piedmont Natural Ga	SC	2022-89-G	South Carolina Energy Users Committee	Cost of Service Studies, rate design

Summary of Testimony of Kevin O'Donnell
on behalf of the Carolina Utility Customers Association

The purpose of my testimony is to highlight the key concerns I have with the assumptions upon which Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (collectively, "Duke" or the "Companies") relied for developing their Carbon Plan. First, with the cancellation of the Atlantic Coast Pipeline, our State now faces a huge problem with obtaining natural gas in the future at reasonable prices and on a firm basis. Without offering any solution for this problem, Duke seeks to build more gas plants. While I am not opposed to the construction of gas plants in general, I am deeply troubled by Duke's commitment to build natural gas resources in the near-term *without any concrete plan for securing a firm fuel supply for those resources*. Second, Duke did not address the practical challenges of constructing new transmission lines. Society is increasingly opposed to new infrastructure projects, and Duke has not accounted for these challenges in its modeling. Third, I believe Duke should provide an "all-in" bill-impact analysis that includes the anticipated costs of the Carbon Plan as well as Duke's other initiatives such as grid modernization costs. The Commission and ratepayers need to understand the total costs of Duke's future plans before we start to head down a Carbon Plan pathway.

Thank you for your time.

MR. SCHAUER: Witness is available for questions.

MS. CRESS: Chair Mitchell, counsel for Walmart had to step away, but CIGFUR does have a couple of questions for Witness O'Donnell if you are amenable.

CHAIR MITCHELL: You may go ahead, Ms. Cress.

MS. CRESS: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MS. CRESS:

Q. Mr. O'Donnell, you testify on page 11 of your testimony -- and I'll give you a second to get there.

A. Okay.

Q. You testify on page 11 of your testimony that the completion of the Mountain Valley Pipeline may bring us some relief from high natural gas prices; is that right?

A. Yes.

Q. And you also recommend that Duke enter into discussions with Transco and obtain an approximate cost estimate for a Transco expansion that can then be incorporated into Carbon Plan portfolios; is that right?

A. Yes.

Q. And you state that, quote, armed with that information, I believe the Commission will be in a better position to make the best decision for our state; is that right?

A. Yes.

Q. Thank you. No further questions.

CHAIR MITCHELL: All right. Any additional questions for the witness?

(No response.)

CHAIR MITCHELL: I'll take redirect for the witness.

MR. SCHAUER: No questions.

CHAIR MITCHELL: Okay. Questions from Commissioners for Mr. O'Donnell?

(No response.)

CHAIR MITCHELL: All right, Mr. O'Donnell, that was a quick one. A record for this proceeding. You may step down, sir. Thank you for your testimony.

Mr. Schauer, you have a motion for the witness?

MR. SCHAUER: I don't believe I do. He did not have any exhibits.

CHAIR MITCHELL: Thank you. All right.

Attorney General's Office, you may call your witness.

MR. MOORE: Thank you, Chair Mitchell. The North Carolina Attorney General's Office would call Edward Burgess to the stand.

CHAIR MITCHELL: All right. Mr. Burgess, do you prefer to swear or affirm?

THE WITNESS: I'll swear.

Whereupon,

EDWARD BURGESS,

having first been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION BY MR. MOORE.

Q. Mr. Burgess, would you state your name, title, and business address for the record?

A. Yes. My name is Edward Burgess. I'm a senior director at Strategen Consulting. My business address is 10265 Rockingham Drive, Sacramento, California.

Q. On September 9, 2022, did you cause to be prefiled in this docket, direct testimony consisting of 99 pages as well as five exhibits?

A. Yes, I did.

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

A. No, I do not.

Q. If I were to ask you the same questions here today, would you have the same answers?

A. Yes.

Q. On September 23rd, did you cause to be prefiled a summary of your testimony?

A. Yes.

Q. Were you also the principal author of a report titled "Analysis of Duke Energy 2022 Carbon Plan" consisting of 49 pages which was filed as Attachment 1 to the Attorney General's initial comments filed on July 15th in this docket?

A. Yes, I was.

MR. MOORE: Chair Mitchell, I would move that Mr. Burgess' prefiled direct testimony and summary be entered into the record in this proceeding as if given orally from the stand.

CHAIR MITCHELL: All right. That motion is allowed.

(Whereupon, the prefiled direct testimony of Edward Burgess and prefiled summary testimony of Edward Burgess 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**
Duke Energy Progress, LLC,	)	**EDWARD BURGESS**
and Duke Energy Carolinas,	)	**ON BEHALF OF**
LLC, 2022 Biennial	)	**ATTORNEY GENERAL'S**
Integrated Resource Plans and	)	**OFFICE**
Carbon Plan	)	

Contents

I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Edward Burgess. My business address is Strategen Consulting ("Strategen"), 10265 Rockingham Dr., Suite #100-4061, Sacramento, CA 95827.

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

A. I am the Senior Director of Integrated Resource Planning with Strategen.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I am a leader on Strategen's consulting team and oversee much of the firm's utility-focused practice for governmental clients, non-governmental organizations, and trade associations. Strategen's team is globally recognized for its expertise in the electric and gas utility sectors on issues relating to resource planning, transmission planning, renewable energy, energy storage, rate design, cost of service, program design, and utility business models and strategy. During my time at Strategen, I have managed or supported projects for numerous client engagements related to these issues. Before joining Strategen in 2015, I worked as an independent consultant in Arizona and regularly appeared before the Arizona Corporation Commission. I also worked for Arizona State University where I helped launch their Utility of the Future initiative as well as the Energy Policy Innovation Council. I have a Professional Science Master's degree in Solar Energy Engineering and Commercialization from Arizona State University as well as a Master of Science in Sustainability, also from Arizona State. I also have a Bachelor of Arts degree in Chemistry from Princeton University. A full resume is attached as Exhibit 1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the North Carolina Attorney General's Office ("AGO").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No. However, I have provided technical support to the Attorney General's Office on several recent proceedings including Duke's 2018 and 2020 Integrated Resource Plans. I have also presented at the October 2021 Technical Workshop on Duke's 2020 Integrated Resource Plan.

Q. HAVE YOU EVER TESTIFIED BEFORE ANY OTHER STATE REGULATORY BODY?

A. Yes. I have testified before the California Public Utilities Commission (Docket Nos. A.19-08-002, A.20-08-002, R.20-11-003, A.21-08-004, A.21-10-010, and A.21-10-011), the Oregon Public Utilities Commission (Docket Nos. UE-375, UE-390, and UG-435), the Indiana Utility Regulatory Commission (Cause Nos. 38707 FAC 123 S1 and 38707 FAC 125), the Louisiana Public Service Commission (Docket No. U-36105), the Massachusetts Department of Public Utilities (D.P.U. 18-150 and D.P.U. 17-140), the Michigan Public Service Commission (Docket No. U-21090), the Nevada Public Utilities Commission (Docket No. 20-07023), the South Carolina Public Service Commission (Docket Nos. 2019-186-E, 2019-185-E, 2019-184-E, and 2021-88-E), and the

Washington Utilities and Transportation Commission (Docket Nos. UE-200900 and in UE-220053/UG-220054, UE-220066/UG-220067). Additionally, I have represented numerous clients by drafting written comments, presenting oral comments and participating in technical workshops on a wide range of proceedings at utilities commissions in Arizona, California, District of Columbia, Maryland, Minnesota, Nevada, New Hampshire, New York, North Carolina, Ohio, Oregon, Pennsylvania, at the Federal Energy Regulatory Commission, and at the California Independent System Operator.

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

A. The purpose of my Direct Testimony is to address the proposed Carbon Plan Duke Energy Progress, LLC ("DEP") and Duke Energy Carolinas, LLC ("DEC," together with DEP, "Duke").

Q. WERE YOU INVOLVED IN THE PREPARATION OF THE STRATEGEN REPORT THAT WAS INCLUDED AS PART OF THE AGO'S JULY 15TH FILING?

A. Yes. I was the principal author of the Strategen report. I affirm the accuracy and truthfulness of that report and incorporate its contents by reference as part of my testimony.

II. TESTIMONY SUMMARY

A. The AGO's proposed Carbon Plan portfolio ("SP-AGO") represents a balanced approach, that minimizes risks and uncertainties.

Q. GIVEN THE COMPLEXITY OF THIS CASE, HOW SHOULD THE COMMISSION APPROACH ITS DECISION TO ADOPTING A CARBON PLAN?

A. At the outset, it should be acknowledged that the Commission's task of adopting a Carbon Plan is not a simple one. I have had extensive experience in resource planning cases at utility commissions around the country and have seldom seen such a large volume of complex technical analysis conducted by numerous parties. Even in similarly complex cases, the timeframe for rendering a decision was never as compressed as it is here. Given these circumstances, the Commission may be tempted to select one of Duke's Supplemental Portfolios as a sort of "off the shelf" plan representing a "middle ground" between what Duke originally proposed, and some of the concerns raised by Public Staff. However, it is important for the Commission to recognize that the Supplemental Portfolios are not exactly a middle ground since they fail to address important concerns raised by other parties, including the AGO. In particular, the Supplemental Portfolios do not attempt to achieve a seventy percent (70%) reduction in emissions of carbon dioxide from Duke's North Carolina power plants from 2005 levels by 2030. Moreover, they are not reflective of the new reality under the Inflation Reduction Act. As such, while the Supplemental Portfolios contain some improvements over Duke's initial portfolios, the Commission should still make further improvements in its final decision.

Q. DOES THE AGO'S PROPOSED CARBON PLAN PORTFOLIO REFLECT AN IMPROVEMENT OVER THE SUPPLEMENTAL PORTFOLIOS (I.E., SP5 AND SP6)?

A. Yes. At the AGO's request, Strategen conducted modeling in EnCompass to develop an additional Supplemental Portfolio ("SP-AGO"). The starting point for this analysis was Duke's SP5 portfolio. SP-AGO builds upon SP5 by making improvements to a limited number of input assumptions. These improvements reflect several of the outstanding concerns raised by AGO and other parties, but which were not addressed by Duke or Public Staff in the SP5 and SP6 portfolios.

Q. WAS THE SP-AGO PORTFOLIO DESCRIBED IN THE AGO'S INITIAL COMMENTS OR THE STRATEGEN REPORT WHICH WERE BOTH FILED ON JULY 15, 2022?

A. No. The analysis supporting the SP-AGO portfolio was conducted after those comments and report were filed and after Duke's testimony was filed on August 19, 2022. Below is a timeline of the events leading up to the development of the SP-AGO portfolio:

- May 16, 2022: Duke filed its proposed Carbon Plan with four Initial Portfolios, (P1-P4) and four Alternate Fuel Portfolios (P1A-P4A)
- July 15, 2022: Intervenor comments filed. AGO/Strategen provides numerous recommendations to improve inputs and assumptions used in Duke's Initial Portfolios. Modeling/analysis of alternative portfolios

provided by CPSA/Brattle, NCSEA/Synapse, and Tech Customers/Gabel.

- Late July – Early August: Duke worked with Public Staff to identify modified input assumptions for four Supplemental Portfolios (SP5, SP6, SP5A and SP6A). Some of AGO's recommended improvements were reflected in these Supplemental Portfolios, but many were not. Table 3 provides an overview of which recommended improvements were omitted.
- August 19, 2022: Duke filed testimony with findings from Supplemental Portfolios.
- August 22 – September 2: AGO/Strategen conducted additional modeling of Supplemental Portfolios (using inputs from SP5 as starting point).
- September 3, 2022: AGO filed testimony (this document) with results of modified Supplemental Portfolio (SP-AGO), containing the remainder of AGO's recommended improvements.

Section IV-F and Exhibit 2 of this testimony provide more details on the SP-AGO modeling.

Q. DO YOU BELIEVE THE SP-AGO PORTFOLIO REPRESENTS A SENSIBLE AND BALANCED APPROACH?

A. Yes. As mentioned above, the SP-AGO portfolio builds upon the SP5 Supplemental Portfolio, which contains a few improvements over P1-P4. SP-AGO further develops SP5 by addressing some of the other key concerns the

AGO had raised. It also balances many of the interests and concerns raised by other parties in this case, not just Public Staff. Some of the key features of the SP-AGO portfolio include the following:

- Continues to pursue solar, onshore wind, and battery storage as "no regrets" near-term additions.
- Includes an ambitious—but achievable—level of near-term solar deployment (i.e., midpoint between high and low cases).
- Avoids a "rush to judgment" on the need for new gas units in light of uncertainties around fuel supply and competitiveness under the IRA.
- Maximizes competition by allowing selection of valuable resource options that were initially overlooked (e.g., 100% gas conversion at Belews Creek, alternative solar plus storage configurations, alternative wind import options).
- Maintains a "safety valve" or fallback option for meeting House Bill 951 ("HB951") compliance if there are unforeseen delays (i.e., 2030 set as initial deadline, with option to postpone at a later date).

Given these advantages, I recommend the Commission adopt the SP-AGO portfolio as its selected Carbon Plan. Furthermore, I recommend the Commission only approve the near-term actions associated with this plan that can be considered "no regrets," recognizing that more analysis is needed in light of the IRA.

B. Key Conclusions and Recommendations

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. My conclusions and recommendations are as follows:

1. The passage of the Inflation Reduction Act ("IRA") is a significant and material change to key planning assumptions which are likely to affect the results of any Carbon Plan portfolio analysis, as well as certain near-term actions. While near-term procurement of solar, wind, and battery storage will be further cemented as "no regrets" options, the reasonableness of procuring new gas resources (especially CC additions) should be re-evaluated in the context of the IRA. This re-evaluation needs to be performed prior to consideration of an application for a Certificate of Public Convenience and Necessity ("CPCN") to construct such facilities.
2. While recognizing that analysis of the IRA is still needed, the Commission should adopt the AGO's SP-AGO portfolio as an interim measure. At a minimum, the Commission should reject any portfolio that does not incorporate specific modeling changes recommended in the AGO's initial comments, which are included in the SP-AGO portfolio such as:
    - Eliminate or significantly relax the constraints identified below in Section IV-A, including modeling constraints for solar, solar plus storage, onshore wind, and natural gas;
    - Use the alternative approaches described in Section IV-B in order to minimize out-of-model adjustment steps;

- Adjust assumptions for new natural gas resources as discussed in Section IV-C, including those related to plant book life, uncertainties around lack of firm transport for gas supply, and the uncertain feasibility of hydrogen conversion.

3. The Commission should approve the "no regrets" procurement of solar, onshore wind, and battery resources as proposed in Duke's near-term action plan.
4. The Commission should defer approval of new natural gas additions (especially CC additions) until an updated Carbon Plan can be developed that include the changes described above (items 1 and 2). The Commission should require Duke to include the resulting portfolio as supporting analysis in any CPCN applications for near-term resource additions.
5. The Commission should defer a decision on cost recovery of long-lead time resources until a future proceeding. In doing so, the Commission should allow Duke to pursue development of these resource additions. However, additional caution should be applied to SMRs.
6. The Commission should require Duke to develop additional contingency plan scenarios that meet HB951's requirements under a high natural gas price forecast.
7. The Commission should direct Duke to include high capacity factor solar plus storage resources in its near-term solicitations as a means to more efficiently use limited transmission interconnection space.

8. The Commission should direct Duke to conduct a near-term solicitation for onshore wind to test market readiness with a target in-service date in the 2026-2027 timeframe. This solicitation should allow for wind imports with non-firm transmission. Both the wind and solar procurements mentioned above should seek to maximize competition through third party providers.
9. The Commission should direct Duke to pursue deployment of battery storage at the Marshall and Mayo plants as a means to achieve more economic early retirement dates in the 2027-2028 timeframe, while avoiding the need for additional transmission upgrades. These deployments should seek to leverage new DOE financing options under the IRA.
10. The Commission should require Duke to employ strategies that minimize execution risk of renewable resources including:
    a. Pursuing additional solar plus storage configurations with higher capacity factors that can reduce needed interconnection space.
    b. Pursuing additional wind options including imports with non-firm transmission.
    c. Increasing opportunities for distributed resources.
    d. Siting facilities at or near retiring coal plants to minimize transmission constraints.
    e. Investing in grid-enhancing technologies to increase interconnection limits.

f. Identifying low-cost, incremental transmission improvements following larger upgrades that can unlock greater interconnection potential.

11. Prior to any future Carbon Plan filings, the Commission should order Duke to provide information on the feasibility and cost of retiring Belews Creek from coal by 2030 and operating the plant on 100% natural gas.

12. In future Carbon Plan filings, the Commission should order Duke to:

- Minimize the number of out-of-model adjustments in future iterations of the Carbon Plan and to provide full transparency on specific resource additions made through any out-of-model adjustments and the reason for those adjustments (e.g., reliability-based adjustments);
- Minimize the number of resource-specific model constraints;
- Include the Belews Creek 100% gas conversion option for the model to select;
- Include Energy Efficiency ("EE")/Demand-Side Management ("DSM") and distributed solar as a selectable resources;
- Evaluate the costs and benefits of different levels of EE/DSM and rooftop solar deployment by varying the level of incentives provided;
- Ensure that the forecast is not overly inflated by revising the method for including Utility Energy Efficiency ("UEE") roll-off in its load forecast relative to "naturally occurring" efficiency.

13. In a future proceeding, the Commission should re-evaluate the current cost-benefit analysis for EE/DSM (*i.e.*, the Utility Cost Test) to reflect currently

proposed carbon-free resources (*e.g.*, Small Modular Reactors ["SMRs"], Offshore Wind ["OSW"]) as the alternative to the traditionally used proxy resources (*e.g.*, Combustion Turbines ["CTs"]).

14. The Commission should reject Duke's proposal to move to an "as-found" EE/DSM baseline and instead maintain the current approach to counting EE savings, using the minimum federal efficiency and performance requirements as the baseline.

III. THE INFLATION REDUCTION ACT

A. The Inflation Reduction Act materially changes many key planning assumptions used by Duke and other parties.

Q. HAVE THERE BEEN ANY SIGNIFICANT FEDERAL POLICY CHANGES SINCE STRATEGEN'S REPORT WAS SUBMITTED TO THE COMMISSION ON JULY 15TH?

A. Yes. On August 16th, 2022, the Inflation Reduction Act ("IRA") was signed into law by President Biden. At the time of Strategen's July 15th report, it was not clear if any federal energy legislation would pass through Congress any time soon, let alone what provisions would be included. However, the recently enacted IRA is one of the most significant pieces of federal energy legislation in recent decades and will likely have transformational effects on energy investments made over the next decade.

Q. WOULD THE CHANGES MADE UNDER THE IRA HAVE A SIGNIFICANT IMPACT ON THE INPUTS AND ASSUMPTIONS USED

BY DUKE AND OTHER PARTIES IN THEIR ANALYSIS OF THE CARBON PLAN?

A. Yes. To put it bluntly, the previous analysis was performed using assumptions that are now obsolete and do not reflect the current reality. As such, the previously proposed portfolios likely differ in meaningful ways from the optimal path forward under the IRA. In an ideal world, a major federal policy change like this would be a moment to "hit pause" and give parties additional time to reevaluate what resources the preferred Carbon Plan portfolio should include. A complete reevaluation may not be feasible given the short timeframe the Commission has to render a decision on this matter under HB951 and the significant amount of time and effort already put into this proceeding by many parties. But given the significance of the IRA, the Commission should make every effort to take it into account.

Q. DID DUKE'S SUPPLEMENTAL PORTFOLIO ANALYSIS (I.E., SP5 AND SP6) FILED IN ITS AUGUST 19, 2022 TESTIMONY INCORPORATE THE EFFECTS OF THE IRA?

A. No. To my knowledge, no comprehensive analysis of a Carbon Plan portfolio has been completed by Duke or any other stakeholder that includes the effects of the IRA.

Q. EVEN THOUGH NO UPDATED PORTFOLIO MODELING HAS BEEN PERFORMED YET, HOW DO YOU EXPECT THE IRA WILL INFLUENCE THE OPTIMAL CARBON PLAN PORTFOLIO IN THE

NEAR TERM (I.E., THROUGH 2030), INCLUDING DUKE'S PROPOSED NEAR-TERM ACTIONS?

A. I expect that if the IRA assumptions were incorporated, it would very likely increase the economic selection of wind, solar, and (especially) battery storage resources. Meanwhile, it would likely decrease the economic selection of natural gas due to reduced competitiveness. The IRA might cause nuclear and hydrogen to become more cost-effective over the long-term, but as Duke and other parties have acknowledged, these technologies are still being developed and aren't expected to be available until the 2030s. The IRA could also accelerate replacement of coal plants with new generation through the availability of low-cost financing offered through the DOE's Loan Program Office.[1]

B. The Carbon Plan will not be informative in future CPCN proceedings if it is developed without analysis of the IRA.

Q. WOULD YOU HAVE ANY CONCERNS IF THE COMMISSION WERE TO APPROVE A CARBON PLAN THAT DID NOT FULLY ANALYZE THE EFFECTS OF THE IRA?

A. Yes. I am particularly concerned about the possibility that the Commission might approve a Carbon Plan based on analysis without the effects of the IRA, and that this approval would later be used to inform a determination of need in future CPCN proceedings. This is especially true if Duke succeeds in its

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[1] Also known as Section 1706, see: https://crsreports.congress.gov/product/pdf/IN/IN11984.

position that the Carbon Plan should provide *a de facto* determination of need as is suggested in Duke's statement that, "to the extent the Commission selects a resource as part of an approved Carbon Plan, the Commission's Carbon Plan ruling should be controlling in a CPCN proceeding absent a material change in the facts and circumstances from the Carbon Plan assumptions."[2]

Q. DOES THE IRA CONSTITUTE A "MATERIAL CHANGE IN THE FACTS AND CIRCUMSTANCES FROM THE CARBON PLAN ASSUMPTIONS" THAT DUKE USED IN BOTH ITS INITIAL MAY 2022 AND SUPPLEMENTAL AUGUST 2022 ANALYSIS?

A. Yes, it is a material change. Thus, even under Duke's position, approval of a Carbon Plan without addressing these material changes should ***not*** be controlling in a CPCN proceeding.

IV. MODELING—METHODOLOGY

Q. WHAT ARE YOUR KEY RECOMMENDATIONS REGARDING DUKE'S MODELING METHODOLOGY?

A. Duke's use of EnCompass, an objective modeling software, represents an improvement over past resource planning efforts. However, I have two key concerns with Duke's modeling efforts. First, Duke placed a large number of unnecessary constraints on certain resource types. Second, Duke performed a number of "out-of-model" steps rather than relying on EnCompass's capabilities. Combined, these concerns have the potential to inject subjectivity into the modeling and may not have resulted in the least-cost mix of resources.

[2] Duke Energy Response to PS Data Request ("DR") 11-2(a).

Therefore, I recommend that the Commission reject any portfolio that contains these flaws. This section of my testimony focuses primarily on Duke's initially proposed Carbon Plan portfolios (i.e., P1-P4). However, I also address the changes made in Duke's Supplemental Portfolios (SP5 and SP6).

Q. WHAT ARE SOME OF THE KEY MODELING INPUTS AND ASSUMPTIONS THAT WOULD BE AFFECTED BY THE IRA?

A. Below is a table summarizing a partial set of the key model inputs that would need to be changed in the analysis presented by Duke and other parties to accurately reflect current law under the Inflation Reduction Act:

Table 1

Model Assumptions	IRA Changes	Carbon Plan Implications
Cost of wind and solar	• Extends Investment Tax Credit ("ITC") and Production Tax Credit ("PTC") for 10 years. • Manufacturing production credits may help reduce costs and/or alleviate supply chain issues.	• Significantly reduces cost of wind and solar from 2023-2032 from previous assumptions (i.e., on the order of 20% or more).
Cost of battery storage	• Allows standalone storage to claim ITC without pairing with solar (extends for 10 years). • Manufacturing production credits may help reduce costs and/or alleviate supply chain issues.	• Significantly reduces cost of battery storage from previous assumptions (i.e., on the order of 30% or more). • Eliminates dispatch limits for hybrid resources.
Cost of other clean electricity resources	• Electricity generated from nuclear and green hydrogen ("H2") power plants can also claim an ITC/PTC (starting 2025).	• Significantly reduces cost of nuclear and green hydrogen resources.

Cost of green hydrogen fuel	• Facilities that produce clean H2 are eligible for tax credits.	• Significantly reduces cost of green hydrogen fuel.
Load forecast and demand side resources	• Tax credits for electric vehicles ("EVs"). • Tax credits for EV chargers. • Tax credits for residential solar and batteries. • Tax credits for energy efficiency improvements and home energy audits. • Rebates for home retrofits, efficient electric appliances. • Local aid for advanced building codes.	• Decrease in load forecast due to accelerated efficiency improvements and distributed solar. • Increase in load forecast due to accelerated adoption of EVs and electric appliances.
Long lead-time resources (*e.g.*, SMR, OSW)	• Department of Energy (DOE) Loan Program Office lending option.	• Could reduce the financing cost of new SMR and OSW projects.
Coal/Gas Retirements	• DOE funding to support projects that invest in retired generation[3]	• Could reduce the cost of projects replacing retired coal plants.

Q. ARE THERE ANY RESOURCES IN DUKE'S PROPOSED CARBON PLAN FOR WHICH THE IRA DOES NOT PROVIDE A MEANINGFUL CHANGE?

A. Yes. New natural gas plants and related pipeline projects won't receive any direct financial benefits. It is possible that new gas plants could receive a tax credit if they include carbon capture and sequestration ("CCS"). However, I am

[3] Michael O'Boyle, Inflation Reduction Act Benefits: Billions In Just Transition Funding For Coal Communities (Aug. 24, 2022), https://www.forbes.com/sites/energyinnovation/2022/08/24/inflation-reduction-act-benefits-billions-in-just-transition-funding-for-coal-communities/?sh=688779156ebd.

skeptical that CCS investments will be economic for new gas plants, even with the provisions included in the IRA. Additionally, the IRA introduces a new charge on methane emissions in the upstream oil and gas industry which could potentially increase costs for gas suppliers who are unable to control methane leaks and flaring.[4] Thus, the passage of the IRA appears to have significantly reduced the competitiveness of new natural gas resources relative to nearly all other resources being considered in the Carbon Plan.

A. Duke's Initial Portfolio modeling (i.e., P1-P4) included several arbitrary and unreasonable constraints on potential resource options. Some, but not all, of these constraints were addressed in the Supplemental Portfolios (i.e., SP5 and SP6).

Q. WHAT CONSTRAINTS DID YOU IDENTIFY IN DUKE'S INITIAL MODELING?

A. Duke's modeling included an extensive number of resource-specific planning constraints for certain resource types. While it is typical to have some constraints, I am concerned that some of these resource-specific limits appear to be somewhat arbitrary and overly restrictive.

Q. WHAT MODELING CONSTRAINTS DO YOU BELIEVE ARE ARBITRARY AND UNREASONABLE?

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[4] Inflation Reduction Act Methane Emissions Charge: In Brief, Congressional Research Service (Aug. 29, 2022), https://crsreports.congress.gov/product/pdf/R/R47206.

A. While more details are provided in the Strategen Report,[5] Duke's Initial Portfolios (P1-P4) included the following:

- First, Duke set limits on the amount of annual solar interconnection. For example, Portfolio 1 included a limit of 1,800 MW after 2028, whereas the remaining portfolios included a limit of 1,350 MW after 2028.
- Second, Duke set cumulative limits for certain solar plus storage additions. The limit was set for 50% Battery Ratio solar plus storage resources at 450 MW in the DEC territory and 750 MW in the DEP territory.[6]
- Third, Duke limited the configurations of solar plus storage that the model could select.
- Fourth, Duke set an annual limit for additions of onshore wind. This limit was set at combined 300 MW for both DEC and DEP.[7]
- Fifth, Duke set cumulative limits for onshore wind additions. The limit was set at 600 MW for DEC and 1,200 MW for DEP.
- Sixth, Duke delayed the first year that the model could select both solar and onshore wind additions. For solar, the model was constrained from adding solar until 2027. For wind, the model was constrained from adding wind until 2029.
- Finally, Duke set constraints on the types of natural gas combined cycle units that the model could select. When conducting its base fuel supply

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[5] *See* Strategen Report, p. 6-7.
[6] *See* Strategen Report, p. 19-20.
[7] *See* Strategen Report, p. 20-22.

case analysis, Duke restricted EnCompass such that "only 1200 MW CC resources were allowed to be selected."[8]

Q. WERE ANY OF THESE CONSTRAINTS RELAXED OR REMOVED IN DUKE'S SUPPLEMENTAL PORTFOLIOS?

A. Yes, but only for two of those mentioned above. Specifically, Duke included one additional solar plus storage configuration and also allowed multiple types of combined cycle units to be selected. Table 2 below describes these changes in more detail.

Q. WHAT IMPACT DID THESE ARBITRARY CONSTRAINTS HAVE ON THE MODELING RESULTS?

A. Taken together, these limits likely play a significant role in shaping the final portfolio results, especially in the near-term. By definition, when constraints become limiting factors in the model's resource selections (*i.e.*, they are "binding constraints"), the portfolio results will be higher in cost than if the constraints were relaxed or removed. This is because the binding constraints prevent the model from selecting the least-cost resources, and instead force the model to select more expensive resources in order to stay within the constraints.

Q. WHICH OF THE CONSTRAINTS THAT YOU IDENTIFIED WERE BINDING IN DUKE'S MODELING?

A. All of the constraints that I have identified above were binding in Duke's modeling. This means that the model likely would have selected more of each if it were allowed to do so. When a modeling constraint is binding, it is even

[8] Duke Energy Response to Public Staff DR 10-2.

more important to examine that constraint to ensure that the model is not being forced to make uneconomic decisions.

Q. WHAT WOULD BE A MORE REASONABLE APPROACH FOR ANNUAL SOLAR INTERCONNECTION LIMITS?

A. Duke is grappling with real technical limitations on how much solar can realistically be interconnected each year. However, Duke has not provided sufficient justification for its assumed solar interconnection limit. In fact, Duke acknowledged that the Companies "do not have specific underlying calculations for the annual selection constraints" and that the constraints "are based on engineering judgement and transmission planning experience."[9]

According to the Clean Power Suppliers Association ("CPSA"), Duke's annual solar interconnection limit of 750 MW for 2022-2026 is approximately the same as the amount of solar that Duke reports having interconnected in 2015 and 2017, meaning that Duke assumes it will not make any improvements in its ability to interconnect new solar projects until 2027.[10] However, as CPSA also notes, there are several reasons to expect interconnection rates to improve in the near term.[11] Given this, I recommend increasing the limitations on solar additions above what Duke initially proposed. Specifically, I recommend the limit be set at the midpoint of Duke's Initial P1 portfolio and "High Solar

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[9] Duke Energy Response to NCSEA-SACE DR 3-30.
[10] CPSA Comments, p. 15
[11] CPSA Comments, p 15-19.

Interconnection" sensitivity of the Supplemental Portfolios and advanced by one year. The specific levels are shown in the table below:

Table 2

Year[12]	MW
2027	1125
2028	1275
2029	1800
2030	1800
2031	1800
2032	1800

In addition, prior to future Carbon Plan filings additional studies should be performed to inform what levels of annual interconnection are possible.

Q. DO YOU SHARE CLEAN POWER SUPPLY ASSOCIATION'S CONCERNS OVER THE SOLAR INTERCONNECTION CAP?

A. Yes. I agree that the exact MW cap values Duke proposed appear to be somewhat arbitrary and are a significant limitation on the solar resources selected by the model. I also agree with the notion of setting an ambitious goal, which can be adjusted later if found to be unachievable. At the same time, I also appreciate Public Staff's concerns regarding potential execution risks if the limit is set too high (while recognizing that execution risks exist for all of Duke's proposed portfolios). Considering each of these concerns, I initially concluded that it was reasonable to increase the cap from what Duke proposed, particularly in the early years, but not quite to the full level proposed by CPSA.

[12] The dates used in the table above reflect a beginning of year basis, meaning resources are selected at the end of the previous year, for the full calendar year listed.

While I think this approach is still valid, I also recognize that the IRA has some features that may assist in generator interconnection, such as expanding the federal ITC to include qualified interconnection costs for facilities less than 5 MW. Additionally, the potential limitations on interconnection for solar are a primary reason why Strategen recommended exploring procurement of a more diverse set of renewable resources including: (1) additional solar plus storage configurations, including those with higher capacity factors than what Duke modeled in its Initial and Supplemental Portfolios, (2) additional wind options including non-firm "energy only" imports, and (3) increased distributed resources. In addition, Strategen recommended other low-cost methods for alleviating interconnection limits, such as (1) siting facilities at or near retiring coal plants and (2) pursuing grid-enhancing technologies. As such, I recommend that the Commission direct Duke to pursue all five of these strategies, and where possible, include them in any near-term solicitations. Finally, regardless of any MW limits the Commission ultimately considers, perhaps the most important feature of any Carbon Plan will be a concerted effort to accelerate the process for generation interconnection and identify appropriate transmission upgrades.

Q. WHAT WOULD BE A MORE REASONABLE APPROACH FOR CUMULATIVE LIMITS ON SOLAR PLUS STORAGE RESOURCES?

A. Cumulative limits on solar plus storage resources should be removed. As discussed in the Strategen Report, the reliability issue cited by Duke to support the limit does not appear to be based on a real concern.[13] If there are reliability concerns about over-selection of short duration batteries, these should be evaluated through supporting technical analysis.

Q. WHAT WOULD BE A MORE REASONABLE APPROACH FOR SOLAR PLUS STORAGE CONFIGURATIONS?

A. Rather than modeling only two solar plus storage configurations, Duke should have modeled additional configurations, including those with larger sized Direct Current ("DC") components, such as batteries. Duke's Initial Portfolios included only two possible configurations of solar plus storage, which represents a very limited set of choices and does not reflect the range of potential options available. Oversizing the DC components (including the battery) of a solar plus storage system can actually allow solar plus storage resources to operate more similarly to resources that typically have higher capacity factors (like combined cycle units) as well as provide "more bang for the MW buck" of AC interconnection space.[14] While there are limits to the total number of resource types that can reasonably be modeled, the two solar plus storage resource options Duke included are not necessarily representative of the configurations that would maximize value into the future as the Carbon Plan evolves.

Q. DID DUKE'S SUPPLEMENTAL PORTFOLIOS INCLUDE ADDITIONAL SOLAR PLUS STORAGE CONFIGURATIONS?

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[13] *See* Strategen Report, p. 20.
[14] *See* Strategen Report, p. 15-19.

A. The Supplemental Portfolios included one additional configuration, which I support.[15] Notably, this new configuration was preferred by the model. However, Duke should enable even more solar plus storage configurations in subsequent versions of the Carbon Plan, including those with larger DC components.

Q. WHAT WOULD BE A MORE REASONABLE APPROACH FOR SETTING ANNUAL LIMITS FOR ADDITIONS OF ONSHORE WIND?

A. Onshore wind is a mature, low-cost, zero carbon, supply-side generation resource with a recent track record in the U.S. Even though the Carolinas have a relatively modest opportunity for onshore wind resource development, onshore wind should play an important role in the Carbon Plan, whether developed in the Carolinas or imported from neighboring regions. Notably, the 300 MW annual limit is significantly less than that assumed for solar. It is concerning that the wind limit is less than half of that of solar without any further justification from Duke.[16] It is premature to presume both that no more than 300 MW can be procured and that a 2029 in-service date is required prior to testing the market through a true competitive solicitation. While it is true that significant wind resource development has not yet occurred in the Carolinas, such development has occurred already in PJM and there continues to be a substantial amount of wind projects in development there. Thus, the specific limit on onshore wind imports to DEC (*i.e.*, 150 MW of the 300 MW total) is

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[15] Direct Testimony of Snider, et al. for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, NCUC Docket No. E-100, Sub 179 (Aug. 19, 2022) p. 57.
[16] *See* Strategen Report, p. 20-21.

of particular concern. Moreover, it is not clear that Duke even considered imports for DEP. It is worth noting that the transmission costs Duke assumes associated with onshore wind imported from PJM are based upon a Firm Point-to-Point transmission service, which may be overly limiting. Duke should explore the potential for non-firm or "energy only" type of transmission service for these wind imports.[17]

Q. WHAT WOULD BE A MORE REASONABLE APPROACH TO CUMULATIVE LIMITS ON ONSHORE WIND RESOURCES?

A. Similar to the cumulative limits on solar plus storage, cumulative limits on onshore wind resources should be relaxed or removed.

Q. WHAT WOULD BE A MORE REASONABLE APPROACH TO SELECTING A FIRST YEAR FOR SOLAR AND ONSHORE WIND ADDITIONS?

A. Delaying procurement of these resources is not justified. Typical solar and wind project development timelines are often 2-3 years. This is especially true for wind projects imported from PJM that may already be in advanced stages of development. Currently the PJM queue has over 70 onshore wind projects totaling more than 2,400 MW of capacity with targeted in-service dates of 2026 or sooner. Instead of assuming delayed timing is inevitable, the Commission should consider a near-term solicitation to test market readiness with a target in-service date in the 2026-2027 timeframe. This is especially feasible if opportunities for "energy only" wind resource imports are explored.

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[17] *See* Strategen Report, p. 22.

Q. WHAT WOULD BE A MORE REASONABLE APPROACH TO SELECTING NATURAL GAS RESOURCES?

A. I am concerned that Duke's decision to allow the model to select only 1,200 MW Combined Cycle ("CC") units in the base fuel case of its Initial Portfolios unnecessarily limits the model's flexibility and ability to select a smaller sized CC unit. Thus, I support the option for the model to select both F-Class and J-Class CCs and CTs in the Supplemental Portfolios assuming there is sufficient natural gas fuel supply.[18] However, in cases with constrained supply (i.e., No Appalachian Gas), I believe Duke's original approach of limiting CC additions to a single 800 MW F-Class facility makes sense. I am concerned that Duke seems to have abandoned this sensible limitation in its Supplemental Portfolio analysis, which I will address in more detail below (see Section IV-C).

B. Duke's Initial and Supplemental Portfolios were substantially adjusted through non-transparent "out of model" steps. Most of these adjustments can and should have been addressed within the EnCompass model, rather than through a separate analysis.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY "OUT OF MODEL" STEPS.

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[18] Direct Testimony of Snider, et al., p. 58.

A. In developing its proposed Carbon Plan, Duke took several consequential steps to modify the resource portfolios that all occurred outside of the core EnCompass optimization algorithm.

Q. PLEASE EXPLAIN WHY "OUT OF MODEL" STEPS ARE CONCERNING TO YOU.

A. I do not believe all out-of-model adjustments are necessarily unwarranted. However, in my experience, these kinds of additional steps can introduce a new potential "black box" that is non-transparent and can be difficult for stakeholders to independently assess. These types of adjustments run the risk of allowing the utility to "put their thumb on the scale" in favor of certain outcomes. Thus it is generally preferable that these additional steps be minimized.

Additionally, in EnCompass, the simultaneous equations of the optimization algorithm are solved as a set, not in isolation from each other. In practice, this means that if changes to certain variables are made after the optimization is completed, they may no longer represent the optimal solution without additional re-optimization. As a hypothetical example, if the model selected 1,000 MW of battery storage (among other resource selections), which were then manually replaced with 1,000 MW of CTs through an "out of model" adjustment, then it is possible that the other resources previously selected for the portfolio no longer reflect the optimal mix. Since the CTs have different attributes than the battery storage (*i.e.*, longer duration), it is possible that forcing in 1,000 MW of CTs would have led the model to select a smaller quantity of other resources or a different economic retirement schedule. In such cases, the secondary "out of model" step leads to a sub-optimal result unless the portfolio is re-optimized after the 1,000 MW of CTs are forced in.

Q. WHAT "OUT OF MODEL" STEPS DID YOU IDENTIFY IN DUKE'S MODELING?

A. While more details are provided in the Strategen Report, these steps include the following:

- First, Duke delayed the retirement dates beyond the economic dates selected by the EnCompass model for Mayo 1, Marshall 1 & 2, and Belews Creek 1 & 2 (P1 Scenario). Duke explained that this was done to accommodate required transmission upgrades, however I am skeptical of this as explained in Section V below.
- Second, Duke replaced between 1,600 and 2,000 MWs of standalone battery storage selected by the model with between 1,500 and 1,900 MWs of natural gas CTs. Duke explained that this adjustment (referred to as the Battery-CT Optimization) was made because the "typical day" load profile used by the EnCompass included a steeper transition between the daily peak and minimum system load levels. According to Duke, this profile tended to overvalue short duration storage at the expense other resources. The Supplemental Portfolios (SP5 and SP6) included a similar replacement of solar plus storage resources that were initially selected by EnCompass.

- Third, Duke pre-determined the dispatch profile of solar plus storage resources rather than allowing the model to flexibly dispatch the storage component. Under this approach, EnCompass was not allowed to make modifications to the dispatch schedule even if the modeled grid conditions would suggest otherwise.
- Fourth, Duke fixed the level of demand-side resources available by including them in the load forecast.
- Finally, Duke conducted a "Final Reliability Adjustment," which added two additional CTs in a subset of portfolios.

Q. WERE THESE "OUT OF MODEL" STEPS REASONABLE?

A. No, with the possible exception of the Reliability Adjustment. A primary functionality and reason to use a model like EnCompass, is its ability to co-optimize across multiple resource choices and constraints over a set time horizon. Any "out-of-model" adjustments therefore run the risk of distorting the model results and leading to non-optimal results that increase the portfolio's overall costs.

Q. **WHAT WOULD BE A MORE REASONABLE APPROACH TO MODELING THE RETIREMENT OF COAL GENERATING FACILITIES?**

A. Per the Commission's 29 July 2022 order, my suggested approach to coal unit retirements is described below in Section V.

Q. WHAT WOULD BE A MORE REASONABLE APPROACH TO ADDRESSING THE MODEL'S ALLEGED OVERVALUATION OF STANDALONE STORAGE?

A. Instead of including the Battery-CT Optimization step, the "typical day" profile should have been adjusted within EnCompass to more closely reflect real world conditions. As described above, replacing a single variable without additional re-optimization means that the resulting portfolio may no longer represent the optimal solution.

Q. DID DUKE ATTEMPT TO IMPROVE THE "TYPICAL DAY" PROFILE WITHIN ENCOMPASS, AS YOU HAVE SUGGESTED (AND WAS RECOMMENDED IN STRATEGEN'S JULY 2022 REPORT), IN ITS SUPPLEMENTAL PORTFOLIO MODELING?

A. No. In fact, Duke did not even respond to this recommendation in its August 19 testimony. Duke has yet to provide a justification for why it resorted to an out-of-model adjustment rather than seeking to make this improvement within EnCompass and thereby ensuring the integrity of the optimization results.

Q. WHAT WOULD BE A MORE REASONABLE APPROACH TO MODELING SOLAR PLUS STORAGE?

A. Rather than assume a fixed dispatch profile, a more reasonable approach would have been for Duke to have permitted EnCompass to dispatch the storage resources. The fixed dispatch approach significantly devalues additional solar plus storage resources that are added to the system.[19] While there may be

[19] *See* Strategen Report, p. 14-15.

concerns regarding how dispatch decisions affect ITC eligibility, these concerns can still be addressed within the model. Moreover, these concerns are largely irrelevant now due to the IRA which extends ITC eligibility to storage regardless of its generation source and therefore renders previous dispatch limitations as moot. Overall, I support the approach employed in the Supplemental Portfolios, which allowed the model to optimize the battery dispatch profile.

Q. WHAT WOULD BE A MORE REASONABLE APPROACH TO MODEL DEMAND-SIDE RESOURCES?

A. Rather than including demand-side resources as a fixed input into the load forecast, EnCompass should have been allowed to select demand-side resources. In addition, the load forecast should have been adjusted to include a corresponding amount of naturally occurring efficiency to the amount of UEE roll-off. I discuss these issues in more detail in Section X.

Q. DO YOU HAVE ANY RECOMMENDATIONS RELATED TO DUKE'S "FINAL RELIABILITY ADJUSTMENT"?

A. Yes. It is essential that reliability be evaluated comprehensively, to ensure that any simplifications in models like EnCompass do not overlook any potential gaps. Therefore, a step similar to Duke's "final reliability adjustment" may be necessary. However, this modeling step can be difficult to assess. This may allow Duke to "hand select" additional resources when it is often unclear what underlying reliability issues need to be addressed or whether the selected resources are a good fit.

For this Carbon Plan cycle, I do not recommend removing this reliability adjustment step because the adjustments made by Duke appear to be relatively limited and well into the next decade (at least in the case of the Initial Portfolios). As such, I am not too concerned by these changes in this proceeding. However, in future iterations of the Carbon Plan, it will be important to make sure that transparent information is provided about these types of reliability adjustments, including (1) the size and type of adjustment made, (2) the reason for the change, including any 8760 hourly model data that showed reliability deficiencies, and (3) alternatives that were considered. This will allow the Commission and stakeholders to ensure that additions are truly needed to address reliability gaps.

Q. WHAT IMPACT WOULD REMOVING THESE "OUT OF MODEL" STEPS HAVE ON THE OUTCOME OF THE MODELING?

A. Conducting the portfolio analysis without these additional steps (with the exception of the reliability adjustment) would lead to a more internally consistent and more optimal result. This would include greater assurance that the least cost choices are being made in terms of retirement dates and resource additions.

Q. CAN YOU SUMMARIZE YOUR RECOMMENDATIONS FOR THE ABOVE MODELING PROBLEMS (I.E., UNREASONABLE RESOURCE CONSTRAINTS, AND "OUT OF MODEL" ADJUSTMENTS)?

A. I recommend that the Commission reject Carbon Plan portfolios that do not eliminate or significantly relax the constraints identified above. Portfolio model runs with these relaxed constraints should also be included in the supporting analysis provided as part of any application made by Duke for a certificate of public convenience and necessity ("CPCN applications") for near-term resources selected in the Carbon Plan.

In future iterations of its Carbon Plan, the Commission should also require Duke to minimize the number of out-of-model adjustments made. Finally, the Commission should also require Duke to provide full transparency on what specific resource additions were made through reliability adjustments, or other out-of-model changes, and the reasons for those changes.

C. Some of Duke's assumptions for new gas resource are questionable and warrant further scrutiny

Q. DO YOU HAVE ANY CONCERNS REGARDING THE MODELING ASSUMPTIONS RELATED TO NATURAL GAS GENERATION?

A. Yes. I have concerns about both the natural gas price and natural gas supply assumptions used by Duke, the effective load carrying capacity ("ELCC") values used by Duke, and Duke's assumptions about switching natural gas generators to operate on hydrogen.

i. Current natural gas prices are significantly higher than the "worst case scenario" that Duke modeled in its Carbon Plan.

Q. WHAT CONCERNS DO YOU HAVE ABOUT THE NATURAL GAS PRICE ASSUMPTIONS USED BY DUKE IN ITS MODELING?

A. Duke's plan was developed before the recent and significant increase in natural gas prices driven in part by Russia's invasion of Ukraine. This means that current gas prices are significantly higher than the "worst case scenario" that Duke assumed in its Carbon Plan.[20]

Q. DO YOU SHARE ANY OF PUBLIC STAFF'S CONCERNS REGARDING NATURAL GAS COMMODITY PRICING AND DELIVERABILITY?

A. Yes. However, I have some additional concerns that I do not think Public Staff has fully addressed. For example, Public Staff is somewhat dismissive of the recent surge in natural gas prices, stating that "the natural gas forecasts contained in the Proposed Carbon Plan affect capacity expansion starting around year 2026, well beyond the current price volatility."[21] This implies that current prices will eventually subside and return to where they have been in the recent past. However, it is not clear when or if that will be the case. For example, due to the development of LNG export terminals in recent years, the U.S. gas market is now much more exposed to global commodity prices than it was in

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[20] *See* Strategen Report, p. 23-24.
[21] Public Staff Comments, p. 71.

the previous decade.[22] These global prices are in turn more affected by unpredictable dynamics such as the war in Ukraine. Public Staff has not provided evidence to suggest when/if a "return to normalcy" will occur. Even Duke conceded that the long-term market price for natural gas, delivered in 2027, has increased by $0.71/MMBtu or nearly 20% relative to the Company's original assumptions.[23] As a result, I believe it is essential to err on the side of caution when considering future natural gas prices. In practice this means the Commission should seriously examine the high gas price sensitivity. It also suggests that the Commission should seek to limit customers' exposure to natural gas prices by minimizing or delaying addition of new gas plants where possible.

Q. WHAT ARE YOUR RECOMMENDATIONS RELATED TO THE NATURAL GAS PRICE ASSUMPTIONS USED BY DUKE IN ITS MODELING?

A. Although Duke may not have been able to foresee the recent run-up in gas prices and adjust its plan accordingly, it is instructive to consider the implications of this recent development by examining the "High Gas Price Forecast" sensitivity cases that Duke provided. However, because Duke did not re-optimize resource selections for this sensitivity case, the results are of limited value in considering potential changes to the underlying resource portfolio. If Duke had re-optimized the portfolio under higher gas prices, then it is probable

[22] The United States became the world's largest LNG exporter in the first half of 2022, U.S. Energy Information Administration (July 25, 2022), https://www.eia.gov/todayinenergy/detail.php?id=53159.
[23] Snider, et al., page 176

that fewer gas units (and CC units in particular) would have been selected. Since fuel costs are directly passed to Duke's customers through the annual fuel clause proceeding, this price risk is borne primarily by Duke's customers rather than by Duke itself. Given the potential magnitude of this price risk, I recommend that the Commission consider all options available to reduce exposure to gas fuel prices, including alternatives that could reduce new CC buildouts. Finally, the presumption that new CTs will operate on ULSD at least some of the time will add to their operating cost and emissions contribution. These impacts should be reflected in future modeling.

ii. There are significant uncertainties regarding the feasibility and cost of securing firm transportation of natural gas sufficient to fuel new CC plants. It is not clear that these costs were correctly modeled by Duke in its resource selection process.

Q. WHAT CONCERNS DO YOU HAVE ABOUT THE NATURAL GAS SUPPLY ASSUMPTIONS USED BY DUKE IN ITS MODELING?

A. Duke's base fuel supply assumption in both its Initial Portfolios (P1-P4) and Supplemental Portfolios (SP5 and SP6) is that the Companies will be able to obtain incremental firm transportation ("FT") service to supply Duke's existing CC fleet as well as a limited number of new CC units. For P1-P4, Duke assumed that it could secure incremental FT service to access Appalachian gas (e.g., via the Mountain Valley Pipeline), whereas SP5 and SP6 assumed incremental access to Transco Zone 4.[24] In both cases, new gas pipeline capacity would be required. Absent new gas pipeline capacity, Duke's CC fleet does not have access to a firm fuel supply. This deficiency in firm fuel does not only apply to new CC units being considered, but it also applies to Duke's existing fleet. In light of this lack of firm fuel, I am concerned that Duke may be overstating the reliability contribution of its CC units (both new and existing). If the CCs cannot obtain firm fuel supplies, then they are subject to disruptions during peak load hours. The lack of firm natural gas delivery was one factor that led to the near collapse of the power grid in Texas during the winter storm of February 2021.[25] Given the limited available pipeline capacity in the region to support firm delivery of gas to both existing and new CC units, reliance on natural gas introduces a significant reliability risk in the event of severe cold weather when gas demand is high throughout the region and CC units have to compete with retail natural gas customers for fuel supply. Expanding Duke's gas CC fleet will only exacerbate this risk, potentially negating any effort to mitigate the current risk to Duke's existing fleet.

Moreover, the incremental FT service Duke assumes in its base case is significant. According to the Company, the incremental FT service assumed in

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[24] See Duke Carbon Plan, Appendix E, p. 42, which states: "This incremental firm supply allows for the Companies' existing CC fleet to be fully supported by interstate firm transportation and with the potential for capacity for a limited amount of new CC units to also operate at this gas price."; Direct Testimony of Snider, et. al, Exh. 1, p. 3, which states: "Existing CC fleet fueled Transco Zone 4, FT for two new CCs with Transco Zone 4"

[25] *See* Strategen Report, p 26.

the base case suggests that the Company [BEGIN CONFIDENTIAL] [redacted].[26] [END CONFIDENTIAL]

Q. WERE THE COSTS OF SECURING INCREMENTAL FT SERVICE CORRECTLY INCLUDED AS PART OF THE COST OF NEW CC RESOURCES WHEN DUKE PERFORMED ITS ENCOMPASS MODELING?

A. I don't believe so. It is not obvious that the costs of this additional pipeline capacity are fully accounted for in Duke's EnCompass analysis for resource selection.[27] Strategen is concerned that Duke's analysis may have underestimated the fixed costs necessary to secure firm fuel transportation for new CC resources.

Q. DID DUKE MODEL ANY PORTFOLIOS WITH MORE CONSERVATIVE INCREMENTAL FT ASSUMPTIONS?

A. Yes. To account for the likelihood that Duke is unable to secure access to Appalachian gas, Duke's Initial Portfolios also included an "Alternate Fuel Supply Sensitivity," under which new CC units will have to rely on delivered gas from the higher-cost Transco Zone 5 and dual-fuel capability. Additionally, the remaining portion of Duke's existing CC fleet will also not have firm interstate capacity. The limited firm transportation under the Alternate Fuel Supply Sensitivity results in fewer CC units in all four portfolios (i.e., $P1_A$-$P4_A$),

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[26] *See* Strategen Report, p. 25 and Duke Energy Confidential Response to AGO DR 8-9 (attached as Exhibit 3).
[27] *See* Strategen Report, p. 25-26.

reducing the amount of new CC from 2,400 MW to 800 MW. In contrast, none of the Supplemental Portfolios (SP5, SP6, $SP5_A$, and $SP6_A$) included these more conservative assumptions for FT service, and each assumed gas supply would be sufficient to support both the existing CC deficiency and 2,400 MW of new CC capacity.

Q. DO YOU HAVE CONCERNS WITH PUBLIC STAFF'S APPROACH TO NATURAL GAS DELIVERABILITY?

A. Yes. First, as discussed above and addressed in the Strategen report,[28] there appears to be some discrepancies in Duke's cost assumptions for firm transport of gas to new CC units and what was included in the EnCompass model. It does not appear that Public Staff has addressed this issue, despite an otherwise thorough discussion in their July 15th comments. Second, I am very concerned about Public Staff's apparent recommendation to Duke that the No Appalachian gas portfolios in the Supplemental Portfolio analysis (i.e., SP5 and SP6) would be able to support "up to 2,400 CC, supported with Transco Zone 4 interstate FT for this capacity."[29] Public Staff's comments provided no evidence that securing incremental FT supply of this magnitude from Transco Zone 4 would be feasible or cost effective. Bear in mind, Public Staff's recommendation (and Duke's subsequent modeling) for SP5 and SP6 suggested that incremental FT from Zone 4 would be available to support not only 2,400 MW of new CC capacity, but also Duke's current deficiency. [BEGIN CONFIDENTIAL] [redacted]

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[28] Strategen Report, page 26.
[29] Duke Energy Response to AGO DR 8-10.

[redacted][30] [END CONFIDENTIAL] Public Staff's Comments mention "recent proposals for Williams Transco upgrade projects" which I interpret to mean the proposed Southside Reliability Project. However, [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Moreover, as discussed in the Strategen Report, none of this additional FT capacity for this project is currently earmarked for electricity.[31] Given these concerns, I don't believe Public Staff's recommended FT assumptions, which underpin Duke's analysis for SP5 and SP6, are reasonable.

Q. WHAT RECOMMENDATIONS DO YOU HAVE REGARDING THE NATURAL GAS SUPPLY ASSUMPTIONS USED BY DUKE IN ITS MODELING?

A. Given the potential risk of gas deliverability to the proposed new CC projects, and the reliability risks this may impose, I strongly recommend that the Commission consider Duke's Alternate Fuel Supply Sensitivity (i.e., "No Appalachian Gas") as modeled in $P1_A$-$P4_A$ as a better primary assumption for the Carbon Plan instead of the Base Fuel Supply case of the Initial Portfolios (i.e., P1-P4) or the Supplemental Portfolios (i.e., SP5, SP6, $SP5_A$, and $SP6_A$).

[30] Exhibit 3.
[31] Strategen Report, p 27.

iii. Clean hydrogen fuel is an emerging technology, and it is premature to include it in the Carbon Plan at this time.

Q. WHAT CONCERNS DO YOU HAVE ABOUT DUKE'S ASSUMPTIONS REGARDING THE CONVERSION OF ITS NATURAL GAS GENERATION TO OPERATE ON HYDROGEN?

A. Duke modeled natural gas plants with a 35-year lifetime. Therefore, any new CC or CT would operate past the 2050 deadline under HB951 for achieving net zero carbon emissions. Duke attempts to address this concern by assuming that any new gas plant built in the 2040s will operate on 100% hydrogen and those added before 2040 will be converted to 100% hydrogen by 2050. There are two key problems with this approach: (1) many of the cost assumptions used to model these resources are speculative,[32] and (2) the feasibility of this plan is questionable.

Additionally, the assumed conversion to hydrogen fuel in the 2050 timeframe may underestimate the portfolio costs of any new gas resource from a present value of revenue requirement ("PVRR") perspective. This is because all PVRR calculations performed by Duke are done only through 2050,[33] including any necessary fixed cost investments.[34] This means that the potentially significant future cost of hydrogen conversion of gas resources is largely absent from Duke's Carbon Plan simply due to the time horizon selected for the analysis.

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[32] *See* Strategen Report, p. 29.
[33] Duke Energy Response to AGO DR 4-3.
[34] Duke Energy Response to AGO DR 4-4.

Regarding hydrogen supply, Duke calculated that curtailed or unutilized carbon-free energy could be used to produce enough hydrogen to meet all hydrogen needs on Duke's system through 2049 and nearly half of hydrogen needs in 2050.[35] However, these calculations did not address the costs to produce the hydrogen through electrolysis or the availability of the remaining hydrogen need in 2050 and beyond. Duke also did not attempt to account for the increased carbon-free generation capacity necessary to produce this hydrogen in the Carbon Plan.[36]

There are also key concerns about the feasibility of Duke's plan to operate all natural gas generation on 100% hydrogen by 2050. The ability of gas units to operate on hydrogen by 2050 depends on overcoming many uncertainties and challenges related to the cost-effective production, transportation, storage, and combustion of green hydrogen fuel and related equipment.[37] Despite such uncertainties, Duke relies heavily on the assumption that a robust hydrogen market will develop by 2050 to justify a significant buildout of natural gas units in the near term. While hydrogen combustion may ultimately become feasible in the 2030s, planning based on today's technologies suggests that new natural gas plants would likely need to retire early and impose significant additional stranded costs on Duke's customers.

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[35] Duke Carbon Plan, Appendix E, p. 102.
[36] Duke Energy Response to AGO DR 4-13.
[37] *See* Strategen Report, p. 29-30.

Q. WHAT WOULD BE A MORE REASONABLE WAY TO MODEL THE POTENTIAL THAT NATURAL GAS GENERATION BE RUN ON 100% HYDROGEN BY 2050?

A. Given the significant uncertainty around the potential costs of hydrogen conversion, as well as around whether a robust hydrogen market will materialize, it appears to be premature to assume that new gas plants added in the near term will convert to hydrogen. The approach taken in the Supplemental Portfolios addresses these concerns by removing hydrogen fuel. Additionally, it may also be prudent to assume that all new natural gas plants have lifetimes that do not exceed the 2050 timeframe, due to the zero emission target. Practically speaking, this means that the CC and CT additions contemplated as part of the near-term action plan (*i.e.*, with in-service dates in the 2029 timeframe) should be modeled assuming 20-year lifetimes, rather than the 35-year lifetimes that Duke has assumed, at least until there is more clarity on the future of the hydrogen market. It may also make sense to delay a decision on new CC and CT additions as long as possible in order to monitor the development of green hydrogen technologies, gain further clarity on costs, and avoid stranded asset risks for consumers.

Q. PUBLIC STAFF RAISES CONCERNS ABOUT DUKE'S ASSUMPTIONS REGARDING HYDROGEN BLENDING. DO YOU SHARE THESE CONCERNS?

A. Yes. In fact, when energy density of the fuel is considered, the carbon reduction benefit of hydrogen blending is actually fairly small relative to the volume of natural gas fuel replaced.

D. Public Staff's comparison of portfolio CO2 abatement costs is incomplete and outdated given the impact of the IRA.

Q. DO YOU AGREE WITH THE METHODOLOGY USED IN PUBLIC STAFF'S ANALYSIS COMPARING CO_2 ABATEMENT COSTS OF THE FOUR PORTFOLIOS PROPOSED BY DUKE AND THEIR RESULTING CONCLUSION THAT THE P1 PORTFOLIO IS NOT JUSTIFIED EVEN WHEN CONSIDERING THE SOCIAL COST OF CARBON ("SCC")?

A. No. While I appreciate the analysis that Public Staff has conducted, it does not appear definitive to me that P1 should be eliminated based on CO_2 abatement costs. More specifically, Public Staff relies upon the 2021 Interagency Working Group on Social Cost of Greenhouse Gases[38] which includes multiple potential scenarios for the SCC values. Public Staff apparently selected the 3% discount rate scenario for its analysis; however, it is not clear why this scenario was selected over others. For example, the same report also includes SCC values ranging from \$22/ton to \$206/ton in 2035 depending on the scenario selected. Under the 3% (95th percentile) scenario, Portfolio 1 would be the most cost effective. Under the 2.5% discount rate scenario, P1 would perform better than

[38] Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide, Interagency Working Group (Feb. 2021), https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

P2, and roughly equal to P4 in 2035. Furthermore, Public Staff appears to have inappropriately applied the 2035 SCC values for its 2050 evaluation. Finally, the IRA likely changes the cost-benefit analysis that Public Staff performed – especially the cost of solar and storage which are higher in P1. Thus, the analysis should be revisited, and I would expect that P1 would perform much more favorably.

E. Duke's Supplemental Portfolios (SP5 and SP6) do not fully address the AGO's concerns. The Commission should not adopt a Carbon Plan that does not resolve these issues.

Q. DID DUKE'S SUPPLEMENTAL PORTFOLIOS ADDRESS ALL OF THE CONCERNS THAT THE AGO/STRATEGEN HAD PREVIOUSLY RAISED IN ITS JULY 2022 REPORT?

A. No. While it did address some of these concerns, it did not address all of them. The Table below provides a summary of which concerns were addressed and which were not. This table is comparable to Table SPA-1 in Duke's testimony.

Table 3

Modeling Issue Identified by AGO/Strategen	Approach Used in Initial Portfolios P1-P4	Approach Used in Supplemental Portfolios SP5-SP6	Do SP5 & SP6 Address AGO's Concerns?
SPS Battery Dispatch Optimization	Fixed battery dispatch profile	Model optimized battery dispatch	Yes
Available SPS Battery Configurations	• 4-hr, 25% battery to solar ratio • 2-hr, 50% battery to solar ratio	• 4-hr, 25% battery to solar ratio • 2-hr, 50% battery to solar ratio • 4-hr, 50% battery to solar ratio	Partially (additional configurations would have been helpful)
Cumulative Battery Limits	4-hr battery capped at 1,500 MW in DEC and 1,800 MW in DEP;	4-hr and 6-hr battery not capped, but continue to decline in capacity value at higher penetrations	Yes

	6- hr battery at 3,200 MW in DEC and 2,000 MW in DEP		
Cumulative SPS Limits	50% battery to solar ratio capped at 450 MW in DEC and 750 MW in DEP	Limit remains for original solar plus storage configuration	No
Inclusion of Hydrogen Fuel	H2 Fuel Included	H2 Fuel <u>Not</u> Included	Yes
Availability of incremental FT Under “No Appalachian Fuel” Supply Case	No incremental FT for new CCs	FT for existing CCs plus two new CCs with Transco Zone 4	No; unclear if 400,000 dkt/day of FT is available at Transco Zone 4; insufficient for both existing and new CCs.
Cost of incremental FT	EnCompass inputs were too low	EnCompass inputs more reasonable, but may still be too low	Possibly
Availability of F-Class and J-Class CCs and CTs	Smaller F-Class CC available in no Appalachian fuel supply case. Larger J-Class CC available in limited Appalachian supply case. Only J-Class CTs available.	Both J-Class and F-Class CCs and CTs available in both fuel supply scenarios.	Partially; Strategen recommended that both sizes be available in the Base case, but not in the “No Appalachian Gas” case due to gas availability.
Useful Life of New Gas	35 years	35 years	No; Strategen recommended 20 years
Coal Retirements Dates	Predetermined outside of core model (i.e., Not Economically Selected in Core Model)	Predetermined, (i.e., Not Economically Selected in Core Model)	No; Strategen recommended economically selected dates
Belews Creek conversion to 100% NG	Not modeled	Not modeled	No; allow prior to 2030
Battery/CT Replacement	Conducted as an “out of model” step	Conducted as an “out of model” step	No. In-model adjustments should have been made.
Solar Limits	See Table SPA-1	Same as P2-4; (high solar sensitivity modeled)	No; recommended increase in early years to >1000 MW
Wind Limits	See Table E-41	Unchanged	No; recommended increase annual limit & first year deployment; allow non-firm transmission

Load Forecast	UEE Base Case	UEE Base Case (low UEE modeled)	No; recommend high UEE, and/or load forecast adjustment
Compliance Date	P1: 2030 P2: 2032 P3: 2034 P4: 2034	P5: 2032 P6: 2034	No; AGO/Strategen recommended 2030

Q. DID THE RESULTS OF DUKE'S SUPPLEMENTAL PORTFOLIO MODELING VALIDATE ANY OF THE ORIGINAL CONCERNS RAISED BY AGO/STRATEGEN?

A. Yes. As Duke explained in its testimony, the inclusion of an additional solar plus storage ("SPS") configuration with a larger battery, along with revised SPS modeling (both of which the AGO/Strategen recommended) led to more SPS being selected. Moreover, the results suggest that there may be merit to exploring additional SPS configurations going forward. This also demonstrates more broadly that AGO/Strategen's concerns are legitimately focused on issues that could have a material impact on the Carbon Plan and should not be casually dismissed. Yet, Duke did dismiss several of these concerns.

Q. WERE YOU CONSULTED BY DUKE OR THE PUBLIC STAFF IN THE DEVELOPMENT OF DUKE'S SUPPLEMENTAL PORTFOLIO MODELING?

A. No.

Q. SEVERAL OF AGO/STRATEGEN'S CONCERNS WERE NOT ADDRESSED IN DUKE'S SUPPLEMENTAL PORTFOLIO MODELING. DID THE AGO SEEK TO HAVE THESE CONCERNS

ADDRESSED BY DUKE IN ITS SUPPLEMENTAL PORTFOLIO MODELING EFFORTS?

A. Yes. However, Duke did not agree to several of the additional changes that the AGO requested. Moreover, Duke did not provide satisfactory reasons for why several of the requested changes should not be included.

Q. BEYOND THOSE INITIAL CONCERNS, DID DUKE'S SUPPLEMENTAL PORTFOLIO MODELING INTRODUCE NEW ASSUMPTIONS THAT YOU ARE CONCERNED ABOUT?

A. Yes. Most notably, I am concerned about the new assumptions relating to natural gas fuel supply under the "No Appalachian Gas" case. Specifically, SP5 and SP6 assumed that Duke would be able to secure 400,000 dekatherms/day of incremental firm transport from Transco Zone 4. Duke explains that this would be sufficient for "enough firm supply for two large, or three small, CC units" or about 2,400 MW of new CC units in total. This contrasts with Duke's previous approach in its Initial Portfolios which limited new CC additions to 800 MW under the "No Appalachian Gas" scenario. Duke's testimony did not address the feasibility or cost of securing 400,000 dekatherms/day of incremental firm transport. This is a critical input underpinning the viability of Duke's proposed CC additions in the Supplemental Portfolios and needs significant scrutiny.

Q. HAS THE AGO/STRATEGEN PERFORMED ANY FURTHER MODELING TO ADDRESS THESE OUTSTANDING CONCERNS?

A. Yes. This is described in Section IV-F below.

F. AGO Supplemental Portfolio Modeling

Q. DID DUKE'S SUPPLEMENTAL PORTFOLIOS ADDRESS ALL OF THE CONCERNS THAT AGO RAISED IN ITS JULY COMMENTS?

A. No. As summarized in Table 3 above, Duke's Supplemental Portfolios did address some concerns shared between AGO and Public Staff but left many of AGO's concerns unaddressed.

Q. DID THE AGO MAKE A REQUEST TO DUKE THAT THESE ISSUES BE ADDRESSED IN ITS SUPPLEMENTAL PORTFOLIO ANALYSIS?

A. Yes. However, after some initial discussions with Duke, the Company indicated that it was not able to complete the AGO's request within the timeframe allotted. This in turn led the AGO to file its motion to require Duke to conduct the additional modeling.

Q. GIVEN DUKE'S REFUSAL TO COMPLETE THE AGO'S REQUESTS, HAS THE AGO SOUGHT OTHER MEANS TO CONDUCT THIS ANALYSIS?

A. Yes. While not part of its initial scope of work, the AGO has engaged Strategen to conduct supplemental portfolio analysis in EnCompass. This scenario analysis builds upon SP5 but includes several key modifications. A more complete description of this analysis and its findings is attached to my testimony as Exhibit 2.

Q. WHAT ARE SOME OF THE KEY MODIFICATIONS INCLUDED IN THE AGO'S SUPPLEMENTAL PORTFOLIO ANALYSIS?

A. As explained above, there were several modeling issues identified by AGO/Strategen in the July comments/report which were described in Table 3 above. Table 4 below explains how these same issues were addressed in the SP-AGO scenario.

Table 4

Modeling Issue Identified by AGO/Strategen	**Do SP5 & SP6 Address AGO's Concerns?**	**Approach Used in SP-AGO**
SPS Battery Dispatch Optimization	Yes	Same as SP5
Available SPS Battery Configurations	Partially (additional configurations would have been helpful)	Same as SP5
Cumulative Battery Limits	Yes	Same as SP5
Cumulative SPS Limits	No	Cumulative limits removed
Availability of incremental FT Under "No Appalachian Fuel" Supply Case	No; unclear if 400,000 dkt/day of FT is available at Transco Zone 4; insufficient for both existing and new CCs.	Gas expansion assumptions consistent with $P1_A$ -$P4_A$
Cost of incremental FT	Possibly	Same as SP5
Availability of F-Class and J-Class CCs and CTs	Partially; Strategen recommended that both sizes be available in the Base case, but not in the "No Appalachian Gas" case due to gas availability.	Gas expansion assumptions consistent with $P1_A$ -$P4_A$
Useful Life of New Gas	No; Strategen recommended 20 years	20-year life
Coal Retirements Dates	No; Strategen recommended economically selected dates	Economically selected

Belews Creek conversion to 100% NG	No; allow prior to 2030	Conversion by 2028
Battery/CT Replacement	No. In-model adjustments should have been made.	Same as SP5 (no in-model adjustments made due to time constraints)
Solar Limits	No; recommended increase early years to >1000 MW	Midpoint of High Solar Case and P1 (see Table 2 above);
Wind Limits	No; recommended increase annual limit & first year deployment; allow non-firm transmission	Increased annual import limit allowing for non-firm transmission (0% ELCC); First addition in 2027
Load Forecast	No; recommend high UEE, and/or load forecast adjustment	Same as SP5 (no adjustments made due to time constraints)
HB 951 Compliance Date	No; AGO/Strategen recommended 2030	2030 compliance date

Q. WHAT ARE SOME OF THE KEY FINDINGS FROM THIS ANALYSIS?

A. The results of the EnCompass analysis using the SP-AGO inputs listed above show that a feasible portfolio is achievable with a 2030 compliance date at a substantially lower cost than the P1 and $P1_A$ portfolios. Some of the key features of the SP-AGO portfolio include the following:

- Meets 2030 compliance with HB 951, and achieves lower cumulative emissions than any Duke-modeled portfolio.
- Significant investments in solar plus storage, including over 3,100 MW added in the 2027-2028 timeframe. As much as 1,200 MW of the newly added configuration (50% battery ratio with 4-hr storage) is selected in the following two years.

- Over 500 MW of battery storage added in 2027, increasing to 2,000 MW in 2028. This roughly coincides with retirements at the Mayo 1 and Marshall 1 and 2 plants.
- Despite having zero assumed capacity contribution, significant additions of onshore wind imports with non-firm transmission were selected. These additions were selected as soon as the model would allow (i.e., 2027).
- New gas CT units were selected at the end of 2028 for DEP (462 MW). No new gas CC units were added.
- Economic retirement of the Mayo coal plant occurs in 2027 and Marshall 1 and 2 in 2028. Belews Creek is converted to gas prior to 2030.
- Present Value Revenue Requirement (PVRR) through 2050 (DEP/DEC Combined System) of $100 billion is lower in cost than other 2030-compliant portfolios (e.g., P1 and $P1_A$) and also lower than SP5.

Q. WERE THERE ANY LIMITATIONS IN THE ANALYSIS SUPPORTING AGO'S SUPPLEMENTAL PORTFOLIO?

A. Yes. An analysis like this normally would be conducted over several months. However, due to the circumstances (including Duke's refusal to consider AGO's inputs) it had to be conducted in under 2 weeks. Given more time a more complete analysis could have been pursued, however, this was not possible due to time constraints. Nonetheless, I believe the model results are robust enough for the Commission's consideration. In full transparency there are certain limitations that should be acknowledged and which I believe can be improved upon given ample time to do so.

First, due to the complexities of modeling the Belews Creek gas conversion, this resource was simply included in the 2028 timeframe rather than being a result of the model's resource selection process. While this is less than ideal, I am confident that this is a reasonable approximation of the optimal outcome due to the considerably favorable economics of this conversion over a new gas plant addition.

Second, although Strategen identified serious concerns with Duke's underlying load forecast (including the long-term effects of UEE), there was insufficient time to develop an alternative load forecast and as such Duke's forecast was used. Ideally, this would have been adjusted to better reflect naturally occurring EE, which would have led to a reduced overall resource need.

Third, there was insufficient time to model additional solar plus storage configurations, including those with higher capacity factors. I believe this could be a highly consequential change and should be considered in future modeling efforts.

Finally, AGO/Strategen's intention was to exclude H2 from the SP-AGO model run, consistent with SP5. However, an inadvertent modeling error allowed H2 resources to be selected in the 2040-2050 timeframe. This error was discovered less than 24 hours before the deadline for this testimony and caused some H2 resources to be included in that timeframe. Given the substantial time for new model runs to be completed and interpreted (typically more than 24 hours), there was insufficient opportunity to correct this. Strategen is currently working to do so. I expect that the effect of this change will be relatively small, and do not anticipate it to impact any near-term actions. Any impact would be in the 2040-2050 timeframe.

V. COAL UNIT RETIREMENT SCHEDULE

A. Duke's modeled portfolios include adjusted coal retirement dates that were inconsistent with the economically optimal results.

Q. HOW DID DUKE ADDRESS COAL UNIT RETIREMENTS?

A. In its proposed Carbon Plan, Duke claims to have initially run its model using the most economic retirement dates of its coal plants ("endogenous retirements"). However, Duke then made subjective changes to these dates without further explanation of each change being made in its filing. Duke claimed that these "minor adjustments"[39] were made by applying "limited professional engineering judgments,"[40] but did not elaborate. This is concerning because it may mean that Duke is not aligning its coal retirement schedule with

[39] Duke Carbon Plan, Appendix E, p. 49.
[40] Duke Carbon Plan, Appendix E, p. 45.

the dates that are most optimal for reducing customer costs under HB951's requirements.

Q. DID DUKE GIVE A REASON FOR ADJUSTING THE ENDOGENOUS RETIREMENT DATES?

A. Not in its initial Carbon Plan filing. In response to a data request, Duke provided high level explanations for some of the changes that were made.[41]

Q. WHAT WAS THE IMPACT OF THESE CHANGES?

A. Despite referring to these changes as "minor adjustments,"[42] a substantial number of the retirement dates were altered. Some of these changes were quite significant. For the P1 portfolio, the economic retirement dates for Belews Creek 1 & 2, Marshall 1 & 2, and Mayo 1 occur much sooner than what Duke has proposed. These changes are noteworthy since they overlap substantially with the timing of in-service dates for resources procured as part of Duke's proposed near-term action plan. Thus, they could have a significant effect on resource decisions made in the 2026- 2030 timeframe.

For Mayo 1, Duke revealed that the economic date was 2026 in all scenarios, rather than the 2029 date it ultimately selected.[43] Duke selected the 2029 date even though the Company confirmed that the earliest retirement date could be as soon as 2027 and that battery technology could be a replacement option.[44]

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[41] Duke Energy Second Supplemental Response to AGO DR 4-7 (attached as Exhibit 4).
[42] Duke Carbon Plan, Appendix E, p. 49.
[43] Exhibit 4.
[44] Id.

Meanwhile, Duke's assumption for the earliest possible deployment of battery storage is 2025, which is much sooner than the 2027 earliest retirement date.

Similarly, Duke delayed the retirement date for Marshall 1 and 2 from the economic date of 2026 to a later date of 2029. Duke explained that the economic 2026 retirement date was not selected due to transmission needs at the site. Specifically in Appendix P of the Carbon Plan, Duke states the following: "If any Marshall coal units are retired and not replaced with new generation on-site, then significant transmission projects will be needed." However, this suggests that on-site resources (like the battery storage mentioned above, or CTs), could potentially avoid these transmission upgrades and allow for the more economical 2026 retirement date to be pursued.

For Belews Creek 1 & 2, the economic retirement date was as early as 2030, yet the Company selected 2036 as the retirement date. Duke explained that the adjustment was made "based on a number of considerations including the units' flexibility to co-fire natural gas, the sheer size of the replacement generation, reliability benefits, providing additional time for development of SMR technology and supporting the corporate goal to be out of coal generation by the end of 2035."[45] This explanation is not sufficiently precise to support delaying the retirement dates to such a degree. The response also suggests that

[45] Exhibit 4.

Duke may be targeting the Belews Creek site for a potential SMR deployment in the mid-2030s rather than considering more economic alternatives.

B. Earlier retirement of coal generation at the Marshall, Mayo, and Belews Creek plants may be both economic and feasible. Duke's rationale for delaying these is insufficient.

Q. WHAT ALTERNATIVE APPROACH TO COAL RETIREMENTS WOULD YOU RECOMMEND?

A. Contrary to Duke's proposal, the least cost solution may be to accelerate procurement of about 1,473 MW of new resources to the 2025-2026 timeframe to replace uneconomic coal operations at Marshall 1 and 2, and at Mayo 1. By keeping these plants online longer than is optimal, they are effectively "crowding out" other more economic resources that could be considered earlier in the action plan. Meanwhile, given the relatively short timeframe, it may make sense to target replacement resources that can be deployed quickly at these facilities such as battery storage (or possibly solar plus storage, space permitting).

In Appendix P, Duke cited transmission upgrades as being necessary for retirement of certain coal plants, including Belews Creek. There should be ample opportunity to complete any necessary transmission upgrades prior to 2030, rather than waiting until 2036. During the 2020 IRP process, Strategen raised significant concerns about Duke's assessment of the need for these retirement-related transmission upgrades.[46]

Q. WHAT RECOMMENDATIONS WOULD YOU MAKE REGARDING COAL UNIT RETIREMENTS?

A. EnCompass' economic retirement dates should be considered feasible if: (1) onsite generation is installed earlier (*e.g.*, battery storage before 2026 at Mayo or Marshall), or (2) transmission upgrades are installed earlier (*e.g.*, by 2030 for Belews Creek). The Commission should also explore whether it would be feasible to modify Belews Creek to operate on 100% natural gas as an alternative to retirement and direct Duke to include this gas conversion as an option in all future scenarios.

Q. DO YOU HAVE ANY ADDITIONAL CONCERNS REGARDING DUKE'S PROPOSED COAL RETIREMENT DATES?

A. Yes. One additional area of concern is the relationship between coal retirement dates and the high gas price forecast discussed above.

I am concerned that all of the high gas price sensitivity runs result in portfolios that do not comply with the HB951 emission reduction requirements. At a basic level, this is simply due to the fact that, under high gas price conditions, Duke dispatches its coal fleet more frequently, which leads to greater emissions. As discussed in Section IV, there is a distinct possibility that we will be headed

[46] These concerns included duplicative projects, shifting explanations of the deficiencies to be addressed, inaccurate planning assumptions, and inconsistencies with recent operations, among others. These concerns were presented at the October 2021 Technical Workshop.

towards a scenario closer to the high gas price sensitivity. However, it is not clear that Duke has developed a portfolio under these conditions that would actually meet the requirements of HB951 due to the coal redispatch issues described above. For example, Tables E-96 and E-97 in Appendix E of Duke's Carbon Plan show carbon reductions fail to reach the 70% statutory target. This is also indicative of the fact that Duke did not re-optimize the coal retirement schedule under the high gas price sensitivity cases as a means to identify a workable solution.

Q. HOW WOULD YOU ADDRESS THIS CONCERN?

A. As discussed above in Section IV, it is especially important to give weight to the high gas price sensitivity cases, including both the Base Portfolios (*e.g.*, P1-P4) and Alternative Fuel Supply Portfolios (*e.g.*, $P1_A$-$P4_A$). In addition, Duke should develop a contingency plan in case gas prices remain high.

One potential solution to meeting the 70% statutory target under this environment would be to accelerate certain coal retirements such that they occur before the statutory deadline (*e.g.*, 2030) while allowing other cleaner resources to take their place. This is especially relevant for the Belews Creek plant, which showed an economic retirement date as soon as 2030 in some cases. Removing Belews Creek from Duke's system by 2030 would not only match the economic retirement date identified in Duke's endogenous runs, but it may also be able to close the gap towards HB951 compliance across multiple sensitivity cases. In fact, based on Table A-3, if Belews Creek's 2021 coal emissions were removed from Duke's system, this would account for a 10% incremental carbon reduction versus the 2005 baseline.

Q. DO YOU AGREE WITH PUBLIC STAFF'S CONCERN ABOUT RETIRING BELEWS CREEK FROM COAL PRIOR TO 2036?

A. No. Public Staff states that they are "concerned that the decision to retire the Belews Creek units in 2035 was based on an arbitrary target set by Duke Energy Corporation to cease coal generation by 2035, and not on economics." However, this ignores the fact that EnCompass found 2030 to be the economic retirement date for the plant in the P1 scenario. I recognize the heartburn associated with retiring a plant that has received a significant recent capital investment in the form of its partial gas conversion. However, it is important that the Commission not succumb to the "sunk cost fallacy" in this instance. Furthermore, it appears that Duke did not evaluate all of the options for this plant since it failed to include full gas conversion as an option in its modeling, which could enable a later retirement date while also reducing emissions and costs. Based on the information Duke provided thus far, this appears to be a relatively economic option that should be available as an economic selection in the modeling.[47]

Additionally, Public's Staff's suggestion that Duke should ignore the model-selected retirement date and run Belews Creek to 2037 is just as arbitrary as Duke's assumption. In my opinion, it is better to let the model select the

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[47] Strategen Report, p 39.

retirement date. Any transmission deficiencies should be easily addressed ahead of 2030.

Q. REGARDING DUKE'S PROPOSED RETIREMENT DATES FOR MARSHALL 1 AND 2, AND MAYO DO YOU AGREE THAT STRATEGEN'S CRITIQUE "REFLECT[S] A MISUNDERSTANDING OF THE ANALYSIS AND IGNORE[D] THE NEED FOR SUPPORTING INFRASTRUCTURE"?[48]

A. No. Strategen's report clearly considered the Company's purported needs for supporting infrastructure. However, there are many elements of the Strategen report's critique on this issue that Duke's testimony ignored.

Q. DUKE CLAIMS THAT AVOIDING LENGTHY TRANSMISSION UPGRADES AT MARSHALL 1 AND 2 REQUIRES REPLACEMENT GENERATION RESOURCES TO BE ON SITE. HOWEVER, THE COMPANY'S AUGUST 19TH TESTIMONY DISCOUNTS BATTERY STORAGE AS AN OPTION STATING THAT THE REPLACEMENT "MUST BE DISPATCHABLE RESOURCES CAPABLE OF LONGER RUN TIMES TO SATISFY GRID RELIABILITY REQUIREMENTS."[49] DOES THIS MAKE SENSE TO YOU?

A. No. Throughout this proceeding and the 2020 IRP, I have found Duke's responses on this issue to be unpersuasive, and insufficient justification for delaying retirements beyond the economical timeframe. In the 2020 IRP

[48] Snider et al. p 136.
[49] Snider, et al., p 137.

proceeding, Duke explained that transmission upgrades at its retiring coal plants were primarily needed for frequency regulation and voltage support. However, neither of these functions requires a dispatchable resource with a long duration on site. In fact, frequency regulation does not even require that the resource be located on site at all. Duke's testimony was also somewhat evasive regarding the Mayo plant's retirement. Ultimately, however, the Company did not dispute the notion that a 2027 retirement date was achievable, even if challenging to accomplish. One of the reasons Duke provided for delaying retirement was to "take advantage of continued cost declines for declining cost resources, such as batteries."[50] However, this cost decline advantage has been realized now that the IRA will provide a significant reduction in the cost of battery storage virtually overnight via the ITC starting in 2023.

Q. STRATEGEN'S REPORT NOTED THAT CONVERSION OF BELEWS CREEK TO RUN ON 100% GAS AND RETIRING IT FROM COAL PRIOR TO 2035 MAY BE A VIABLE AND RELATIVELY ECONOMIC OPTION. HOWEVER, THIS WAS NOT MODELED AS AN OPTION IN DUKE'S CARBON PLAN ANALYSIS. DID DUKE ADDRESS THIS CRITIQUE IN ITS TESTIMONY?

A. No, the Company did not explain why this option was not modeled. Duke discussed gas conversions more generally stating that such a conversion was "potentially feasible" and that its initial evaluations "did not show favorable

[50] Snider, et al., p 136.

economics."[51] However, I disagree with this characterization. First, these evaluations were not performed as part of the EnCompass modeling which would have more definitively determined whether the economics were favorable. Second as the Strategen report pointed out,[52] the economics of this conversion do appear to be quite favorable compared to other resources additions Duke considered in the Carbon Plan.

VI. NEAR-TERM PROCUREMENT ACTIVITY: SOLAR, SOLAR PLUS STORAGE, STANDALONE STORAGE, ONSHORE WIND, AND NATURAL GAS GENERATION

A. The IRA bolsters the rationale for near-term solar, wind, and battery storage resources, but calls into question near-term procurements of natural gas.

Q. DO YOU HAVE ANY RECOMMENDATIONS FOR THE COMMISSION REGARDING DUKE'S NEAR-TERM PROCUREMENT ACTIVITIES BASED ON THE PASSAGE OF THE IRA?

A. Yes. I believe the IRA further cements the notion that near-term procurement of solar, wind, and battery storage in the 2023-2030 timeframe is a "no regrets" strategy for any Carbon Plan. In contrast, the Commission should not use any approved Carbon Plan to inform any future CPCN proceeding for new gas

[51] Snider, et al., p 140.
[52] Strategen Report, p 39.

resources unless and until the IRA can be fully incorporated into the portfolio modeling process.

In considering Duke's Proposed Near-Term Actions, the procurement of 3,100 MW of solar, 1,600 MW of battery storage, and 600 MW of onshore wind are likely to be under-estimates, if anything, of the optimal quantity for these resource types. Meanwhile, the passage of the IRA calls into question whether procurement of new natural gas – particularly new CC units – is part of the economically optimal portfolio and whether a CPCN should still be pursued in 2023, if at all.

Q. WILL THE COMMISSION BE ABLE TO ADDRESS THE CPCN ISSUE BY SIMPLY INCORPORATING THE IRA INTO IN ITS ANALYSIS IN THE NEXT CARBON PLAN CYCLE?

A. Not if the Carbon Plan will be relied on to inform CPCN determinations regarding gas resources. In its August 19, 2022 testimony, Duke continued to express its intent to pursue CPCN applications for new gas plants in 2023. This was based on its Supplemental Carbon Plan analysis which does not reflect the IRA. If the Commission accepts the analysis without fully considering the IRA, then it would lock in a potentially sub-optimal resource investment and increase costs and risks to customers for decades to come.

B. Near-term procurement of solar, battery storage, and onshore wind should proceed as "no regrets" options.

Q. WHAT ARE YOUR KEY RECOMMENDATIONS REGARDING DUKE'S NEAR-TERM PROCUREMENT ACTIVITIES?

A. Given the modeling concerns described above, it is premature for the Commission to adopt any of the Initial Portfolios proposed by Duke as is, and premature to approve all of the near-term actions Duke has proposed. This is also true for the Supplemental Portfolios (SP5 and SP6). Instead, I recommend that the Commission consider the SP-AGO portfolio, which addresses the remainder of issues described in this testimony and in the AGO's initial comments, and which were not addressed in SP5 or SP6.

However, even if the Commission adopts a Carbon Plan without considering any further modeling, the Commission should, at a minimum, consider certain actions for each resource type as part of any near-term action plan adopted.

Q. DO YOU SUPPORT ANY OF DUKE'S NEAR-TERM PROCUREMENT ACTITIVITES?

A. Yes. I believe there is a sufficient basis to move forward with a minimum amount of solar, storage, and onshore wind procurements, and that these resources are still likely to be selected in any revised model run. This is especially true in light of the recent passage of the IRA, which has extended the federal ITC and PTC for renewable resources through 2032 rather than phasing them down as was the case prior to the legislation. Moreover, the ITC now applies to standalone battery storage, rather than being limited to storage co-located with renewable resources. Thus, the solar, storage, and wind procurements that Duke has identified in its proposed near-term action plan should still be pursued as part of a "no regrets" strategy. In fact, greater quantities of these resources may be warranted due to the IRA. Meanwhile, any solicitation for solar plus storage resources should consider configurations beyond those modeled by Duke in its plan, as a means to maximize limited interconnection space.

Q. DO YOU HAVE ANY ADDITIONAL RECOMMENDATIONS REGARDING DUKE'S NEAR-TERM PROCUREMENT OF BATTERY STORAGE RESOURCES?

A. Yes. As discussed in Section V, Duke should seek to site battery storage at retiring coal facilities (e.g., Marshall 1 and 2, Mayo) as replacement generation by 2025 to avoid transmission upgrade requirements and advance economic retirements in the 2026 timeframe. Furthermore, Duke should explore opportunities to take advantage of new DOE financing opportunities under the IRA designated for infrastructure investments at retiring generation sites.

B. It is premature to pursue near-term procurement of new natural gas generation and the role of new natural gas units as part of the Carbon Plan should be further examined in 2023 or 2024 (i.e., the next Carbon Plan cycle).

Q. DO YOU HAVE ANY CONCERNS WITH DUKE'S NEAR-TERM PROCUREMENT OF NATURAL GAS GENERATION?

A. Yes. As described in Section IV, Duke's modeling (both initial and Supplemental) had several limitations that likely led to additional natural gas generation at the expense of other resources. As demonstrated in the SP-AGO portfolio, once those problems were corrected, less natural gas generation was selected and therefore procurement could be minimized or delayed. All four of Duke's initial portfolios (P1-P4) as well as both Supplemental Portfolios (SP5 and SP6) included 2,400 MW of new natural gas CC additions in the 2029 timeframe. Given this lack of variation, and the magnitude of this investment, it is important to understand what the underlying drivers are, and whether potential alternatives were sufficiently represented and allowed to compete in the model selection process. Perhaps even more importantly, the Commission should determine whether the magnitude of proposed gas investments is reasonable to pursue in the face of scarce fuel supplies and uncertainties around the cost and availability of firm transport on existing pipelines.

CC units are more capital intensive than other types of gas units like CTs and are therefore less suitable for strictly meeting peak capacity needs; however, they are more operationally efficient and thus more suitable for meeting energy needs. Due to this efficiency, CC units are designed to operate with higher capacity factors relative to CTs, and thus will contribute more significantly to carbon emissions, potentially making HB951 compliance more challenging. Based on Duke's modeling, it appears that some amount of new gas may be needed in the Carbon Plan portfolio. However, the question of "how much," "what type," and "when" these additions will be needed is less clear. This uncertainty is further magnified by the passage of the IRA as I explained in Section III above. At this point in time, I believe it is premature to determine what role natural gas generation should play in the Carbon Plan and premature for Duke to pursue a new CPCN in 2023, especially for new CCs, and that such considerations should be deferred until a later date. If the Commission chooses to adopt a plan with new CCs, this plan should be limited in this cycle to no more than one 800 MW facility, consistent with Duke's initial No App Gas case.

Q. DO YOU AGREE WITH PUBLIC STAFF'S FINAL RECOMMENDATION TO APPROVE 1,200 MW OF NEW NATURAL GAS COMBINED CYCLE UNITS AS PART OF DUKE'S NEAR-TERM ACTIONS?[53]

A. No. In fact, I am surprised that Public Staff ultimately recommended this given the significant concerns raised about new gas throughout their comments. These include concerns regarding future natural gas fuel supply, proposed hydrogen conversion, arbitrarily constrained options for new gas resources in the model selection (*i.e.*, only 1,200 MW resources can be selected, versus 1,200 or 800 MW resources), and so on. Furthermore, any preference Public Staff may have had for new gas resources needs to be thoroughly reconsidered in light of the IRA.

Q. DO YOU AGREE WITH TECH CUSTOMERS' OBSERVATION THAT A GREATER SHARE OF POWER PURCHASE AGREEMENTS

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[53] Public Staff Comments, p 153.

("PPAS") VERSUS UTILITY-OWNED GENERATION COULD INCREASE PLANNING FLEXIBILITY AND REDUCE COSTS?

A. Yes. In my experience, it is typical for PPA projects procured through a competitive bidding process to be lower in cost than utility-owned generation. In fact, it is my understanding that Duke's analysis includes a reduction in solar resources costs of about [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] to account for the share of solar resources that are procured from PPAs (*i.e.*, 45% of the total).[54]

Thus, to the extent the Commission has the flexibility to authorize or even require PPAs for a share of solar resource greater than 45%, this could produce substantial cost savings to Duke customers. The same is true for all other resources that could be procured as PPAs through a competitive process, including wind, battery storage, and even natural gas. As such, I recommend the Commission pursue all avenues to seek competitive procurements, beyond 45% of solar resources.

Q. DO THE RESULTS OF THE SP-AGO ANALYSIS SUPPORT THE CONCLUSIONS YOU DESCRIBED ABOVE?

A. Yes. The results indicate that new gas CT resources are not needed until the end of 2028 and can therefore be considered at a later date when the full effects of the IRA can be analyzed. Furthermore, the results indicate that new gas CC resources may not be needed at all. Finally, the results indicate that addition of

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[54] Duke Energy Response to Public Staff DR 16-4.

additional solar plus storage configurations and wind imports are beneficial – both of which could be facilitated through competitive PPA solicitations.

VII. NEAR-TERM DEVELOPMENT ACTIVITIES: LONG-LEAD TIME RESOURCES

A. The Commission should consider the varying levels of technology readiness when evaluating each of Duke's proposed long-lead time resources.

Q. PLEASE SUMMARIZE YOUR KEY RECOMMENDATIONS RELATED TO DUKE'S PROPOSED NEAR-TERM DEVELOPMENT ACTIVITIES FOR LONG-LEAD TIME RESOURCES.

A. If completed, each of the long-lead time resources proposed by Duke would provide unique value to Duke's system and could contribute significantly to achieving the carbon reduction policy. However, they are all very costly resources, and should not be approved lightly by the Commission. As described below, these resources also all carry significant execution risk due to lengthy and complex siting and permitting challenges. As such, there should be some awareness about the varying uncertainties that these resources bring which could cause them to be delayed or cancelled.

Q. DO YOU SUPPORT ANY OF THE PROPOSED NEAR-TERM DEVELOPMENT ACTIVITIES FOR LONG-LEAD TIME RESOURCES?

A. Yes. In my view, the one of these resources with the most certainty is pumped hydro. Pumped hydro is a mature technology with a well proven track record and is widely deployed across the U.S. Thus, from an execution risk standpoint, it may make sense to approve further development activities for this resource.

Similarly, offshore wind has a proven track record in Europe, but not yet in the U.S. I recommend that the Commission apply more caution in approving development activities for this resource but I recognize it may make sense to move forward due to the significant amount of carbon-free energy that offshore wind can generate, and its ability to complement solar in terms of the timing of when energy is produced.

Q. WHAT DO YOU RECOMMEND REGARDING THE NEAR-TERM DEVELOPMENT ACTIVITIES FOR SMALL MODULAR REACTORS?

A. Small modular reactors ("SMRs") are an unproven technology and could carry significant risk to Duke's customers in the event of cost overruns, which have been common among recent nuclear projects in the U.S.[55] Given the lack of commercial SMR deployments to date, and the recent history of cost overruns which have more than doubled the cost in some cases, I believe that some of Duke's capital cost assumptions may be overly optimistic.

The Commission should use extreme caution in approving any development activities for new nuclear and ensure that all other options have been explored

[55] See for example: Jeff Amy, Georgia nuclear plant's cost now forecast to top $30 billion (May 8, 2022), https://apnews.com/article/business-environment-united-states-georgia-atlanta7555f8d73c46f0e5513c15d391409aa3.

first. Further, the AGO has recommended that cost recovery issues be addressed in a different proceeding. I also recommend that the Commission order Duke to model a contingency plan in the event that new SMR resources are not able to be developed within Duke's proposed timeframe.

B. Preliminary development activities can proceed, but the Commission should not address cost recovery issues in this proceeding.

Q. PUBLIC STAFF APPEARS TO BE SUPPORTIVE OF NEW NUCLEAR SMR RESOURCES AS A KEY COMPONENT OF THE CARBON PLAN. DO YOU HAVE ANY CONCERNS ABOUT THIS?

A. Yes. Most of these concerns were already expressed in the Strategen Report. However, it is worth noting that Public Staff points to PacifiCorp's demonstration project in Wyoming as an example of where else SMR projects are being developed. It is worth a degree of caution in referring to this project as a near-term example of SMR deployment. The Oregon PUC specifically chose not to include this project in its acknowledgement of PacifiCorp's most recent IRP.[56] This was in part due to concerns raised by intervenors about the cost, risk, and aggressive timeline of the proposed project.

VIII. WORK ON EXISTING RESOURCES

[56] OPUC Order No. 22-178, https://apps.puc.state.or.us/edockets/orders.asp?OrderNumber=22-178.

A. Duke's proposed work to expand flexibility of the existing gas fleet and pursue SLRs is reasonable.

Q. AT A HIGH LEVEL, DO YOU SUPPORT DUKE'S PROPOSAL TO PURSUE "EXPANDING FLEXIBILITY OF THE EXISTING GAS FLEET AND CONTINUED DISCIPLINED PURSUIT OF SLRS"?

A. Yes. Enhancing the flexibility of existing gas units could be an effective method of aiding renewable resource integration without needing to invest in new generation. Similarly, extending the life of existing nuclear plants will significantly minimize the challenge of meeting the Carbon Plan's requirements.

IX. TRANSMISSION PLANNING, PROACTIVE TRANSMISSION, AND RZEP

A. Consolidation of Balancing Areas ("BAs") is beneficial for a variety of reasons.

Q. DO YOU AGREE WITH PUBLIC STAFF'S SUGGESTION THAT DUKE SHOULD BEGIN STEPS TO CONSOLIDATE ITS BAS?

A. Yes. Consolidation of BAs is important for a variety of reasons, including the fact that this will aid in the integration of variable resources, improve operational efficiency and reduce related operating costs, and enhance reliability. This is affirmed by NCSEA, et. al, who explain that combining the DEP and DEC balancing areas could dramatically affect the resources required in Duke's Carbon Plan.

B. Several of Public Staff's suggestions related to transmission planning are reasonable, however, hurdle rates should not persist over the long run.

Q. DO YOU AGREE WITH PUBLIC STAFF'S RECOMMENDATION THAT RZTEP COSTS SHOULD BE INCLUDED IN THE PVRR CALCULATIONS GOING FORWARD?

A. Yes. It is important to evaluate Carbon Plan options wholistically, including both generation and transmission costs. In addition to RZTEP, it is important that capital costs associated with other resources are fully accounted for in the same manner. For example, existing coal plants are subject to ongoing incremental capital expenditures that can be on par with new generation facilities. Similarly, existing and new gas plants are subject to incremental fixed costs associated with firm transportation of fuel supply. Thus any attempt to include RZTEP costs in the PVRR calculations should ensure the same treatment is applied to these other fixed cost categories.

Q. DO YOU AGREE WITH PUBLIC STAFF'S SUGGESTION THAT A 20-YEAR TRANSMISSION PLAN SHOULD BE CONSIDERED GOING FORWARD?

A. Yes. This is consistent with emerging practices of many other large system operators around the US.

Q. DO YOU HAVE ANY GENERAL THOUGHTS ON PUBLIC STAFF'S RECOMMENDATIONS REGARDING TRANSMISSION PLANNING AND RELATED COSTS?

A. Yes. I believe Public Staff has many good recommendations regarding transmission planning that the Commission should consider. However, as a general matter, I believe that Public Staff and Duke are too focused on transmission upgrades within Duke's own footprint rather than considering how the regional transmission network can be improved to better integrate regional resources into Duke's system. As discussed in Strategen's report, nearly all of the recent studies on cost-effective integration of high levels of clean energy conclude that such regional coordination is essential.

Q. DO YOU AGREE WITH PUBLIC STAFF'S SUGGESTION THAT INTERTIES BETWEEN DEC AND DEP "CANNOT BE MODELED FOR FIRM CAPACITY TRANSFERS TO SATISFY EACH COMPANY'S RESERVE MARGIN"?

A. Not exactly. While this may reflect current reality, this does not mean firm transfers cannot be modeled. Moreover, limitations on firm transfer is a condition that the Commission should seek to remedy going forward. Consolidation of BAs brings many benefits, not the least of which is the ability to share resources over a wider region, which can enhance reliability and lower overall costs. As Duke has testified, the 2026-2027 timeframe could be a reasonable target date for this consolidation which would align with the near-term resource additions being considered in the Carbon Plan.

Q. DO YOU HAVE ANY THOUGHTS ON PUBLIC STAFF'S RECOMMENDATION REGARDING APPLYING A HURDLE RATE TO ENERGY TRANSFERS BETWEEN DEC AND DEP?

A. Similar to my comments above, I believe it is possible to envision a near-term future where the BAs are consolidated and such a hurdle rate would no longer apply, and therefore does not need to be modeled. However, I believe Public Staff's suggestion is useful for considering potential resources outside of the DEC and DEP BAs. More specifically, resources located outside of Duke's service territory could be delivered to Duke via the current FERC-approved non-Firm service annual $/kWh as found in the publicly available OATT for each utility. This is consistent with my earlier recommendation for consideration of wind imports.

C. The Commission should require Duke to identify "low hanging fruit" opportunities to increase the resource injection capability of any major transmission upgrade.

Q. BEYOND PROACTIVE TRANSMISSION PLANNING FOR MAJOR GRID UPGRADES, ARE THERE LOW-COST WAYS TO INCREASE INJECTION CAPABILITY OF THE GRID?

A. Yes. As one recent example I am familiar with, Tri-State Generation and Transmission in Colorado recently sought several major new additions to its transmission system costing over $400 million to accommodate 400 MW of new renewable energy resources to be connected as part of its Responsible Energy Plan.[57] As part of a settlement agreement approving the new transmission lines, Tri-State agreed to conduct a follow-on study to identify

[57] Colorado PUC Proceeding No. 22A-0085E.

incremental transmission improvements that could increase the injection capabilities of the new lines and thus allow even more renewable resources to be connected. The results of the study showed that a modest incremental investment of approximately $270,000 could allow up to an additional 430 MW to be injected. Thus, the study revealed significant low-cost "low hanging fruit" in incremental improvements that could be made to maximize the injection capability of the new lines. While every transmission system is different, it is certainly possible similar circumstances could arise on Duke's system through its proactive transmission planning process. Thus, I recommend that the Commission require Duke to follow a similar practice in its transmission planning whenever major new upgrades are identified and pursued. This will help minimize the execution risk of adding significant amounts of new solar to the Duke system.

X. EE/DSM ISSUES/GRID EDGE

A. Duke selected an ambitious but reasonable level of UEE in its Carbon Plan.

Q. HOW DID DUKE ADDRESS EE/DSM IN ITS PROPOSED CARBON PLAN?

A. In its proposed Carbon Plan, Duke stated that it intends to pursue utility-implemented EE/DSM measures ("UEE") that collectively achieve savings of 1% of eligible retail load annually. After this 1% level of UEE was selected, it was embedded in the load forecast that Duke subsequently used to conduct its analysis in EnCompass for selecting supply-side resources. While Duke did evaluate a Low Load sensitivity that contemplates a higher level of UEE achievement equivalent to annual savings equal to 1% of all retail load (rather than "eligible" retail load), the Company did not conduct any calculations on the cost or performance of this sensitivity case.

Q. WHAT ARE YOUR CONCERNS WITH HOW DUKE ADDRESSED EE/DSM IN ITS PROPOSED CARBON PLAN?

A. I have several concerns with how Duke addresses UEE in its proposed Carbon Plan. First, Duke's target is not as ambitious as it could be, even for eligible load. Notably, several states have consistently achieved annual EE/DSM savings of 1% or higher, with 14 states doing so in 2019 and some states even exceeding 2% savings.[58] Second, by incorporating UEE savings as part of its load forecast, the amount of UEE resource Duke has proposed is essentially fixed or "forced-in" prior to the model. As such, there is no way to assess whether a different amount of utility investment in these UEE measures would have been warranted and could have led to a lower cost portfolio. Third, Duke's approach to UEE Roll Off is concerning to me and suggests that there may be underlying problems with Duke's initial load forecast. Finally, Duke's proposal to use an "as-found" baseline does not accurately reflect incremental UEE savings and has potential unintended consequences.

Q. WHAT WOULD BE A MORE REASONABLE UEE TARGET?

A. I believe a scenario consistent with Duke's Low Load sensitivity may be a more reasonable target. This is especially true in light of the passage of the IRA which

[58] See ACEEE 2020 State Energy Efficiency Scorecard, https://www.aceee.org/research-report/u2011.

includes a plethora of new tax incentives and rebates. Some estimates have suggested that this could amount to $14,000 in efficiency upgrades for each individual homeowner. While some of these might be pursued absent UEE programs, they will have the same effect, and UEE programs can leverage these opportunities to make EE/DSM measures even more compelling to prospective participants.

Q. DO YOU HAVE ANY RESPONSE TO PUBLIC STAFF'S CONCERNS ABOUT DUKE'S ASSUMPTION OF ACHIEVING 1% EE AND RELATED LEGISLATIVE CHANGES THAT MAY BE REQUIRED?

A. Yes. First, as a preliminary matter, I believe the main concern with the potential for EE/DSM underperformance is due to the fact that North Carolina allows commercial and industrial ("C&I") customers to opt-out of both funding and participating in EE programs, even though they continue to benefit from residential customers' participation in these programs. However, it is worth noting that opting out of these programs is a choice, not a requirement, for larger customers. If Duke were to offer EE/DSM programs that were actually attractive to C&I customers, then there is the possibility that these customers would opt back in as a means to reduce their energy bills over the long run. In my experience, many utilities are not always highly motivated to offer comprehensive EE/DSM programs to their customers unless directed to do so by the Commission. In North Carolina's case, although there is an opt-out provision, the Commission may still have the latitude to direct Duke to improve its C&I offerings even if participation is not compulsory. Meanwhile, there are successful examples of C&I programs that can be drawn upon from other regions (*e.g.*, the Pacific Northwest).

Second, Public Staff is concerned that Duke's approach veers outside of the normal Market Potential Study approach that is commonly used by utilities. However, it is worth noting that Market Potential Studies are not without flaws. In general, they are an exercise in winnowing down the EE/DSM considered to be available; however, they also contain subjective choices. For example, the maximum level of incentive deemed allowable for certain measures can be a key factor (and a subjective choice) determining the "achievable potential" versus the "economic potential."

Third, it is worth noting that no other resource considered by Duke (*e.g.*, natural gas, nuclear) must pass a cost-effectiveness test in the same manner that EE does. Given the new planning paradigm of HB951, which prioritizes carbon-free resources like EE, it may be worthwhile to consider a more flexible approach to EE cost-effectiveness. For instance, Duke has proposed a new approach to cost-effectiveness evaluation that considers other carbon-free portfolio resources beyond those that have been typically used in the past. This is an appropriate development.

Fourth, there are significant new tax incentives and rebates for energy efficiency included in the IRA that could be leveraged as part of any UEE program offering going forward.

Finally, I do share some of Public Staff's concerns with Duke's high reliance on behavioral EE programs to meet its obligations. As such, I believe there should be a concerted effort to supplement these behavioral programs with increased investment in non-behavioral EE that includes longer lasting measures.

B. Going forward, the Commission should consider improvements to how the appropriate level of UEE is determined. These issues should be addressed in future Carbon Plans and/or other EE/DSM-related proceedings.

Q. WHAT WOULD BE A MORE REASONABLE WAY TO MODEL UEE?

A. It would be technically feasible for Duke to model different amounts of UEE as a selectable resource in EnCompass. In fact, Strategen has had experience doing this as part of other utility resource planning processes in recent years where a 70% target was also being considered. Generally speaking, this practice led to more EE/DSM measures being selected than was previously assumed by the utility. This is not surprising since UEE are often the lowest-cost resource available, let alone the lowest-cost carbon free resource. EE/DSM portfolios also tend to match the utility's load shape and can be considered akin to a "baseload" resource.

Because Duke did not model UEE as a resource that could be selected by the EnCompass model, neither the base level of UEE included in all of Duke's portfolios nor the higher amount included in the Low Load sensitivity are likely to represent the most optimal level of UEE from both a cost perspective and a carbon emissions reduction perspective. For example, it may be more cost effective to increase UEE rebate/incentive levels (even beyond those levels considered in the market potential studies) to achieve greater deployment of EE/DSM measures if doing so were able to avoid or defer more expensive carbon-free resources. While this additional step may not be feasible in the current Carbon Plan cycle, I recommend that this be explored in future iterations of the Carbon Plan.

Q. DUKE DISAGREED WITH THE AGO'S RECOMMENDATION FOR ALLOWING UEE TO BE A SELECTABLE RESOURCE, STATING THAT "MODELING A RESOURCE THAT IS ALMOST ENTIRELY DEPENDENT ON CUSTOMER PREFERENCES AND PARTICIPATION AS A SELECTABLE RESOURCE IS PROBLEMATIC"[59] HOW DO YOU RESPOND?

A. While it is true that efficiency measures are the result of customer decisions, it is not true that Duke and other utilities have zero ability to influence the outcome of these decisions. For example, Duke has control (with Commission authorization) over the level of rebates or incentives it offers for efficient

[59] Snider, et al., p 124.

appliances. In this sense incentive levels and resulting UEE program budgets can be tuned to increase (or decrease) the level of UEE that reflects the optimal Carbon Plan. This could readily be modeled as a selectable resource by selecting among different levels of UEE deployment, and corresponding program budgets for each deployment, within EnCompass. The same principle could also apply for NEM resources.

Q. WHAT WOULD BE A MORE REASONABLE APPROACH TO COUNTING UEE SAVINGS?

A. Even if UEE rebate/incentive levels were increased to cover the full incremental measure cost—or more—it is possible that they would still be less costly than other more expensive carbon-free options modeled by Duke, such as nuclear SMR. Traditionally, EE/DSM cost-effectiveness tests have relied on proxy supply resources that are usually in the form of a natural gas plant as a way to determine the benefits of avoiding incremental supply-side resources. However, under a Carbon Plan framework, the comparable resource may no longer be a gas plant and instead may reflect other options. For this reason, I am generally supportive of Duke's proposal to modify the Cost-Benefit test, as described in Appendix G, with the understanding that there are more detailed changes still to be made.

C. Duke's approach to UEE Roll Off and "naturally occurring efficiency" is likely inflating its underlying load forecast.

Q. PLEASE EXPLAIN DUKE'S APPROACH TO UEE ROLL OFF.

A. As part of the development of the load forecast used in its Carbon Plan, Duke has projected the long-term effects of UEE measures. Duke's approach to "UEE Roll Off" whereby the initial effects of UEE measures are essentially removed after a period of time. For example, in 2030 this "roll off" effect erases nearly half of the load reduction attributable to incremental UEE implemented by DEC.

Q. DID DUKE EXPLAIN WHY THEY TOOK THIS APPROACH?

A. Yes. Duke explains that "As UEE serves to accelerate the timing of naturally occurring efficiency gains, the forecast 'rolls off' or ends the UEE savings at the conclusion of its measure life."

Q. WHY IS DUKE'S UEE ROLL OFF APPROACH NOT REASONABLE?

A. Duke's approach would be acceptable if the underlying load forecast also evolved over time to reflect the "naturally occurring efficiency gains" that Duke describes in tandem with the UEE roll off. In other words, the baseline appliance efficiency trends will improve over time, leading to declining energy usage per customer, even without UEE effects. In this sense, the "rolled off" UEE benefits will persist, but they will be separately accounted for as part of the fundamental load forecast, not as part of the UEE program.

In principle, Duke seems to agree with this, stating that "the naturally occurring appliance efficiency trends replace the rolled off UEE benefits serving to continue to reduce the forecasted load resulting from energy efficiency adoption."[60] However, these statements do not appear congruent with the actual load forecast data that Duke provided. Rather than showing a trend towards declining consumption due to "naturally occurring efficiency," Duke actually forecasts an increase in usage per customer for DEC.[61]

Q. DO YOU THINK THIS CALLS INTO QUESTION DUKE'S UNDERLYING GROSS LOAD FORECAST, PRIOR TO ADJUSTMENTS?

A. Yes. Duke's testimony stated that "most intervenors do not appear to take issue with the process utilized to develop the gross peak demand forecast."[62] However, the AGO/Strategen did raise concerns about the underlying forecast in its July comments and report. If the underlying approach is found to be incorrect it could have a significant effect on the overall load forecast, and could significantly decrease the overall resource need regardless of which Carbon Plan portfolio is selected.

Q. DUKE WITNESS DUFF TESTIFIES THAT STRATEGEN'S RECOMMENDATIONS REGARDING UEE ROLL-OFF ARE INCORRECT BECAUSE "LOAD IMPACTS OF EV ADOPTION AND BENEFICIAL ELECTRIFICATION ARE INCLUDED IN THE LOAD FORECAST, WHICH CAN MORE THAN MASK THE EE ROLL-OFF

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[60] Duke Carbon Plan, Appendix F, p. 5.
[61] *See* Strategen Report, p 42-43.
[62] Snider, et al., p 117.

BEING REFLECTED IN USAGE PER CUSTOMER."[63] HOW DO YOU RESPOND?

A. Witness Duff's testimony directly contradicts a response that Duke provided to a data request.[64] According to the data request response provided to the AGO, the impact of EV adoption, behind-the-meter solar, and energy efficiency programs are not included in the underlying "before impacts" load forecast. The underlying load forecast is then modified based on projections for those items. This is also consistent with the way the Company described the process in its initial Carbon Plan filing:

> The Companies develop the Load Forecast in four steps: (1) a service area economic forecast is obtained; (2) an energy forecast is prepared by estimating statistical models based on these economic conditions; (3) ex post modifications that account for the growth in electric vehicle, solar and energy efficiency programs must be considered; and (4) using the energy forecast, summer and winter peak demand forecasts are developed.[65]

Therefore, the underlying "before impacts" should show a declining per customer usage as UEE is rolled off. However, as explained in more detail in the Strategen report, it does not.[66]

Q. DO YOU AGREE WITH PUBLIC STAFF'S ASSESSMENT THAT DUKE DID NOT SUFFICIENTLY OR TRANSPARENTLY EXPLAIN

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[63] Direct Testimony of Lon Huber and Tim Duff for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Docket No. E-100, Sub 179 (Aug. 19, 2022), p 18-19.
[64] Duke Energy Response to AGO DR 6-4 (attached as Exhibit 5).
[65] Duke Energy Carbon Plan, Appendix F at p 1.
[66] Strategen Report at pp 42-43.

HOW IT CONSIDERED "MARKET TRANSFORMATION"[67] OF ENERGY EFFICIENCY MEASURES?

A. Yes. As was explained in the Strategen report,[68] and in the discussion above on UEE Roll Off, it is not clear how Duke ultimately incorporated "naturally occurring efficiency" into its load forecast as this market transformation occurs. In fact, the trends in this regard appear counterintuitive and should be closely examined by the Commission in this and all future resource planning exercises.

D. Duke's proposal to move towards an "as-found" baseline methodology should be rejected.

Q. PLEASE EXPLAIN DUKE'S PROPOSED "AS-FOUND" BASELINE.

A. Duke proposes to change the method for calculating the savings associated with UEE. Currently, when evaluating UEE program performance, the level of UEE savings attributable to the installation of a more efficient appliance is calculated in comparison to the level of energy consumption for a baseline appliance, which is meant to reflect what is generally available in the market at the time. This baseline performance is typically informed by the minimum efficiency and performance requirements set by the federal or state level codes and standards, since these generally dictate the baseline efficiency of appliances being offered in the market.

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[67] Public Staff Comments, p 58.
[68] Strategen Report, p 42.

Duke proposes shifting to an "as-found" baseline methodology, which would erroneously compare the energy consumption of the newly purchased appliance to that of the broken one being replaced (*i.e.*, the "as found" appliance). In doing so, Duke's method would include fictitious energy savings in its accounting since, realistically, the only available replacement options would be at today's baseline level of efficiency, not the old appliance's level of efficiency.[69]

Q. WHY IS DUKE'S APPROACH NOT REASONABLE?

A. Duke's new "as-found" method is problematic for several reasons. First, by setting the obsolete appliance as the baseline, Duke would be able to claim UEE savings for installing the most *in*efficient appliances the market has to offer—appliances which only meet the bare minimum of prevailing standards.

Additionally, while Duke claims that the "as found" approach will increase the overall amount of UEE savings achieved, the opposite is true. By simply increasing the kWh savings attributable to each measure, but not actually increasing the actual efficiency of the measures being installed, Duke will simply be artificially inflating the amount of savings counted for each measure. This means that Duke will be able to reach its 1% savings target with fewer overall measures being deployed than it would have needed under the traditional baseline accounting method.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE "AS-FOUND" BASELINE?

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[69] *See* Strategen Report, p. 43-44.

A. I recommend that the Commission reject Duke's proposal to move to the "as-found" methodology outlined in its proposed Carbon Plan. Instead, the Commission should maintain the current approach to counting EE savings using the minimum federal efficiency and performance requirements.

E. Future carbon plans should include a more comprehensive evaluation of different levels of distributed energy resources, including steps to achieve these levels.

Q. PLEASE EXPLAIN HOW NET ENERGY METERING AND DISTRIBUTED GENERATION WERE TREATED IN DUKE'S PROPOSED CARBON PLAN.

A. As it did with EE/DSM, Duke embedded net energy metering ("NEM") resources into its load forecast as a fixed input, rather than allowing it to be a selectable resource to explore different levels of deployment. While Duke did develop both a "Base NEM" and a "High NEM" case as part of its load forecast, it is not clear how these two cases were ultimately used by Duke or compared in the final portfolios.

Q. ARE THE "BASE NEM" AND "HIGH NEM" SCENARIOS SUFFICIENT?

A. No. These two cases represent a relatively narrow set of possibilities.

Q. WOULD IT HAVE BEEN REASONABLE FOR DUKE TO INCLUDE MORE DISTRIBUTED GENERATION IN ITS PROPOSED CARBON PLAN?

A. Yes. Duke's proposed plan could have done more to evaluate different levels and forms of distributed generation. This is especially true in light of the fact that Duke has expressed significant concerns about the limitations on larger scale solar resources to achieve interconnection status on its transmission grid. For distributed solar, there may be fewer barriers to achieve interconnection status which means distributed solar could serve as an important complement to large scale projects.

In his direct testimony, Duke witness Snider stated that "Duke Energy's projections of NEM adoption are in line with recent trends. It is true that both future state and federal policy changes may change these trends, but until there is more certainty, Duke Energy agrees with the Public Staff that the point-in-time NEM forecast used in the Carbon Plan is appropriate for planning purposes." As explained above, the IRA is a major federal policy change and provides significant new financial incentives for customers to pursue distributed resources in the form of both solar and battery storage. If customers are willing to make significant personal investments in distributed generation, the Commission should seek to leverage that willingness as much as possible to add low cost, carbon free generation.

Q. WHAT WOULD BE A MORE REASONABLE WAY TO INCLUDE NEM IN THE CARBON PLAN?

A. It might be possible to consider NEM resources as selectable resource in EnCompass and scale the associated costs accordingly. Notably, Duke has recently proposed a novel approach to distributed solar that would potentially couple it with other EE/DSM measures (*e.g.*, smart thermostats) and time-of-use pricing. As such, it might be possible to consider different levels of distributed solar deployment based on incentive levels associated with this offering. Duke should consider steps to ensure the additional grid benefits from offerings like this are fully captured. In addition, Duke should seek to analyze new potential offerings. For example, if distributed solar is coupled not only with a smart thermostat, but also with a battery storage system, or managed EV charging, then the effects on the load shape could be significantly improved over standalone solar. This could potentially provide much greater capacity and/or energy benefits during peak hours. As such, I recommend that in the next Carbon Plan cycle, Duke evaluate a larger variety of distributed generation offerings beyond simply NEM. This is especially important in light of the IRA which is likely to accelerate adoption of distributed solar and storage beyond what Duke assumed in its proposed Carbon Plan.

XI. RELIABILITY

A. The Commission should continue to develop and monitor reliability metrics as part of its future Carbon Plan evaluation process.

Q. DO YOU AGREE WITH PUBLIC STAFF'S ANALYSIS REGARDING THE MAGNITUDE OF "NET LOAD RAMPS" AND "CC STARTS" AS INDICATORS OF SYSTEM RELIABILITY WHEN COMPARING PORTFOLIOS?

A. Partially. I agree that these two metrics are useful indicators for how the system might perform under different scenarios. However, in isolation they are not meaningful for evaluating system reliability. Neither ramping nor unit starts are the primary reliability metrics that are typically evaluated by system planners and operators (*e.g.*, LOLE, EUE, etc.). Furthermore, it is necessary to consider both of these metrics in the context of other system limits. For example, even if net load ramps increase, it is not clear when or if these ramps would exceed the total flexible ramping capability available on Duke's system. Developing transparent metrics around ramping capability and ramping needs will be an important step for the Commission to consider going forward. Additionally, any evaluation of these metrics needs to consider steps that are currently being implemented, or could be implemented, that would mitigate their effects. For example, meaningful steps towards regional market operation could have a significant effect on mitigating the cost and reliability impacts of net load ramps.

XII. EXECUTION RISKS

A. All resources carry some degree of execution risk and solar is not unique in this regard.

Q. WHAT ARE YOUR RECOMMENDATIONS RELATED TO EXECUTION RISKS?

A. In the AGO's initial comments and Strategen report, the AGO and Strategen recommended that the Commission consider a 2030 target date for compliance versus a later date (e.g. 2032 or 2034) as a means to provide greater optionality if execution challenges emerge. I recognize that targeting an earlier compliance date creates significant potential execution risk due to the shorter timeline for developing new resources, including unprecedented amounts of new solar. However, it is important to recognize that solar is not unique in terms of having significant execution risks. For example, additional natural gas additions have execution risk if new pipeline capacity for firm fuel supply is not secured. Small nuclear reactors and green hydrogen generation have execution risks if research and development do not proceed as quickly as anticipated or if costs do not reach predicted levels. Battery storage has supply chain risks that could delay deployment. EE/DSM carries risks in terms of customer participation levels achieved. Finally, the presumption that new CTs will operate on ULSD at least some of the time will add to their emissions contribution, thus introducing potential execution risk in terms of obtaining necessary air permits.

Q. HOW WOULD YOU CHARACTERIZE PUBLIC STAFF'S ASSESSMENT OF THE VARIOUS CARBON PLAN PORTFOLIOS THAT DUKE PROPOSED?

A. Public Staff was less favorable towards Portfolio 1 due to its higher cost and potentially higher execution risks. Meanwhile, Public Staff was more favorable towards Portfolio 4 due to it being the "most achievable."[70]

Q. DO YOU THINK THIS IS A FAIR CHARACTERIZATION?

A. No. First, it should be no surprise that Portfolio 4 might appear to be the "most achievable" but that is simply due to the fact that it has the most delayed

[70] Public Staff Comments, p 19.

compliance deadline (*i.e.*, 2034 versus 2030). However, the Commission should not equate "most achievable" with "most preferred." It may be better to aim high and miss the mark by a year or two, rather than aim low out of an over-abundance of caution, and fail to meet the statutory requirements.

Second, any concerns about costs due to accelerated deployment of solar and battery storage needs to be re-evaluated in light of the IRA, which will significantly reduce the costs of both resources that were at the heart of Public Staff's concerns with the P1 portfolio.

B. Strategies can be pursued to minimize the risk of solar and wind additions.

Q. DO YOU THINK THE SP-AGO PORTFOLIO IS REASONABLE FROM AN EXECUTION RISK PERSPECTIVE?

A. Yes. While all the portfolios presented to the Commission have execution risks I believe the SP-AGO portfolio provides an appropriate balance of these for several reasons:

1) By aiming for a 2030 compliance date, SP-AGO preserves the option to delay if there are unforeseen challenges,

2) SP-AGO significantly minimizes the risk of securing firm pipeline capacity in comparison to the P1-P4, SP5 and SP6 portfolios.

3) While solar and wind nameplate additions may appear relatively high, the execution risk of this can be minimized through proactive transmission planning, as well as some of the strategies identified above in Section IV-A, namely:

- Pursue additional solar plus storage configurations, including those with higher capacity factors than what has been modeled to date, which can reduce needed interconnection space.
- Pursue additional wind options including imports with non-firm transmission.
- Increase opportunities for distributed resources.
- Site facilities at or near retiring coal plants to minimize transmission constraints.
- Invest in grid-enhancing technologies to increase interconnection limits.
- Identify low-cost, incremental transmission improvements following larger upgrades that can unlock greater interconnection potential.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

THE NORTH CAROLINA ATTORNEY GENERAL'S OFFICE
TESTIMONY SUMMARY OF EDWARD BURGESS
DOCKET NO. E-100, SUB 179A

The purpose of my testimony is to explain the findings of my investigation of Duke Energy's proposed Carbon Plan, which were first outlined in the Strategen Report that was included as part of AGO's July 15th Comments. My testimony affirms and builds upon many aspects of that report, and also presents new analysis conducted by Strategen through the EnCompass model to develop the SP-AGO portfolio. The key conclusions and recommendations of my testimony can be summarized as follows:

1. The passage of the Inflation Reduction Act ("IRA") is a significant and material change to key planning assumptions which are likely to affect the results of any Carbon Plan portfolio analysis, as well as certain near-term actions. While near-term procurement of solar, wind, and battery storage will be further cemented as "no regrets" options, the reasonableness of procuring new gas resources (especially CC additions) should be re-evaluated in the context of the IRA. This re-evaluation needs to be performed prior to consideration of an application for a Certificate of Public Convenience and Necessity ("CPCN") to construct such facilities.
2. Duke's Initial Portfolio modeling (i.e., P1-P4) included several significant limitations including:
    a. Arbitrary and unreasonable modeling constraints on potential resource options, including annual limits on solar additions, limited configurations of solar plus storage, limits on the flexibility of solar plus storage discharge, annual limits on onshore wind, and limited configurations of natural gas generation (detailed in Section IV-A of my direct testimony);
    b. Several "out-of-model" adjustment steps performed outside of the EnCompass optimization routine, including changes to coal retirements dates, and replacement of battery storage with gas CTs; and

c. Unreasonable assumptions for new natural gas including long plant book life, availability and cost of firm transport, and feasibility of future hydrogen conversion.

Some, but not all, of these limitations were addressed in the Supplemental Portfolios (i.e., SP5 and SP6).

3. While recognizing that analysis of the IRA is still needed, the Commission should consider the "SP-AGO" portfolio as an interim measure that advances the actions needed to meet the 2030 target and work towards net zero carbon by 2050. SP-AGO further develops the SP5 portfolio by addressing some of the other key concerns raised by several parties in this case beyond Public Staff. Some of the key features of the SP-AGO portfolio include the following:
   - Continues to pursue solar, onshore wind, and battery storage as "no regrets" near-term additions.
   - Includes an ambitious—but achievable—level of near-term solar deployment.
   - Avoids a "rush to judgment" on the need for new gas units in light of uncertainties around fuel supply and competitiveness under the IRA.
   - Maximizes benefits to ratepayers by allowing selection of valuable resource options that were excluded from Duke's analysis (e.g., 100% gas conversion at Belews Creek, alternative solar plus storage configurations, alternative wind import options).
   - Gives the Commission the flexibility to meet House Bill 951 ("HB951") compliance if there are unforeseen delays (i.e., 2030 set as initial deadline, with option to postpone at a later date).
4. At a minimum, the Commission should approve the "no regrets" procurement of solar, onshore wind, and battery resources as proposed in Duke's near-term action plan, recognizing that more analysis is needed in light of the IRA. In this sense, Duke's proposal should be viewed as a floor and it is reasonable to select greater amounts as reflected in SP-AGO.
5. Given the uncertainty regarding the availability of additional firm natural gas transportation and the natural gas prices, the Commission should defer approval of new natural gas additions (especially CC additions). Portfolio SP-AGO showed that

these additions can be delayed or avoided while still achieving the carbon reduction goals of HB951 and maintaining reliability. Further, an updated portfolio should be developed that includes the changes reflecting the IRA and other stakeholder concerns. The Commission should require Duke to include the resulting updated portfolio as supporting analysis in any CPCN applications for near-term resource additions.

6. The Commission should allow Duke to pursue the development of long-lead time resources but should apply additional caution to Small Modular Reactors. However, a determination about related cost recovery should not be made in this proceeding.
7. Given the uncertainty surrounding natural gas prices, the Commission should require Duke to develop additional contingency plan scenarios that meet HB951's requirements under a high natural gas price forecast.
8. The Commission should direct Duke to include high capacity factor solar plus storage resources in its near-term solicitations as a means to more efficiently use limited transmission interconnection space.
9. Duke's limit on annual solar additions does not appear to be supported by any quantitative analysis and does not reflect actions to increase the rate of interconnection such as the red zone transmission projects, process improvements, or grid enhancing technologies.
10. The Commission should direct Duke to conduct a near-term solicitation for onshore wind to test market readiness with a target in-service date in the 2026-2027 timeframe. This solicitation should allow for wind imports with non-firm transmission. Onshore wind is a mature, zero carbon emitting resource that has been widely deployed elsewhere in the United States.
11. Both the wind and solar procurements mentioned should seek to maximize competition through near term bid solicitations and – to the maximum extent allowed by HB 951 – through third party providers.
12. The Commission should direct Duke to pursue deployment of battery storage at the Marshall and Mayo plants as a means to achieve more economic early retirement dates in the 2027-2028 timeframe, while avoiding the need for additional transmission upgrades. These deployments should seek to leverage new DOE

financing options under the IRA. These coal-fired generators are a major contributor to Duke's annual carbon emissions; therefore, accelerating their retirements would help achieve HB951's carbon reduction goals.

13. The Commission should require Duke to employ strategies that minimize execution risk of renewable resources including:
    - Pursuing additional solar plus storage configurations with higher capacity factors that can reduce needed interconnection space.
    - Pursuing additional wind options including imports with non-firm transmission.
    - Increasing opportunities for distributed resources.
    - Siting facilities at or near retiring coal plants to minimize transmission constraints.
    - Investing in grid-enhancing technologies to increase interconnection limits.
    - Identifying low-cost, incremental transmission improvements following larger upgrades that can unlock greater interconnection potential.
14. Duke did not allow the EnCompass model to select conversion of Belews Creek to operate on 100% natural gas. Conversion of Belews Creek to 100% natural gas may allow Duke to postpone or eliminate the costly addition of new natural gas generating units.
15. In future Carbon Plan filings, the Commission should order Duke to:
    - Minimize the number of out-of-model adjustments and to provide full transparency on specific resource additions made through any out-of-model adjustments and the reason for those adjustments (e.g., reliability-based adjustments);
    - Minimize the number of resource-specific model constraints;
    - Include the Belews Creek 100% gas conversion option for the model to select;
    - Include Energy Efficiency ("EE")/Demand-Side Management ("DSM") and distributed solar as selectable resources;
    - Evaluate the costs and benefits of different levels of EE/DSM and rooftop solar deployment by varying the level of incentives provided;
    - Ensure that the forecast is not overly inflated by revising the method for including Utility Energy Efficiency ("UEE") roll-off in its load forecast relative to "naturally occurring" efficiency.

16. In a future proceeding, the Commission should re-evaluate the current cost-benefit analysis for EE/DSM (*i.e.*, the Utility Cost Test) to reflect currently proposed carbon-free resources (*e.g.*, Small Modular Reactors ["SMRs"], Offshore Wind ["OSW"]) as the alternative to the traditionally used proxy resources (*e.g.*, Combustion Turbines ["CTs"]).
17. The Commission should reject Duke's proposal to move to an "as-found" EE/DSM baseline (with possible limited exceptions) and instead maintain the current approach to counting EE savings.

This concludes my summary.

MR. MOORE: And I would move that the exhibits to Mr. Burgess' testimony as well as his report be marked for identification as prefiled.

CHAIR MITCHELL: Let's see. All right. Mr. Moore, by his report, are you referring to the analysis of the Duke Energy 2022 Carbon Plan --

MR. MOORE: Yes, Chair Mitchell.

CHAIR MITCHELL: -- filed in the docket on July 15, 2022?

MR. MOORE: Yes.

CHAIR MITCHELL: All right. Motion is allowed.

(AGO Burgess Testimony Exhibit 1, Corrected AGO Burgess Testimony Exhibit 2, AGO Burgess Testimony Exhibits 3 through 5, and AGO's "Analysis of Duke Energy 2022 Carbon Plan" were identified as they were marked when prefiled.)

MR. MOORE: Chair Mitchell, Mr. Burgess is available for cross examination.

CHAIR MITCHELL: Okay. Let's see, we've got CIGFUR.

MS. CRESS: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MS. CRESS:

Q. Mr. Burgess, good afternoon. Christina Cress for CIGFUR.

One of your recommendations to the Commission is that the Commission should continue to develop and monitor reliability metrics as part of its future Carbon Plan implementation; is that correct?

A. Yes, that's my recollection.

Q. And are you aware that CIGFUR has recommended certain such reliability metrics be developed and used as the Carbon Plan is implemented?

A. I'm not aware of what those metrics are that CIGFUR's recommended.

Q. Okay. You testified that any resource technology carries risk, correct?

A. That's correct. Each -- each type of generation resource has different characteristics that present risks in terms of system operations.

Q. And with respect to the 2030 potential interim compliance date, you also testified that that date creates significant potential execution risk due to the shorter timeline for developing new resources, including unprecedented amounts of solar; is that accurate?

A. Yeah. I would say all of the portfolios have execution risks in each type of generation technology being that it has execution risks. So, you know, I think that I wouldn't say that the 2030 date, in particular, makes it, you know, that much riskier, but it does present an additional risk, yeah.

Q. Okay. Can you please turn to page 97 of your testimony?

A. 97?

Q. That's correct. So the excerpt that I was just repeating to you verbatim was in the context of discussing a potential 2030 interim compliance date, correct?

A. Which line are you referring to?

Q. So it's page 97, and if you'll give me a second, I'll be happy to put that up for you if you can't find it on the page.

MR. MOORE: I believe it's lines 1 and 2.

THE WITNESS: (Witness peruses document.)

Okay.

Q. So that's a yes, then, to my question?

A. Could you repeat the question?

Q. Sure. So the portion of your testimony that

I just repeated to you in my prior two questions pertaining to the 2030 interim compliance date and the excerpt of your testimony regarding the increased risk of the 2030 compliance date, can you please confirm that that testimony was pertaining to the 2030 compliance date?

A. Yes. I mean, a shorter compliance deadline has additional execution risks. I agree with that.

Q. Thank you. No further questions.

CHAIR MITCHELL: All right. CPSA?

MR. SNOWDEN: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MR. SNOWDEN:

Q. Good afternoon, Mr. Burgess. Ben Snowden for CPSA.

Mr. Burgess, do you have Duke's Modeling Panel rebuttal testimony handy?

A. I do not.

Q. Okay. All right. Would you agree that, in Duke's Modeling Panel rebuttal testimony, they characterize the AGO as supporting the Companies' proposed near-term actions with respect to the procurement of solar resources?

A. Yes. I believe we characterize that as, sort of, the bare minimum or the floor of what, you know, could be done in the short term. And, you know, I think there was -- let me say this. We had, sort of, a couple of different levels to our recommendations of what should be procured in the near term, right? I mean, I think our top-line information was we should go and take a look at the IRA and, you know, whatever that result shows is really the best option overall.

Short of that, you know, we also provided some analysis with the SP AGO portfolio, which had a certain amount of solar and storage, et cetera, that could be procured in the near term. But we also said, you know, at a bare minimum, you know, what Duke has proposed, you know, should be the floor. And given that, you know, we have a short amount of time to make a decision in this proceeding, you know, let's get going on that and then, you know, consider the others as incremental to that.

Q. Thank you. To be clear, what you're testifying is that this 3,100 megawatts of near-term procurement recommended by Duke is the bare minimum that they should be doing; and you further testify that, in light of the IRA, that is likely to be an underestimate of how much Duke should be procuring in the near term; is that fair?

A. That's correct, yeah.

Q. All right. And so where Duke says in its testimony that the AGO supports its 3,100-megawatt near-term procurement amount, it is -- would you agree that that is somewhat misleading?

A. I think it's misleading in the sense that, you know, we could go above that. In fact, you know, our model portfolio showed significantly more than 3,100 megawatts of solar should be added in the optimal situation. And that's not even including the IRA assumption. So if you model that with the IRA assumptions, I think you'd see quite a bit more than the 3,100-megawatt, yeah.

Q. Thank you so much. Those are all the questions I have.

CHAIR MITCHELL: All right. EJCAN.

MR. BLUMENTHAL: No further questions.

CHAIR MITCHELL: In an abundance of caution, anybody else have questions for the witness? Questions for the witness from Duke?

(No response.)

CHAIR MITCHELL: Okay. Redirect for the witness?

MR. MOORE: No questions.

CHAIR MITCHELL: Okay. Questions from Commissioners? Commissioner Clodfelter.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Do you have the Strategen report there in front of you, Mr. Burgess?

A. Yes, I do.

Q. Okay. I'm going to -- my question really is just to clean up an evidentiary point. And I'm gonna be asking you about some confidential information, but it's mainly just about what you have and haven't seen. I'm not gonna get into the confidential information.

Would you please turn to page 39 of your report?

A. (Witness complies.)

Q. And just -- I want to focus your attention on the paragraph that is immediately before Section B, coal retirements under high gas price forecast.

A. Yeah.

Q. You make a reference in there to some information that you reviewed in response to an AGO Discovery Request 6-2.

Have you been provided a copy of Late-Filed Confidential Exhibit Number 2 that the Company filed?

A. Is that the -- does that contain the -- the underlying study of the --

Q. The document is dated July 2021. It's titled "Dual Fuel Expansion Evaluation."

A. Okay. Yes, I think --

Q. You have had a copy of that?

A. Yeah. The response to AG 6-2 had that embedded in it, so I reviewed that attachment.

Q. That's exactly what I wanted to find out, was to be sure that what you're talking about in this paragraph in your report relates to the document that is Late-Filed Exhibit Number 2.

A. That's correct, yeah.

Q. That's all I have. Thank you.

CHAIR MITCHELL: Commissioner Hughes, questions from you? Okay.

EXAMINATION BY CHAIR MITCHELL:

Q. Without going into confidential information, can you comment on the feasibility to modify the plant based on what you've learned in the -- in this proceeding or heard from testimony given by Duke witnesses during the course of this expert witness hearing?

A. Yeah. I think that what Duke testified to, and in the public testimony was that, you know, they looked into the feasibility and found that it could be done but it was not something that they would pursue due to economics. So that was what Duke testified to. You know, I disagreed with that characterization, that it would be uneconomic necessarily to pursue. So -- and I'm happy to go into, sort of, further thoughts on that.

Q. What about gas supply? Have you studied the gas supply issue?

A. Yeah. So that's a great question. And certainly, if you were to convert, you know, coal unit to run more on gas, that there might be additional supply needs. And I think that, you know, there could be some limitations of that gas, but there's also some advantages. The fact that there is already existing gas infrastructure at some of these dual fuel units would potentially reduce the cost of that.

And Duke actually did provide some cost estimates of the gas upgrades too, and they look to be relatively affordable. So I think that, you know, when you're, sort of, looking at that versus, you know, new pipeline expansions, interstate pipeline expansions, you know, that's something that should be considered. Whether the sort of -- you could also secure the fuel supply, you know, to bring in interstate, that's, I think, another question that should be evaluated too.

And again, I think that the fact that there's some existing infrastructure there probably minimizes that risk to some degree.

Q. Okay. But did you specifically look at the question of whether Duke could get fuel into the state to fire that facility at 100 percent?

A. Yeah. I think that that would be, in some ways, a similar type of assessment to looking at a new, you know, combined cycle plant of a similar scale, similar magnitude, in terms of the gas that's needed. And again, that particular location, I don't know the -- I mean, I haven't studied or I don't know of any studies that have looked at that particular location for getting gas in there.

Q. Okay. And to the extent that you know, and you may not, and you can say so, would -- you know, I've learned during the course of this proceeding that converting a coal-fired facility to fire -- to run on gas is less efficient than simply building, you know, a gas-fired plant.

So would converting Belews 1 and 2 to run on 100 percent gas, would that require more gas than

the -- at least one or both of the CCs that we see --
A. Right.
Q. -- in Duke's portfolio -- portfolios?
A. I think it's hard to answer without looking at the full portfolio and looking also at how that plant is being dispatched in the production cost runs. So, you know -- and you have to look at it both not only from a fuel perspective but from a CAPEX perspective too.
So when you look at the totality of the CAPEX and the fuel, you may be, you know, less efficient in operations, but, you know, you're saving a lot on CAPEX too. And so putting those two together could be more affordable. Additionally, you know, it depends -- again, it depends on how much the plant operates. If it's, you know, a conversion, it actually -- and it's less sufficient, you may actually have less concern about the gas fuel, because it might not be operating as much as, say, a brand-new combined cycle unit.
And so, you know, there's all these different factors that have to be considered together. And I didn't see any analysis performed by Duke or anyone else that, sort of, looked at, you know, in the context of the Carbon Plan and the whole portfolio, how those

balance out.

Q. Okay.

A. I guess I might add one thing to that. We did -- you know, the AGO's SP -- AGO portfolio run did model the Belews Creek conversion, and so we put that in as one of the assumptions for our model run.

CHAIR MITCHELL: Okay. I don't have anything further for the witness. Just making sure no more -- go ahead.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Just because I don't remember sitting here, and you'll save me having to fight back through the material, so let me just ask.

I can't remember, when you did model that, whether you were modeling it primarily as a capacity resource or if you were modeling it for the energy output.

A. I mean, it provided both.

Q. Well, it does. But, I mean, which was -- what were -- what kind of resource were you looking at the converted plant being?

A. Yeah. I'd probably have to go back and see how it was operating in the model. I think that, you know, certainly what we see with a lot of the gas plants, and I would expect that to be the same, is that the energy output, you know, declines fairly rapidly over, you know, the, sort of, late 2020s into the 2030s. And so then it's more of a capacity resource in that case.

But, you know, in that sort of -- there's this window of time where Duke's system really appears to have a lot of energy need, and that's, sort of, in that, you know, 2027, 2028 time frame, and that's where, you know, I think it does have some value in that, sort of, period of time. And that's why I think, you know, we're seeing some of these in Duke's modeling, you know, new combined cycle units going in right around then to address some of that energy need.

CHAIR MITCHELL: Okay. All right.

We'll take questions on Commissioners' questions.

EXAMINATION BY MS. CRESS:

Q. Just one, I believe. As a follow-up to Commissioner Clodfelter's question in which he asked, and I'm paraphrasing, whether you had had a chance to review the information that the Companies filed as Late-Filed Exhibit Number 2.

I'd like to just ask, without bringing us into confidential session, whether you had occasion to evaluate if all of the files embedded in the Companies' response to AGO Data Request 6-2 were produced as part of that late-filed exhibit?

A. I haven't gone back to look at -- yeah, I can't say with certainty if they had all of them in there or not. They were -- I think, if I recall correctly, there were four files in the original discovery response, and I can't remember how many were in the late-filed exhibit.

Q. Okay. Thank you.

CHAIR MITCHELL: All right. Attorney General's Office?

MR. MOORE: No questions.

CHAIR MITCHELL: Okay. All right. With that, I will entertain a motion.

MR. MOORE: Yes, Chair Mitchell. I missed earlier that, on September 8th, a corrected Exhibit 2 to Mr. Burgess' testimony was filed. So at this time, I would move that Mr. Burgess' premarked and corrected exhibits be moved into the record, and also his report be entered into the record as well.

CHAIR MITCHELL: Hearing no objection to your motion, it will be allowed and marked confidential as appropriate.

MR. MOORE: Thank you.

(AGO Burgess Testimony Exhibit 1, Corrected AGO Burgess Testimony Exhibit 2, AGO Burgess Testimony Exhibits 3 through 5, and AGO's "Analysis of Duke Energy 2022 Carbon Plan" were admitted into evidence.)

CHAIR MITCHELL: Okay. You may step down, Mr. Burgess, and be excused. Thank you very much for your testimony today.

All right. We've got CPSA witnesses.

MR. SNOWDEN: Chair Mitchell, CIGFUR has requested that their witness go ahead of us so that he can return to Charlotte today. And CPSA has no problem with that if the Chair will permit it.

MS. CRESS: In full disclosure, I haven't had a chance to confirm that this is okay with Commission staff, so I apologize.

CHAIR MITCHELL: Just making sure that no other parties objecting to the switch. Okay. All right. You may proceed.

MS. CRESS: Thank you, Chair Mitchell. At this time, CIGFUR II and III calls witness

Bradford Muller to the stand.

CHAIR MITCHELL: Good afternoon, Mr. Muller, if you would, raise your right hand, left hand on the Bible, please, sir.

Whereupon,

BRADFORD MULLER,

having first been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION BY MS. CRESS:

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

A. Bradford D. Muller. 2109 Randolph Road, Charlotte, North Carolina 28207.

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

A. I'm the vice president of corporate communications for Charlotte Pipe and Foundry Company.

Q. And on whose behalf are you testifying today?

A. On behalf of the Carolina Industrial Group for Fair Utility Rates II and III, also known as CIGFUR. Charlotte Pipe is an industrial customer of Duke Energy Carolinas, currently taking service under DEC's OPTV rate schedule. And we're also a member company for CIGFUR III.

Q. Mr. Muller, on September 2, 2022, did you cause to be prefiled in this docket direct testimony consisting of 17 pages, one appendix, and two exhibits?

A. Yes.

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

A. No.

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

A. Yes.

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

A. That's correct.

MS. CRESS: Chair Mitchell, at this time, I would ask that CIGFUR II and III witness Muller's direct testimony consisting of 17 pages and one appendix be entered into the record as if given orally from the stand. And I would also request that Mr. Muller's witness summary, as previously filed in Docket Number E-100, Sub 179-A also be entered into the record.

CHAIR MITCHELL: All right. That motion is allowed.

(Whereupon, the prefiled direct testimony and Appendix A of Bradford Muller and prefiled summary testimony of Bradford Muller 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:		
Duke Energy Progress, LLC, and	)	**DIRECT TESTIMONY OF**
Duke Energy Carolinas, LLC, 2022 Biennial	)	**BRADFORD D. MULLER FOR**
Integrated Resource Plans and Carbon Plan	)	**CIGFUR II & III**

Q: MR. MULLER, PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A: My name is Bradford D. Muller, and my business address is 2109 Randolph Road, Charlotte, North Carolina 28207. I currently serve as the Vice President of Corporate Communications, Marketing, and Government Affairs for Charlotte Pipe and Foundry Company.

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

A: I have a Bachelor of Arts degree from Kenyon College**.** I have worked for Charlotte Pipe and Foundry Company ("Charlotte Pipe") for 20 years. During my tenure with Charlotte Pipe, I have gained direct first-hand knowledge and experience with many facets of Charlotte Pipe's business operations, including its manufacturing processes and energy procurement, usage, and load. My professional biography can be found at Appendix A to this testimony.

Q: PLEASE TELL US WHO IS SPONSORING YOUR TESTIMONY IN THIS PROCEEDING.

A: I am providing this testimony on behalf of the Carolina Industrial Group for Fair Utility Rates II & III (together, "CIGFUR"). Charlotte Pipe is an industrial customer of Duke Energy Carolinas, LLC, currently taking service under DEC's Optional Power Time of Use, Voltage Differential, Secondary Large ("OPT-V") rate schedule. Charlotte Pipe is one of CIGFUR III's member companies.

Q: CAN YOU PLEASE TELL US MORE ABOUT CHARLOTTE PIPE AND FOUNDRY COMPANY AS A BUSINESS?

A: Charlotte Pipe is a fifth-generation, family-owned manufacturer based in North Carolina. Founded in 1901, Charlotte Pipe is the leading producer of cast iron and plastic pipe and fittings for plumbing systems. As its name suggests, Charlotte Pipe is headquartered in Charlotte, North Carolina. Charlotte Pipe has seven plant locations across the United States. Our company recently acquired a wholly owned subsidiary, Neenah Enterprises, Inc., which operates three additional domestic cast iron foundries. Charlotte Pipe employs approximately 1,400 people at its facilities in North Carolina and approximately 2,700 people at its facilities across the country, including those in North Carolina.

In Monroe, North Carolina, Charlotte Pipe operates a plastic extrusion and injection molding manufacturing plant with a demand of 17 MW. In addition, Charlotte Pipe is in the process of replacing a cast iron foundry in uptown Charlotte with a demand of 58 MW with a $460 million state-of-the-art greenfield foundry in Oakboro, NC. The new 45-acre facility in Oakboro will have a 70-MW demand and will have converted from using a fossil fuel melt process in the old foundry to a cleaner, more energy-efficient electric melt technology in the new plant.

Q: CAN YOU PLEASE TELL US WHAT, IF ANY, CONCERNS YOU HAVE REGARDING DUKE ENERGY'S PROPOSED CARBON PLAN?

A: This response corresponds to Ordering Paragraphs 1.i.i. and 1.i.v. of the Commission's July 29, 2022 Order Scheduling Expert Witness Hearing, Requiring Filing of Testimony, and Establishing Discovery Guidelines ("Order").

As a company whose products require energy-intensive manufacturing processes, Charlotte Pipe is very concerned that the total costs and bill impacts to ratepayers have been significantly understated in Duke's proposed Carbon Plan. This is particularly problematic because the estimated rate impacts, albeit understated, will still push industry to the brink (or beyond) of rate increases it is able to absorb before manufacturers are forced to make difficult decisions, including potentially shifting load (and corresponding jobs) out of state where electric rates are more competitive.

More specifically, I believe Duke's proposed Carbon Plan fails to provide an "all-in" total cost and rate impact estimate encompassing all projected capital spending planned in the coming years, both related and unrelated to the Carbon Plan. This is concerning because it means the Commission is being asked to decide—without the benefit of complete and accurate cost and rate impact information—issues such as whether Duke's proposed Carbon Plan complies with least-cost principles and whether Duke's proposed Carbon Plan constitutes the "reasonable steps" to carbon emissions reductions contemplated by House Bill 951. In addition, while I believe the cost and rate impacts provided are understated, the estimates provided by Duke are still—even though understated—significantly large enough to have a detrimental impact on the North Carolina economy.

Q. CAN YOU ELABORATE ON WHAT YOU MEAN BY DUKE'S CARBON PLAN FAILS TO PROVIDE AN "ALL-IN" TOTAL COST AND IMPACTS TO RATEPAYERS FOR ALL PLANNED SPENDING BOTH RELATED AND UNRELATED TO THE CARBON PLAN?

A: This response corresponds to Ordering Paragraphs 1.a., 1.b., 1.e., 1.f., 1.g., 1.i.i., and 1.i.v. of the Commission's Order.

First, the scenarios Duke has provided with their multi-portfolio proposal are going to be costly no matter what. Again, my testimony emphasizes that this is likely an understatement, but Public Staff's Exhibit 2 – DEC Cumulative and Annual Average Bill Impacts for Industrial Customers – reflects Duke's estimated impact and average annual impact to monthly industrial bills for an average DEC industrial customer using 32,500,000 kWh with a corresponding demand of 50 MW.

TOTAL IMPACT TO MONTHLY INDUSTRIAL BILLS				
Industrial - 32,500,000 KWh / 50,000 KW				
	2023- 2030 Impact to Industrial Bills		2023 - 2035 Impact to Industrial Bills	
	% Increase	$ Increase	% Increase	$ Increase
DEC - COS - (P1)	7.5%	$123,507	30.8%	$507,228
DEC - COS - (P2)	4.9%	$80,009	27.6%	$454,268
DEC -COS - (P3)	6.1%	$100,751	26.9%	$443,057
DEC - COS - (P4)	4.8%	$79,208	25.8%	$425,275

AVERAGE ANNUAL IMPACT TO MONTHLY INDUSTRIAL BILLS				
Industrial - 32,500,000 KWh / 50,000 KW				
	2023- 2030 Impact to Industrial Bills		2023 - 2035 Impact to Industrial Bills	
	% Increase	$ Increase	% Increase	$ Increase
DEC - COS - (P1)	1.0%	$17,643.88	2.3%	$42,269.02
DEC - COS - (P2)	0.7%	$11,429.83	2.0%	$37,855.69
DEC -COS - (P3)	0.9%	$14,392.93	2.0%	$36,921.44
DEC - COS - (P4)	0.7%	$11,315.37	1.9%	$35,439.58

These impacts—again, understated though they very likely are—will be even more significant for DEP's industrial customers. And the alternative portfolios proposed by Duke would result in approximately double the total bill impact for each alternative portfolio for both DEP and DEC's industrial customers.

TOTAL IMPACT TO MONTHLY INDUSTRIAL BILLS				
Industrial - 32,500,000 KWh / 50,000 KW				
	2023- 2030 Impact to Industrial Bills		2023 - 2035 Impact to Industrial Bills	
	% Increase	$ Increase	% Increase	$ Increase
DEP - COS - (P1)	30.1%	$631,878	38.6%	$807,826
DEP - COS - (P2)	24.6%	$517,343	38.5%	$804,933
DEP - COS - (P3)	15.7%	$333,761	26.2%	$551,442
DEP - COS - (P4)	14.8%	$314,976	29.0%	$609,823

AVERAGE ANNUAL IMPACT TO MONTHLY INDUSTRIAL BILLS				
Industrial - 32,500,000 KWh / 50,000 KW				
	2023- 2030 Impact to Industrial Bills		2023 - 2035 Impact to Industrial Bills	
	% Increase	$ Increase	% Increase	$ Increase
DEP - COS - (P1)	3.9%	$90,268.35	2.8%	$67,318.86
DEP - COS - (P2)	3.2%	$73,906.18	2.8%	$67,077.76
DEP - COS - (P3)	2.2%	$47,680.15	2.0%	$45,953.48
DEP - COS - (P4)	2.0%	$44,996.54	2.2%	$50,818.56

Second, these projected cost and rate impacts are understated, in part, because they do not reflect certain costs that Duke contends are either unrelated to the Carbon Plan or will be common to all proposed portfolios. For example, Duke did not include costs or rate impacts associated with Grid Improvement Plan ("GIP") investments. But GIP costs are still cost drivers that affect the total cumulative rate impact. Without the critically important context of total cumulative rate impact for all new capital spending, it is impossible to evaluate whether the Carbon Plan as proposed is least-cost or whether it constitutes "reasonable steps" towards the energy transition. In addition, Duke makes it clear that for all portfolios, the 2050 long-term strategy for new and existing natural gas plants is to retrofit them so that they can accommodate hydrogen as a fuel source. However, Duke did not include cost assumptions for these hydrogen-enabling infrastructure upgrades into its Carbon Plan total cost projections or bill impact estimates. In addition, Duke did not include other costs common to all portfolios, like storm securitization and the Red Zone Transmission Expansion Plan transmission and distribution upgrades to accommodate additional renewable generation. Finally, while we support Duke's pursuit of subsequent license renewals ("SLRs") for its nuclear fleet, Duke did not include the projected costs for obtaining these SLRs. These costs need to be reflected in Duke's Carbon Plan cost estimates and projected rate impacts because they are an incremental cost to the present value of revenue requirement ("PVRR") of each Carbon Plan portfolio. These are just a few examples of cost drivers that were largely or entirely omitted from cost and rate impact estimates in Duke's proposed Carbon Plan.

Third, we note that Duke did not provide estimates for the potential additional costs to its North Carolina customers in the event that the Public Service Commission of South Carolina ("PSCSC") rejects the Carbon Plan or otherwise disallows cost recovery of costs to comply with House Bill 951. While CIGFUR contends Duke's North Carolina customers should be held harmless for the South Carolina jurisdictional allocable portion of Carbon Plan implementation and compliance costs, CIGFUR also believes that some modification of the Carbon Plan—at least in the near-term until 2024, when the next Carbon Plan biennial review will occur—is warranted as a hedge against the substantial regulatory risk of the PSCSC's rejection of the Carbon Plan. I believe this is necessary to protect Duke's North Carolina customers from the possibility that Duke seeks future cost recovery from its North Carolina customers for the South Carolina jurisdictional allocable portion of such costs.

I believe the Commission and the general public need to be provided with revised Carbon Plan cost estimates and rate impacts that paint a more all-encompassing and accurate picture of what the "all-in" cost and bill impact forecasts expected to be shouldered by North Carolina ratepayers through 2035 will be, for spending both related and unrelated to the Carbon Plan. Without this critically important information, how can the Commission be expected to decide whether Duke's proposed Carbon Plan complies with the requirements of HB 951 that it be both least-cost and constitutes "reasonable steps" towards compliance with the carbon dioxide emissions reduction goals set forth in that legislation?

Finally, I believe Duke needs to affirmatively assure this Commission and its ratepayers of its intent to securitize—for the benefit of ratepayers—50% of the costs associated with the early, uneconomic retirement of its still serviceable coal fleet, which will come at a substantial cost to ratepayers and is another cost driver that Duke did not sufficiently quantify or otherwise account for in its cost estimates and projected rate impacts in its proposed Carbon Plan.

Q: CAN YOU ELABORATE ON THE POSITION THAT DUKE'S NORTH CAROLINA RATEPAYERS SHOULD BE HELD HARMLESS FOR SOUTH CAROLINA'S JURISDICTIONAL ALLOCABLE SHARE OF HB 951 COMPLIANCE COSTS IN THE EVENT SOUTH CAROLINA REJECTS DUKE'S CARBON PLAN?

A: This response corresponds to Ordering Paragraphs 1.a., 1.g., 1.i.i., and 1.i.v. of the Commission's Order.

Duke failed to model how the Carbon Plan portfolios should potentially be adjusted—and how the resulting rate impacts to its North Carolina customers would be affected—in the event that the PSCSC rejects Duke's proposed Carbon Plan next year when Duke seeks regulatory approval through its South Carolina IRP docket. Should South Carolina reject Duke's Carbon Plan, will the utility attempt to unfairly layer even more costs on North Carolina ratepayers? I believe this would be an unreasonable and unjust course of action that would run afoul of the

Legislature's understanding that Carbon Plan implementation costs would be spread across Duke's dual-state footprint in the Carolinas, not shouldered exclusively by North Carolina ratepayers. Most concerning, this issue remains unaddressed. Duke has touted its proposed Carbon Plan as the "Carolinas Carbon Plan." If it is potentially going to instead be the North Carolina—emphasis on the singular "Carolina"—Carbon Plan, then Duke's portfolios should be scaled back and adjusted as appropriate. In no universe is it appropriate or acceptable for North Carolina ratepayers to foot any portion of the bill for South Carolina's jurisdictional allocable share of Carbon Plan implementation costs.

Q: CAN YOU SPEAK TO THE IMPORTANCE OF RELIABILITY AND POWER QUALITY TO CIGFUR MEMBER COMPANIES GENERALLY AND TO CHARLOTTE PIPE SPECIFICALLY, AS ONE OF DEC'S LARGE INDUSTRIAL CUSTOMERS?

A: This response corresponds to Ordering Paragraphs 1.a. and 1.j. of the Commission's Order.

Duke should be applauded for presently being a low-cost, high-quality electricity supplier. Charlotte Pipe operates seven plants around the United States. Duke Energy currently offers the most reliable, highest quality and least cost electricity compared with our suppliers in other states where we operate. But we worry this has the potential to change for the worse as the Carbon Plan is implemented.

As an energy-intensive manufacturer, power interruptions—even momentary flickers—can take an enormous and costly toll on our manufacturing equipment, processes, and production output. A power quality event is typically measured by the percent of the nominal voltage in conjunction with the duration of the event, which is measured in milliseconds. The deeper the sag, the less time it takes to negatively impact the equipment. A shallower sag can negatively impact operations given a long enough duration.

Charlotte Pipe's plastic extrusion systems are the most sensitive to power quality incidents. A simple voltage sag (voltage drop from nominal) can disrupt the extrusion line operation, shut machines down or otherwise damage equipment, or cause electrical fires, among other consequences. Typically, sags wherein the voltage is 70% of nominal and greater than 30 milliseconds (less than two cycles) in duration will negatively impact a significant number of extrusion lines. Any total loss of power regardless of duration will take out the entire plant. For these reasons, any disruption or interruption in electric service to the extrusion lines, however brief, poses a safety risk to our employees, disrupts our operations, decreases our production output, and increases our costs.

For example, after our most recent power failure at our Monroe, NC facility, which was caused by a weather event, it took two days to get one plant back online due to burnt dies on the extrusion lines and four days to get a second plant up and running due to that plant being single-phase. The single-phase event caused multiple drive and motor failures, along with almost all our dies needing to be cleaned and refurbished. Attached to this testimony as Exhibit 1 are photos showing partially burnt dies. Attached to this testimony as Exhibit 2 is a photo showing the amount of scrap product resulting from a power failure incident at one of our plants in Texas.

As an energy-intensive industrial user, we are not unique in our need for high-quality, reliable power. Indeed, this is a high priority for all CIGFUR member companies. Though we appreciate Duke's commitment to NERC standards for reliability, it is concerning to hear how "high penetration of wind and solar have exposed energy shortfalls for both brief and prolonged periods of time due to significant weather-related output fluctuations."[1] The challenges of managing a complex system as large as Duke's with increasing amounts of increasingly variable resources being added to the system underscore how important maintaining or improving—as required by HB 951—system reliability, including power quality, will continue to be in the future as the Carbon Plan is implemented over time.

For these reasons, I believe Duke should have explicitly analyzed power quality as a distinct metric under the reliability umbrella in its proposed Carbon Plan. Even though power quality may very well be analyzed locally,[2] Duke should at least be required in future iterations of the Carbon Plan to consider and analyze granular circuit-specific data in the aggregate regarding power quality incidents. CIGFUR believes that just like the baseline and accounting methodology for quantifying compliance with the carbon emissions reduction goals set forth in HB 951, so too should there be specific reliability and power quality metrics—beyond just SAIDI and SAIFI—for ensuring compliance with those corresponding requirements set out in HB 951. For example, Duke should be required to also track MAIFI (Momentary Average Interruption Frequency Index) = Total # of

[1] Direct Testimony of Duke Witnesses Roberts and Holeman, at 26.

[2] *See id.* at 83.

momentary customer interruptions per year / total number of customers. Beyond MAIFI, Duke could also track aggregated data pertaining to conditions like changes in voltage, including transient change, sags, surges, undervoltage conditions, harmonic distortions, noise, stability, flickers, and frequency deviations.

Q: SHOULD THE COMMISSION LOOK TO OTHER STATES AND CONSIDER HOW DECARBONIZATION EFFORTS ARE BEING IMPLEMENTED ELSEWHERE AS IT DEVELOPS THE INITIAL CARBON PLAN?

A: This response corresponds to Ordering Paragraphs 1.c.ii., 1.c.iii., 1.d., 1.i.i., 1.i.iii., and 1.j. of the Commission's Order.

Yes, the North Carolina Utilities Commission should follow the example of the Virginia State Corporation Commission ("SCC"), the agency responsible for regulating Virginia's public utilities, including Dominion Energy Virginia ("Dominion"). Dominion recently proposed a 2.6 GW offshore wind and transmission project projected to cost $9.8 billion initially and $21.5 billion total over the 30-year life of the asset. While the SCC granted Dominion the right to own, build, and operate the proposed project without competitive procurement, it also imposed several conditions for the protection of ratepayers. These conditions included a performance guarantee which would hold Dominion's customers harmless for any shortfall in energy production below the estimated 42% annual net capacity factor, measured on a three-year rolling average. In addition, the SCC imposed reporting requirements for cost overruns. I believe this Commission should consider imposing similar conditions for all resources selected in the Carbon Plan, but particularly for long-lead time resources and any and all other resources for which the Commission does not approve competitive or other third-party procurement as a means of ensuring compliance with least-cost principles.

Q: HOW WILL IMPLEMENTATION OF THE CARBON PLAN AND THE RELATED RISING PRICES FOR ENERGY AFFECT BUSINESSES CONSIDERING WHETHER TO EXPAND OR LOCATE FACILITIES IN NORTH CAROLINA?

A: This response corresponds to Ordering Paragraphs 1.a., 1.a.iii., 1.i.i., and 1.j. of the Commission's Order.

Because our plants are highly energy-intensive, whenever Charlotte Pipe has sited new plant locations throughout our 120-year history, electricity prices and the availability of high-quality, reliable power are primary drivers of the decision regarding where to expand or potentially site a new facility. If Charlotte Pipe was to lose the advantage of Duke's historically low-cost, reliable, high-quality power, this would likely preclude us from expanding operations and creating jobs in the DEC or DEP service territories. Many other CIGFUR member companies would likely fall in this same category, if Duke's future electric service is no longer affordable, reliable, and high-quality.

If the Carbon Plan results in exorbitant increases in electricity prices, decreased power quality, or decreased reliability, existing industry will likely begin to leave the State, and new industry will likely choose not to locate new facilities or expand existing facilities here. The increasing cost structure will then have to be spread over a dwindling industrial rate base, making North Carolina even less competitive and less inclined to attract new manufacturing, launching a death spiral of economy-killing deindustrialization. Nowhere in Duke's plan is this very predictable scenario addressed. Instead, Duke's economic impact analysis is almost exclusively focused on how it will attract new economic development projects through the "Clean-Energy Economy" without addressing its plan to ensure it actually retains existing non-residential customers and the good jobs those non-residential customers provide to citizens and residents of this State.

Q: WHAT IS YOUR OPINION REGARDING DUKE'S PLAN TO PURSUE SUBSEQUENT LICENSE RENEWALS FOR ITS EXISTING NUCLEAR FLEET?

A: This response corresponds to Ordering Paragraphs 1.e., 1.i., 1.i.i., and 1.i.v. of the Commission's Order.

Charlotte Pipe strongly supports Duke Energy's efforts to relicense its existing nuclear fleet, which will be necessary to serve base load and without which a Carbon Plan would be impossible to implement from a reliability, cost, and executability perspective. Nuclear is a net-zero energy source and the only proven technology capable of generating electricity that is at once dispatchable, reliable, emissions-free, low-cost, and capable of scaling up to meet growing demand. That said, we believe Duke should be required to report to the Commission, on at least an annual basis, regarding Duke's relicensing efforts and the expected time frame for obtaining such SLRs as well as updated cost estimates as more information is gathered over time. In addition, Duke should be required—in its 2024 biennial Carbon Plan proceeding and thereafter—to explicitly include such costs—and all other "common across all portfolios" costs—in its projected Carbon Plan cost estimates and associated rate impacts.

Q: WHAT IS YOUR OPINION REGARDING A CARBON PLAN THAT PROVIDES FOR NEW NATURAL GAS GENERATING PLANTS TO BE BUILT?

A: This response corresponds to Ordering Paragraphs 1.c. and 1.j. of the Commission's Order.

Renewable energy resources are variable resources, and the grid cannot operate without sufficient reliable, dispatchable back-up power. Charlotte Pipe and many other CIGFUR member companies support natural gas and believe it will play a critical role as a bridge fuel to facilitate the energy transition in a way that does not compromise existing reliability. In the event new natural gas is selected as a Carbon Plan resource, however, the same cost mitigation tools I previously recommended should likewise apply to any new natural gas plants. In addition, Duke should be required to evaluate whether retrofitting existing coal plants to burn natural gas—particularly given the transmission infrastructure already in place in those locations—could be a possible least-cost alternative compared to building a new natural gas plant.

Q: DO YOU HAVE ANY OTHER FEEDBACK TO SHARE ON THE PROPOSED CARBON PLAN AT THIS TIME?

A: This response corresponds to Ordering Paragraphs 1.b., 1.d., 1.i.i., and 1.i.iii. of the Commission's Order.

In fairness, I believe that the Carbon Plan proposed by Duke Energy represents an earnest effort by Duke, particularly given the short time frame within which Duke had to conduct modeling and file its proposal with the Commission. We appreciate that Duke flagged certain unknown variables as well as the numerous other unknowns flagged by the Public Staff, CIGFUR, and various other intervenors, as these are extremely complex technical and economic issues that require more rigorous study. For the sake of all ratepayers, we believe the Commission should not race to put their stamp on a particular portfolio. Rather, Duke, the Commission, and intervenors should be given adequate time–another two years at a minimum–to obtain and evaluate substantial additional information to enable the Commission to decide the “least cost, most reliable” approach. Along these same lines, CIGFUR believes that in the instant proceeding the Commission need only approve near-term activities to occur between now and the first Carbon Plan biennial review process in 2024. Because there are so many unknown variables that could have a material impact on policy objectives like reliability, costs, ratepayer impacts, and executability, I encourage the Commission to remain flexible and open to multiple portfolios at this time.

Moreover, CIGFUR encourages the Commission to utilize the general and specific discretion it was delegated through the passage of HB 951, especially pertaining to the time frame for compliance with the carbon emissions reduction goals set forth in the legislation. Compliance in years later than 2030 allows for costs to be spread out over a longer period of time, thus helping to make the year-over-year rate impacts for ratepayers more manageable and ensuring that the least-cost plan is selected. In addition, it enables North Carolina to be flexible and in a position to adapt to new information or technology advancements or any number of other changed circumstances that could warrant altering the path forward in the future. For these reasons, CIGFUR supports the “check and adjust” strategy recommended by Duke Energy. Finally, I note that all portfolios follow a similar trajectory to achieve net-zero emissions by 2050. For these reasons, the Commission should not feel pressured to abide an aspirational interim compliance goal of 2030.

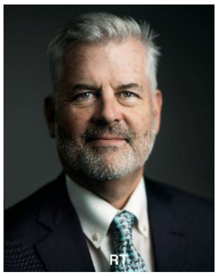
Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes, it does.

CHARLOTTE
PIPE AND FOUNDRY COMPANY

BRADFORD D. MULLER

Vice President, Corporate Communications
Charlotte Pipe and Foundry Company



Brad is a marketing and communications strategist with more than thirty years of experience in public and corporate affairs, international and government relations, manufacturing and business marketing, crisis management and media training, and more.

Brad spent nearly a decade in Washington, DC, including stints with the U.S. State Department and Edelman Worldwide, the largest public relations and public affairs agency in the world.

Currently, Brad leads government affairs, marketing and corporate communications for Charlotte Pipe and Foundry Company, a fifth-generation, family-owned manufacturer based in North Carolina. Founded in 1901, Charlotte Pipe and Foundry is the leading U.S. producer of cast iron and plastic pipe and fittings for plumbing systems.

Brad worked for the U.S. State Department's Agency for International Development (A.I.D.) in the George H.W. Bush Administration as a desk officer, managing foreign aid programs for Afghanistan and later for Bulgaria and Albania after the 1989 fall of the Berlin Wall.

At Edelman, Brad worked for the late Michael Deaver, former Deputy Chief of Staff to President Ronald Reagan, on a variety of public affairs and international relations issues, including the passage of the North American Free Trade Act (NAFTA).

Brad is very active within the metalcasting industry and his local community, including:

- Leadership roles over the last decade with the American Foundry Society, including incoming president of AFS in 2023, the Cast Iron Soil Pipe Institute and the Municipal Casting Association.
- Providing written and verbal testimony as an industry representative and subject matter expert on manufacturing and regulatory matters before two U.S. House of Representatives subcommittees and the Small Business Administration.
- Advisor to the U.S. Department of Commerce Industry Trade Advisory Committee on Steel and Iron (ITAC) since 2014.
- Member of the U.S. Chamber of Commerce Labor Relations Committee since 2008.
- Served on boards of the YMCA of Greater Charlotte, the Charlotte Chamber of Commerce, the North Carolina Chamber, the John Locke Foundation, and the Charlotte Mecklenburg Police Foundation (former board chair).

PROFESSIONAL EXPERIENCE

CHARLOTTE PIPE AND FOUNDRY COMPANY – CHARLOTTE, NC

Vice President of Corporate Communications, 2002 – Present

- Senior management with fiduciary responsibility as an Officer of the company
- Corporate spokesperson and media contact
- Active role in various industry trade associations
- Leads the company's Government Affairs practice
- Responsible for marketing and branding strategic planning and execution

PRICE / MCNABB – CHARLOTTE, NC

Senior Account Executive, 1995 – 2002

- Managed corporate branding, advertising and public relations programs for numerous clients, including Square D Company and its French parent, Schneider Electric.

EDELMAN WORLDWIDE – WASHINGTON, D.C.

Account Supervisor, 1993 - 1995

- Developed and executed strategic communications, media relations and public affairs programs for a variety of clients, including the Portuguese Trade Commission; the Embassy of India; the city of St. Petersburg, Russia; and Bank of Boston's Global Initiative.

U.S. STATE DEPARTMENT, AGENCY FOR INTERNATIONAL DEVELOPMENT – WASHINGTON, D.C.

A.I.D. Desk Officer and Special Assistant, 1989 - 1993

Special Assistant to the Assistant Administrator for Europe, April 1991 – January 1992

- Responsible for a range of operational, advisory, and supervisory activities for the Assistant Administrator for the Bureau for Europe. Supervised Executive Secretariat operations and personnel.

Desk Officer, Bureau for Europe, March 1990 – April 1991 / January 1992 – February 1993

- Directed and supervised $90 million assistance program for Albania, a $34 million aid package for Bulgaria and an annual $20 million U.S. contribution to the International Fund for Ireland.

- Primary liaison for communicating A.I.D. policy and program details to U.S. Embassy staff overseas and host country officials in Washington. Traveled extensively overseas to supervise aid programs in-country.

Temporary A.I.D. Representative to Albania, January 1992

- Monitored economic and humanitarian assistance in-country for the U.S. Ambassador, including delivery and distribution of critical U.S. food shipments via Greece.

Project Officer, Afghanistan Task Force, May 1989 – March 1990

- Working in Washington and in Pakistan, collected and analyzed data concerning UN and other donor activities related to refugee assistance programs.

PRESIDENTIAL TRANSITION TEAM / WHITE HOUSE STAFF – WASHINGTON, D.C.

- Office of Presidential Personnel, November 1988 – May 1989

BUSH / QUAYLE '88 PRESIDENTIAL CAMPAIGN – WASHINGTON, D.C.

- Scheduling Office, July – November, 1988

EDUCATION

KENYON COLLEGE, Gambier, Ohio Bachelor of Arts, Political Science, 1988

Summary of Direct Testimony of Bradford D. Muller
On behalf of Carolina Industrial Group for Fair Utility Rates II and III
Docket No. E-100, Sub 179

My name is Bradford D. Muller and I serve as the Vice President of Corporate Communications, Marketing, and Government Affairs for Charlotte Pipe and Foundry Company. During my 20-year tenure with Charlotte Pipe, I have gained direct first-hand knowledge and experience with many sides of Charlotte Pipe's business operations, including its manufacturing processes and energy procurement, usage, and load.

I am providing this testimony on behalf of the Carolina Industrial Group for Fair Utility Rates II & III (together, "CIGFUR"). Charlotte Pipe is an industrial customer of Duke Energy Carolinas, LLC, currently taking service under DEC's Optional Power Time of Use, Voltage Differential, Secondary Large ("OPT-V") rate schedule. Charlotte Pipe is one of CIGFUR III's member companies.

Charlotte Pipe is a fifth-generation, family-owned manufacturer based in North Carolina. Founded in 1901, Charlotte Pipe is the leading producer of cast iron and plastic pipe and fittings for plumbing systems. As its name suggests, Charlotte Pipe is headquartered in Charlotte, North Carolina. Charlotte Pipe has seven plant locations across the United States. Our company recently acquired a wholly owned subsidiary, Neenah Enterprises, Inc., which operates three additional domestic cast iron foundries. Charlotte Pipe employs approximately 1,400 people at its facilities in North Carolina and approximately 2,700 people at its facilities across the country, including those in North Carolina. In Monroe, North Carolina, Charlotte Pipe operates a plastic extrusion and injection molding manufacturing plant with a demand of 17 MW. In addition, Charlotte Pipe is in the process of replacing a cast iron foundry in uptown Charlotte with a demand of 58 MW with a $460 million state-of-the-art greenfield foundry in Oakboro, NC. The new 45-acre facility in Oakboro will have a 70-MW demand and will have converted from using a fossil fuel melt process in the old foundry to a cleaner, more energy-efficient electric melt technology in the new plant.

As a company whose products require energy-intensive manufacturing processes, Charlotte Pipe is very concerned that the total costs and bill impacts to ratepayers have been significantly understated in Duke's proposed Carbon Plan. This is particularly problematic because the estimated rate impacts, albeit understated, will still push industry to the brink (or beyond) of rate increases it is able to absorb before manufacturers are forced to make difficult decisions, including potentially shifting load (and corresponding jobs) out of state where electric rates are more competitive. The availability of reliable, affordable energy is one of the primary drivers my company considers when it decides where to site or expand our operations.

In addition, I believe Duke's proposed Carbon Plan fails to provide an "all-in" total cost and rate impact estimate encompassing all projected capital spending planned in the coming years, both related and unrelated to the Carbon Plan. Duke also failed to provide certain costs that are common across all portfolios. This is concerning because it means the Commission is being asked to decide—without the benefit of complete and accurate cost and rate impact information—issues such as whether Duke's proposed Carbon Plan complies with least-cost principles and whether Duke's proposed Carbon Plan constitutes the "reasonable steps" to carbon emissions reductions contemplated by House Bill 951.

CIGFUR encourages the Commission to approve Duke's pursuit of subsequent license renewals (SLRs) for its nuclear fleet but does believe more visibility and transparency is needed into these projected costs, which are not currently accounted for in Carbon Plan estimated rate and bill impacts. In addition, many CIGFUR member companies believe natural gas has an important role to play as a bridge fuel to facilitate the energy transition. utilize the general and specific discretion it was delegated through the passage of HB 951, especially pertaining to the time frame for compliance with the carbon emissions reduction goals set forth in the legislation. Compliance in years later than 2030 allows for costs to be spread out over a longer period of time, thus helping to make the year-over-year rate impacts for ratepayers more manageable and ensuring that the least-cost plan is selected. In addition, it enables North Carolina to be flexible and in a position to adapt to new information or technology advancements or any number of other changed circumstances that could call for altering the path forward in the future. For these reasons, CIGFUR supports the "check and adjust" strategy recommended by Duke Energy. Finally, I note that all portfolios follow a similar trajectory to achieve net-zero emissions by 2050. For these reasons, the Commission should not feel pressured to abide an aspirational interim compliance goal of 2030.

This concludes my summary.

MS. CRESS: Thank you. And I would also ask that witness Muller's Exhibit Numbers 1 and 2 be marked as labeled for the record.

CHAIR MITCHELL: Motion is allowed.

(Muller Exhibits 1 and 2 were identified as they were marked when prefiled.)

MS. CRESS: Thank you. CIGFUR witness Muller is now --

CHAIR MITCHELL: I'm sorry. For the record, the documents will be marked as they were when prefiled.

MS. CRESS: Thank you, Chair Mitchell. The witness is now available for questions from the parties as well as the Commission. Thank you.

CHAIR MITCHELL: All right. CCEBA?

MR. BURNS: Yes, ma'am.

CROSS EXAMINATION BY MR. BURNS:

Q. John Burns for CCEBA. Good to meet you today, sir. I just have a few questions, and I'll try to go through them so that you can return to Charlotte as quickly as possible.

A. Thank you.

Q. As I understand your testimony, Mr. Muller, you contend -- let me start a little earlier than that.

Based on your bio as attached as -- I think it's Attachment A to your testimony, you currently lead the government affairs, marketing, and corporate communication for Charlotte Pipe; is that correct?

A. Correct.

Q. And you've been VP of corporate communications of that company since 2002?

A. Correct.

Q. Prior to that, you were a senior account executive at Price/McNabb, and an account supervisor at Edelman Worldwide back to 1993?

A. Correct.

Q. Okay. And you had some, I thought, pretty significant interesting experience with USAID at the White House.

But did any of that that we just talked about have anything to do with the power industry or the electricity industry?

A. No. I'm not here testifying as an expert in energy. You have plenty of experts for that. I'm here to give the perspective of industrial ratepayers on various issues at stake in this -- in these proceedings.

Q. Okay. So to the extent you discuss the need for power quality to be recognized by the Commission as a metric that needs to be measured, or to the extent you talk about cost, are you trying to relate those to --

MS. CRESS: Objection. Chair Mitchell, if he could point the witness to his testimony, specific page numbers and line numbers, like we have been doing for other witnesses.

CHAIR MITCHELL: All right. Sustained.

MR. BURNS: Okay.

Q. Mr. Muller, on page 5 of your testimony, I understand you contend that the costs projected by Duke are understated; is that right?

A. (Witness peruses document.)

Yes.

Q. When you discuss the understatement of costs in the Duke portfolios, are you meaning to tie those costs to a particular technology for the generation of industry or just generally to the Carbon Plan?

MS. CRESS: Objection. Compound question.

CHAIR MITCHELL: Mr. Burns, will you restate the question? Or break it up into two questions, please.

Q. When you are referring to costs on page 5 and elsewhere in your testimony, are you referring to a specific technology?

A. There are cost drivers in there that -- that haven't been accounted for. For example, transmission costs, grid improvements, that sort of thing. Those are the type of costs we're referring to as referred to in the testimony.

Q. Thank you. Let me ask you, just for everybody's sake, to move the mike a little closer to your mouth so that folks can hear you. Thank you.

Do you agree that, for the purposes of comparing portfolios by cost, it's the differences between the portfolios that are important?

A. Not sure I understand the question.

Q. If -- you actually testified there on page 6 that the costs don't include costs common to all portfolios; is that right?

A. Correct.

Q. And when you're comparing multiple portfolios, wouldn't you -- would you agree with me that it's what's the differences among those portfolios are the relevant -- are relevant for review of the cost differences between them?

A. I'm still not sure I understand your question. What are you -- what are you trying to ask me?

Q. Well, I'm trying to ask you whether -- I'll put it this way.

Why is it important for costs common to all portfolios to be included when you're comparing one portfolio against the other?

A. Sure. I understand now. Thank you. Because they add to our total cost. At the end of the day, as a ratepayer, all those costs have to be captured. So any costs that aren't captured in the plans still exist and still have to be passed on to ratepayers.

Q. All right. You refer on page -- let me make sure I have the right cite -- page 6, actually, near the top of the page, that Duke does not include costs or rate impacts associated with grid improvement plan, GIP investments, correct?

A. Correct.

Q. Do you know whether or not the grid improvement plan will be done with or without the Carbon Plan?

A. I'm not -- I don't know. I can't answer that for Duke.

Q. Okay. Do you agree that actions that are going to be taken independent of the Carbon Plan are not costs that can truthfully be considered to be costs of that plan?

MS. CRESS: Objection to the way that counsel has characterized his question.

MR. BURNS: I believe my question was just an open question.

CHAIR MITCHELL: I'll overrule the objection.

Q. I can restate it if you'd like me to?

A. Please.

Q. Do you agree that any actions that are going to be taken independent of the Carbon Plan are not actions that will cause costs that can truthfully be considered to be part of the Carbon Plan?

A. Yeah, that makes sense. But they still add costs.

Q. Certainly. On page 13 of your testimony -- and I'll take the risk of characterizing your testimony. Please tell me whether I'm mischaracterizing it. You testify after the question that begins on line 4, "How will implementation of the Carbon Plan and the related rise in prices affect businesses considering whether to expand or locate facilities in North Carolina?"

A. Uh-huh.

Q. In response to that, you discuss the effect of cost increases and power quality issues on whether Charlotte Pipe would consider locating more facilities in North Carolina, correct?

A. Correct.

Q. And if I'm -- you said, "If Charlotte Pipe was to lose the advantage," beginning on line 13 --

A. Yeah.

Q. -- "of Duke's historically low-cost reliable high-quality power, this would likely preclude us from expanding operations and creating jobs in the DEC or DEP service territories"; is that right?

A. Correct.

Q. Would you be surprised to hear that, as of June 21st -- over at -- June 2021, 60 percent of the Fortune 500 have set climate action and renewable energy goals?

A. That doesn't surprise me, no.

Q. Are you familiar with recent economic development announcements in North Carolina, such as the location of operations for Apple, Google, Boom

Aviation, Toyota, and VinFast?

A. I'm vaguely aware of those, yeah.

Q. Would it surprise you to learn that each of those companies have sustainability in carbon reduction goals specifically for those projects?

A. No, doesn't surprise me at all, no.

Q. Isn't it true that if North Carolina can provide a clean and carbon-free supply of energy, there's just as likely to be a positive net impact on economic development as there is a negative one?

A. I don't know that I would agree with that statement. Manufacturers look at costs. I mean, it's just simple economics. And whenever we've sited a plant around the country, costs -- energy costs are one of the top priorities. In fact, we're looking at siting a plant in Midwest right now, and we've done cost studies of the power.

Q. In the Midwest?

A. In the Midwest.

Q. Would part of the studies that you're doing indicate the cost of wind power in the Midwest?

A. We're looking at it on the kilowatt-per-hour. We don't -- we don't judge the resource mix, we just ask the provider what our costs are gonna be.

Q. And would you also not judge the resource mix in North Carolina in the future, just go on the costs?

A. Well, if it would increase our costs, yeah, we would question the resource mix, certainly.

Q. Okay. Your Company has locations in North Carolina, Texas, Florida, Pennsylvania, Alabama, and Utah; is that right?

A. That's correct.

Q. Are you aware that Pennsylvania recently adopted a statewide policy to reduce greenhouse gas emissions?

MS. CRESS: Objection.

MR. BURNS: I'm asking if he's aware of the policy.

THE WITNESS: I'm not aware of it, no.

CHAIR MITCHELL: I'll overrule the objection. Please, when there's an objection, just let me rule on it before you move on.

MR. BURNS: Yes, ma'am, my apologies.

Q. You said you were not aware?

A. No.

Q. Would you agree with me, Mr. Muller, that the importance of this proceeding is not -- excuse me. The importance of the question is not the -- I write out a question for myself that makes no sense. Let me --

CHAIR MITCHELL: Mr. Muller, I need to ask you to speak into the microphone. I'm getting notices that folks who are trying to listen in cannot hear you. So please just make sure it's right in front of you. Thank you, sir.

THE WITNESS: Thank you.

Q. Would you agree with me, Mr. Muller, that how the reduction of carbon is managed through this process and the continued delivery of reliable and quality power through that transition is of importance to your Company?

A. Yes, that's why I'm testifying today.

Q. But it's not whether or not the carbon reduction actually declines or by what percentage it is, but that you continue to receive high-quality power into your facilities?

A. High-quality, low-cost power.

Q. You address, I think, in Exhibits 1 and 2 to your testimony, you have some paragraphs of some products that resulted from power supply interruptions?

A. Correct.

Q. Were either of those incidents due to power supplied by renewable power, to the best of your knowledge?

A. No. Those were weather related. But they were included to give you an example of how sensitive we are to power outages. And if you introduce variable resources to the grid and that disrupts the reliability of the grid, that affects us, and so that's why we included those.

Q. But you don't have any training or experience to determine whether or not any individual power supply disruption is related to a given technology supplying that power, do you?

A. No.

Q. Mr. Muller, if gas prices were to climb significantly while gas was a significant generator on the Duke system, that would affect your cost of power, wouldn't it?

A. Yes, it already has.

Q. And if large capital expenses are made on new gas plants and those plants lose their economic value before their useful life is expended, would that result in Charlotte Pipe paying more for power in the future?

A. I don't know. I don't know how to answer that.

Q. All right. Just one moment.

(Pause.)

Q. Thank you for your time.

A. Thank you.

MR. BURNS: No further questions, ma'am.

CHAIR MITCHELL: SACE -- well, CPSA, do you have questions?

MR. SNOWDEN: No, Chair Mitchell, we have no questions.

CHAIR MITCHELL: Okay. Questions from SACE?

MS. THOMPSON: No questions, Chair Mitchell. Thank you.

CHAIR MITCHELL: Okay. And questions from Walmart?

MS. GRUNDMANN: Yes. Thank you, Chair Mitchell.

CROSS EXAMINATION BY MS. GRUNDMANN:

Q. Good afternoon, Mr. Muller. My name is Carrie Grundmann on behalf of Walmart. I do want to return to your testimony sort of on pages 5, 6, and 7 as it relates to the projected costs and rate impacts. I want to make sure that I understand.

Are you asking that there be, sort of, an all-in rate impact for both Carbon Plan- and non-Carbon

Plan-related costs?

A. Correct.

Q. Do you think it would be helpful in that all-in estimate for there to be clear delineation by the Company between whether a cost is Carbon Plan related or not?

A. Yeah, I think that would be helpful.

Q. Does your Company actively consider whether to move particular lines of business or products to one of the other operations? I think you indicated you have some facilities in Texas and Florida and Alabama.

Do you all actively consider whether to shift production to those other locations in response to the energy prices being paid at a given facility in a different state?

A. We have the ability to move production around for a variety of reasons. That would be one. Also to meet demand, transportation, that sort of thing. But yes, we do consider that when --

Q. And so from your perspective, I think that counsel for CCEBA was asking you some questions about the costs that are common to all portfolios that you mention on page 6, lines 3 and 4.

A. Yeah.

Q. So you understand, do you not, that there are certain costs related to the Carbon Plan that weren't included in the portfolios because they would have been present in all of them, correct?

A. Correct.

Q. And as a customer, it's your perspective that you care about those all-in costs because they matter to you when you pay your bills?

A. Correct. They're on the bill, right?

Q. Thank you. Those are all the questions I have.

A. Thank you.

CHAIR MITCHELL: All right. Additional questions for the witness.

(No response.)

CHAIR MITCHELL: All right. Redirect?

MS. CRESS: Thank you, Chair Mitchell.

REDIRECT EXAMINATION BY MS. CRESS:

Q. If I could turn your attention, Mr. Muller, to page 2 of your testimony, lines 10 through 13. And I'm gonna read a sentence, and you tell me if I've read it correctly. "During my tenure with Charlotte Pipe, I gained direct firsthand knowledge and experience with many facets of Charlotte Pipe's business operations, including its manufacturing processes and energy procurement, usage, and load."

A. That's correct. And I would also add, I testified before congressional committees as an industry subject matter expert, the Small Business Administration, proceedings of the Federal Trade Commission, so I'm not -- so I do represent industry in a variety of official capacities.

Q. So while you may not be a, let's say, nuclear engineer, you are certainly very familiar with your Company's usage and procurement of energy and how reliability issues affect your Company's operations; is that fair?

A. Reliability and cost, yes.

Q. Great. Thank you.

MS. CRESS: If I could have an exhibit marked as a redirect -- let's see, CIGFUR II and III Muller Redirect Examination Exhibit Number 1. Which I will represent is Duke's response to CIGFUR Data Request 2-16, and my apologies that it is mislabeled.

CHAIR MITCHELL: All right. The document will be -- will be marked for identification as CIGFUR II and III Muller Redirect

Examination Exhibit Number 1.

(CIGFUR II and III Muller Redirect Examination Exhibit Number 1 was marked for identification.)

Q. Mr. Muller, does Duke's response to this data request indicate that costs unrelated to the Carbon Plan are excluded from the Carbon Plan total cost estimates and rate impacts?

A. Say that again, please.

Q. Sure. Does Duke's response to this data request indicate that costs unrelated to the Carbon Plan are excluded from the rate impact estimates?

A. Yes, yeah.

Q. And in addition, this data response provides a list of costs that are included; is that right?

A. Correct.

Q. Thank you.

MS. CRESS: Nothing further on redirect. Thank you.

CHAIR MITCHELL: All right. Questions from Commissioners? Commissioner Duffley? Commissioner Brown-Bland? Okay. Commissioner Clodfelter? Okay. Go ahead, Commissioner McKissick.

EXAMINATION BY COMMISSIONER McKISSICK:

Q. I appreciate you being here this afternoon, and I just have one question here, and that relates to your testimony on page 8. And beginning at line 11, it says, "Can you elaborate on the position of Duke's North Carolina ratepayers should be held harmless for South Carolina's jurisdictional allocation or share of HB 951 compliance costs in the event South Carolina rejects Duke's Carbon Plan?"

Could you elaborate further or that, in terms of sharing your thoughts, perceptions, and opinions?

A. Yeah. We don't -- as a North Carolina ratepayer, we don't think it's fair to pay for a two-state plan if one of those states is not gonna participate. That spreads greater costs across a smaller ratepayer footprint.

Q. And do you have any ideas, based upon your communication with other business -- people in business, as to what would -- might be appropriate or what you might recommend, other than just a formula that takes that into consideration?

A. I don't have a proposed solution. I just think it ought to be addressed, but it's not in the plan from, what I understand.

Q. And likewise, you testified a little earlier, I believe in response to a question about the all-in costs. I guess that was on page 5, question 1.

The thoughts you have about an all-in cost, have you spoken with other people in business and industry that share this opinion?

A. Yeah. I think I could speak for -- I'm testifying on behalf of CIGFUR, and I can speak for their membership, that they would also share this opinion, yes.

Q. And have you had any conversations with other members as to what you think might be -- what might be nominal if it were all-in cost versus substantial, in terms of your thinking about where you might manufacture goods or place orders considering your, I guess, multistate footprint?

A. Well, we make capital investments over a long horizon, so I don't -- I don't know that there would be immediate decisions made based on that. But as we look at future production, where to site plants, where to hire people, costs, energy, reliability and cost is a key driver.

Q. So if, say, the cost to a grid improvement program were not substantial, it really wouldn't make much difference in the grand scheme of things?

A. Not necessarily, yeah.

Q. Okay. Thank you. I don't have any further questions.

CHAIR MITCHELL: All right. Mr. Muller, I have a few questions for you. I won't keep you on the stand long. I know travel is --

THE WITNESS: Well, thank you for allowing me to jump the line, too, I appreciate it.

EXAMINATION BY CHAIR MITCHELL:

Q. Absolutely. In your testimony on page 9, you indicate that Charlotte Pipe operates seven plants around the U.S.

And I think I think Mr. Burns ran through the jurisdictions in which you all operate, but will you reel them off for me again?

A. Yes. Two plants in North Carolina, Pennsylvania, Texas, Florida, Utah -- Pennsylvania, Florida, and Alabama. And then we just made an acquisition of three more plants in Nebraska, Wisconsin, and another plant in Florida.

Q. Okay. When you-all make acquisitions, how significant is cost of electricity in the determination of where you're gonna locate?

A. With an acquisition, it's a factor, but not a key driving factor as if when we're buying -- or building a brand-new plant, greenfield plant. Other factors are involved in making an acquisition. Certainly the return on that acquisition.

Q. Okay. So has your recent expansion occurred by way of acquisition as opposed to new greenfield development?

A. Both. We have -- I mentioned we're siting a plant in the Midwest, that'll be an 8th -- well, and 11th plant. And then we also made the acquisition. So we're making acquisitions and growing organically with new construction.

Q. Okay. You testify also on page 10 about recent power failures --

A. Yes.

Q. -- in Monroe.

And I assume -- so that -- DEC is your service provider there?

A. Yes.

Q. There was a facility caused by a weather event, and you testified it took two days to get one plant back online due to burnt dies on the extrusion lines?

A. Yes, ma'am.
Q. Was the burnt dies on the extrusion lines, is that something that Duke had to remedy or is that something that Charlotte Pipe had to remedy?
A. We had to fix that equipment, yeah.
Q. Okay. So the two -- was -- I'm just trying to figure out if the two days' delay in getting you-all operational was a result of Duke's delay or it was work that you-all had to do internally?
A. No. It was internal repairs to the machinery.
Q. Okay. And then the repairs -- or the work necessary to get the second plant up and online, that plant -- you testified the plant was single phase, which caused multiple failures in the system.
Why is the plant single phase? That seems unusual to me, but I could be wrong about that.
A. Yeah, I can't answer that technical question. I can find out and we can provide you an answer.
Q. Okay. Do you know whether the other facility is three phase or something other than single phase?
A. I don't know.
Q. Okay. And then, you know, I'm just looking at the pictures that you have attached to your

testimony.

You know, these are pictures of -- as far as I can tell, of your equipment inside the operating facilities?

A. Yeah.

Q. And I just want to make sure. The way I understand your testimony, and you tell me if I've got it wrong, that the power failure, the outage was caused by a weather event; and then any delays in getting you all back up and running were because you had to fix the equipment inside --

A. That's correct.

Q. Okay. And just following up on the single phase versus multiple three phase question, that's not -- I understand your testimony is you don't know why you're single phase. But I'm wondering if -- and I may ask Duke this question.

But I'm wondering if it's possible to upgrade the facility to something other than single phase there and that just hadn't been done for one reason or another?

A. It's possible.

Q. Is it your understanding that, because the facility was single phase, it suffered the failure --

or it suffered the outage?

A. I'm not a technical expert to be able to answer that accurately.

Q. Okay. All right. In the other jurisdictions in which you're operating, for example, in Texas, did you-all -- have you-all had any service quality problems?

A. We've had --

Q. Let me -- I'm sorry. Let me be clear with my question. Service quality problems that have disrupted your operations.

A. There were significant weather events in Texas that disrupted operations. You remember the big freeze a couple of years ago; and they've had flooding and hurricanes. So yeah, that could be disruptive.

Q. Were you-all impacted by the cold weather event of 2021?

A. Yeah, that's what I was referring to. Yes, we were.

Q. Okay. Got it. In Texas, just to be clear for the record.

A. Yes.

Q. Okay. Okay. Well, we appreciate your testimony --

A. Thank you.
Q. -- on affordability, reliability, and adequate service.
CHAIR MITCHELL: And I will check in to make sure there are no other -- Commissioner Hughes, go ahead.

EXAMINATION BY COMMISSIONER HUGHES:

Q. A quick question. If you don't know this, that's fine. We talk a lot -- a lot of the witnesses have talked about energy efficiency and demand and, you know, there is a relationship as prices go up. I would imagine companies like yours start to look harder for ways of cutting the electric.
And I just -- with an industry like you have, is that an option? Is there -- and --
A. Uh-huh.
Q. -- do you have programs that look at, kind of -- or projects on the shelf that say, if power gets up to this price, we're gonna go ahead and do this retrofit?
A. Well, not on the shelf, but we do -- we have an economic incentive to gain as much efficiency as possible. And I'll give you a good example. We are making a massive investment in Oakboro, Stanly County,

North Carolina. We're building a $460 million new foundry greenfield that's gonna be the largest foundry in North America. And the foundry that we currently operate in downtown Charlotte is a fossil fuel melt. We use coke and cupola to melt the scrap iron.

The new plant will be electric melt, and we're gonna have six electric furnaces. And that is, obviously, moving -- transitioning from fossil fuels. We want to do our part. But also they create much more flexibility, as far as production, and they're very much more energy efficient. So that's a good example of capital investment where we do look at energy efficiency as a reason to make the investment.

Q. Thank you for that. No further questions.

CHAIR MITCHELL: Go ahead.

EXAMINATION BY COMMISSIONER McKISSICK:

Q. One quick follow-up question, sir.

If we were to look at your expenses on a location-by-location basis, I take it that each facility has its own, kind of, fixed cost?

A. Correct.

Q. For, say, labor?

A. Uh-huh.

Q. Or for -- it may vary based on number of square feet? Materials that might be used?

A. Yes.

Q. When you look at the totality of those expenses, to what extent is -- are your utility expenses? When I say utility, let's now identify and segregate that out to being electricity in this case. And I assume electricity is common for each and every one of them, even though there may be other places that use natural gas, whatever --

A. Correct.

Q. -- heating.

But what component of that cost would be isolated and related to electricity?

A. Raw materials are our biggest cost, and then electricity, and then transportation, and then labor cost. I think that would probably be the four -- the top four for us.

Q. The top four. And what -- if you had to say a percentage of your total cost, how much of that is electricity?

A. I'd hate to speculate. It's less than 50 percent, I would say.

Q. Less than 50?

A. Yeah.

Q. But more than 25?
A. Yes, sir, yeah.
Q. I'm just trying to get a sense of magnitude. Thank you, sir.
A. Yeah.

EXAMINATION BY CHAIR MITCHELL:

Q. All right. And one last question. Commissioner McKissick actually jogged the thought for me.

Are you familiar with the bills? Do you routinely review bills that the facilities in Monroe receive?
A. I don't. I don't pay the bills for the plants, no.
Q. Okay. So you've never looked at an actual bill to see -- I'm just curious as to what -- how the bill appears to the industrial customer.

Do you -- how are the electricity costs reported to you, brought to your attention?
A. We get a set of financials each month. There's an officer of the company, that's in our operating costs, so we do see a line item --
Q. Okay.
A. -- for energy costs, yeah.

Q. You indicated -- my recollection is you indicated you take -- the plants in North Carolina take service under DEC's OPTV -- is it V?

A. V, uh-huh.

Q. Okay. OPTV rate schedule.

Do you know how the OPTV rate schedule works?

A. No, I'm not familiar with that.

Q. Okay. All right.

CHAIR MITCHELL: Let me just make sure. All right. No additional questions?

(No response.)

CHAIR MITCHELL: Questions on Commissioners' questions?

MR. BURNS: None. No, ma'am.

MR. SNOWDEN: I have just a few.

EXAMINATION BY MR. SNOWDEN:

Q. Mr. Muller, I want to follow up on -- Chair Mitchell had asked you how significant the cost of electricity is in siting and acquisition. And I believe Commissioner McKissick also asked you about what share of your total costs were made up by electricity costs. And you testified that the cost of electricity is a factor in siting an acquisition.

My question is, is -- in addition to the absolute cost of energy, is volatility in energy costs a factor in -- that you care about in siting an acquisition operations?

A. Yeah, yeah, it would be.

Q. Okay. And would you agree that the recent spike in energy costs due to the change in the prices of natural gas was not a good thing for your company?

A. No.

Q. Okay. So all things being equal, would you agree that a generation portfolio that results in less exposure to those kinds of price shocks due to commodity cost changes is beneficial?

A. Well, I think there are contributing factors in the current spike in energy prices that have to do with federal energy policy that I think could be corrected. So over the long term, natural gas was extremely affordable. It was in the 2- to $3 range for years.

So energy policy has had a lot to do with those spikes in prices, and that can be corrected.

Q. Okay. Well, I appreciate that, and I'm not trying to unpack, sort of, what went into the change in energy costs.

The question is, is there an inherent benefit in a generation portfolio that reduces exposure to those kinds of rapid changes in energy prices?

A. Sure, there would be.

Q. Thank you. That's the only question I had.

MS. CRESS: Chair Mitchell, I would just offer, if you want a late-filed exhibit on the single-phase, drilling down into that further and/or a copy of the bill with personal information, you know, obviously stripped out, and any kind of usage information stripped out, to the extent that the Commission is interested in that.

CHAIR MITCHELL: I would like to request a late-filed exhibit if you could get it filed in the next 24 hours -- 24 to 48 hours, just so it comes in before the close of the hearing. And do redact any information that the customer is concerned about being made publicly known.

MS. CRESS: Will do. Thank you.

CHAIR MITCHELL: Okay. And I don't need a follow-up exhibit on the three-phase/single-phase issue.

MS. CRESS: Okay. Thank you.

CHAIR MITCHELL: Yeah. Okay. Any additional questions on Commissioners' question questions before -- none from Duke? Any from the Public Staff?

(No response.)

CHAIR MITCHELL: Okay. Ms. Cress?

MS. CRESS: Yes. Thank you. At this time, I would like to move into the record Mr. Muller's Exhibits 1 and 2 marked and identified previously, as well as CIGFUR II and III Muller Redirect Examination Exhibit Number 1.

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

(Muller Exhibits 1 and 2 and CIGFUR II and III Muller Redirect Examination Exhibit Number 1 Exhibits were admitted into evidence.)

MS. CRESS: Thank you.

CHAIR MITCHELL: All right. Go ahead.

MR. SNOWDEN: Is the witness excused?

CHAIR MITCHELL: Yes, the witness -- you may step down. Thank you very much for your testimony today, sir.

MR. SNOWDEN: Thank you. The Clean Power Suppliers Association calls John Michael Hagerty to the stand.

CHAIR MITCHELL: Mr. Hagerty, let's get you sworn in. Raise your right hand, left and on the Bible. Do you -- okay. Do you prefer to affirm?

THE WITNESS: Swearing is fine.

Whereupon,

JOHN MICHAEL HAGERTY,

having first been duly sworn, was examined and testified as follows:

CHAIR MITCHELL: All right.

DIRECT EXAMINATION BY MR. SNOWDEN:

Q. Mr. Hagerty, could you please state your full name and business address?

A. Sure. My name is John Michael Hagerty, and my business address is 1800 M Street Northwest, Washington, D.C. 20036.

Q. Who is your employer and in what capacity do you serve?

A. Sure. I am a senior associate at the Brattle Group.

Q. And did you cause to be filed under seal in this proceeding on September 2, 2022, confidential unredacted prefiled direct testimony consisting of 53 pages and two exhibits?

A. Yes.

Q. And did you cause to be filed in this proceeding on September 2, 2022, redacted public prefiled direct testimony consisting of 53 pages and one nonconfidential exhibit?

A. Yes.

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

A. I do not.

Q. And if I were to ask you the same questions under oath today, would your answers be the same?

A. Yes.

MR. SNOWDEN: Chair Mitchell, at this time, I would ask that the public version of Mr. Hagerty's prefiled direct testimony be received into the record as if given orally from the stand, and that the confidential version be moved into the confidential record of this matter.

CHAIR MITCHELL: Motion is allowed.

(Whereupon, the prefiled direct testimony of John Michael Hagerty was copied into the record as if given orally from the stand.)

PUBLIC (REDACTED) VERSION

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plan and Carbon Plan	)))))	**DIRECT TESTIMONY OF JOHN MICHAEL HAGERTY ON BEHALF OF CLEAN POWER SUPPLIERS ASSOCIATION**

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

A. My name is John Michael Hagerty. My business address is 1800 M St Northwest, Washington, DC 20036. My current position is Senior Associate for The Brattle Group ("Brattle").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I received a M.S. in Technology and Policy from the Massachusetts Institute of Technology and a B.S. in Chemical Engineering from the University of Notre Dame. I have over 10 years of experience in utility and electric power industry planning and regulatory reviews, including utility resource planning, transmission planning, valuation of renewable energy, storage, and transmission assets, wholesale market design to achieve resource adequacy requirements, and optimized approaches to economy-wide deep decarbonization. Amongst other publications, I was the lead author on a study of the Duke Energy system last year during the development of H.B. 951 legislation titled "A Pathway to Decarbonization: Generation Cost & Emissions Impact of Proposed NC Energy Legislation."[1]

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. I provide economic and financial analysis for a broad set of clients in the electric utility industry that are mostly focused on the drivers for new infrastructure investment in a decarbonizing world, including renewable energy and gas-fired

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[1] https://www.brattle.com/wp-content/uploads/2021/09/A-Pathway-to-Decarbonization-Generation-Cost-and-Emissions-Impact-of-Proposed-NC-Energy-Legislation_Revised-September-2021.pdf

generation resources as well as transmission assets. My clients include electric utilities, renewable energy and storage developers, transmission developers, system operators, environmental organizations, and state agencies.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION OR OTHER REGULATORY BODIES?

A. I have not testified previously before the North Carolina Utilities Commission. I previously testified before the Public Service Commission of Wisconsin on behalf of Wisconsin Public Service Corporation ("WPSC") and Wisconsin Electric Power Company ("WEPCO"), regarding the cost effectiveness and system benefits of two facilities: (1) a natural gas-fired reciprocating internal combustion engine generating facility that WEPCO and WPCS proposed to construct and (2) a solar and battery energy storage system that WEPCO and WPCS proposed to acquire. I have also previously testified before the Alberta Utility Commission in Canada concerning the costs of new gas-fired resources in the Alberta Electric System Operator market. I submitted affidavits to the Federal Energy Regulatory Commission ("FERC") concerning the costs of new and existing generation resources on behalf of PJM Interconnection, LLC., end of life transmission planning processes on behalf of LS Power, and transmission needs for transportation electrification on behalf of Michigan Electric Transmission Company. I have also co-written filed regulatory reports to the California Public Utilities Commission on the benefits of a new high-voltage transmission facility and to the Public Service Commission of the District of Columbia on electricity demand growth from transportation and heating electrification.

Q. PLEASE DESCRIBE THE WORK BRATTLE PERFORMED IN SUPPORT OF CPSA'S INITIAL COMMENTS ON THE CARBON PLAN.

A. I reviewed the draft Carolinas Carbon Plan ("Carbon Plan") and evaluated options for Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") (collectively, "Duke") to achieve the 70% carbon reduction mandate of H.B. 951. To inform that evaluation, I conducted modeling simulations of generation and storage resources in Duke's service territory to identify alternative generation and storage resources portfolios, specifically evaluating the effects of the solar interconnection limit that Duke proposed in the Carbon Plan and the compliance year for achieving the 70% carbon reduction mandate.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to (1) provide an assessment of the modeling simulations Duke performed in developing the Carbon Plan, (2) summarize the alternative modeling simulation I completed to inform the Carbon Plan, (3) respond to Duke's comments regarding our modeling simulations, (4) summarize alternative approaches to transmission planning, and (5) comment on the proposed Execution Plan.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR TESTIMONY.

A. My testimony comes to the following conclusions:

- Duke's modeling simulations include flawed assumptions, including its assumptions concerning solar interconnection limits, solar plus storage configurations, nuclear small modular reactor ("SMR") costs and development timeline, onshore wind capacity, and electric vehicle demand forecast;

- Duke's flawed assumptions increase the risk of Duke not achieving the Carbon Plan mandates, or doing so at higher cost to its ratepayers;
- Duke should increase the solar interconnection limits in its modeling simulations, while reflecting reasonable assumptions about the higher costs and risks of doing so that are based on technical analysis of their transmission system, instead of relying on their judgment of indicative trends;
- Duke's supplemental modeling relies heavily on the addition of a 285 MW nuclear SMR in mid-2032 to achieve the Carbon Plan mandates, even though the costs of this technology are unsupported, the selected technology has not yet received regulatory approval, and the nuclear industry has a recent track record of cost overruns and schedule delays;
- Despite the reliance on nuclear SMRs, the supplemental modeling runs (specifically SP5 and SP5 High Solar Interconnection) represent an incremental improvement over Duke's initial portfolios by (1) identifying more solar additions compared to P2, (2) incorporating new configurations of solar paired with storage, and (3) increasing the amount of battery storage paired with solar, all of which support CPSA's recommendation on higher near-term solar procurement;
- Our modeling demonstrates that the higher solar interconnection limit proposed by CPSA will increase projected solar additions and reduce the total costs of achieving the Carbon Plan requirements;
- Duke's criticisms of our modeling are unfounded. In particular, our modeling adequately accounts for system reliability, as evidenced by the fact that I

identify similar additions of gas CC (2,400 MW), gas CTs (up to 1,100 MW), and battery storage (2,300 – 4,200 MW) by 2032 to replace retiring coal plants and maintain system reliability;

- Duke should leverage existing experience across the power sector industry to establish a comprehensive and proactive transmission planning process for the Carolinas that will facilitate the achievement of the Carbon Plan mandate.

I. MODELING ISSUES

(a) Concerns with Duke's Modeling Assumptions

Q. DO YOU HAVE ANY CONCERNS WITH THE ASSUMPTIONS THAT DUKE INCLUDED IN ITS MODELING ANALYSIS FOR THE CARBON PLAN?

A. Yes. There are several issues with their modeling assumptions that are problematic. The most concerning modeling assumption is the interconnection limit set on new solar resources. In addition, I have concerns about Duke's modeling assumptions regarding the costs and configurations of solar paired with storage, the assumed costs and availability of new nuclear small modular reactor (SMR) plants, the assumed amount of onshore wind available for development in the Carolinas, and the projected demand from electric vehicles. Finally, I am concerned about Duke's approach to setting the annual CO_2 emissions in the years following achievement of 70% reduction relative to 2005 CO_2 emissions. In the sections below, I explain my specific concerns and the impacts of Duke's flawed assumptions.

Q. WHAT ARE THE IMPLICATIONS OF THESE CONCERNS REGARDING DUKE'S MODELING ON THE CARBON PLAN?

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A. The cumulative implications of the concerns I have with Duke's Carbon Plan modeling is that they risk not achieving the requirements of the Carbon Plan by: (1) restricting the addition of solar in the near-term based on limited analysis and evidence, (2) relying on their aggressive assumptions with regard to the feasibility of new nuclear SMRs and onshore wind, and (3) under-forecasting total demand by 2032. The inability to develop sufficient onshore wind or nuclear SMRs by 2032 along with the potential for higher-than-forecast demand will risk coming up short on the CO_2 reduction goals. In addition, unsupported restrictions on new solar additions would likely increase future system costs. Duke can take step in the short-term to limit the risk of not achieving the CO_2 emissions reductions goals by increasing near-term procurements of solar generation above the currently proposed solar interconnection cap.

Q. CAN YOU PLEASE EXPLAIN YOUR CONCERN WITH DUKE'S SOLAR INTERCONNECTION LIMIT ASSUMPTIONS?

A. Duke sets an annual limit on how much solar capacity can interconnect to its system prior to the potential compliance dates. Duke applies a lower limit to the portfolios in which it sets the compliance date as 2032 or 2034. Duke applies a slightly higher limit to P1, the only portfolio that targets 2030 compliance. Duke's assumed interconnection limit allows 4,500 MW of new solar capacity to interconnect by 2030 in the low case and 5,400 MW in the high case.

Duke provides several considerations in the Carbon Plan and its testimony that inform their engineering judgment regarding the amount of solar capacity that can interconnect in a given year. The primary considerations are based on indicative trends in solar development and interconnection and not on detailed technical analysis that support the specific limits proposed. Their considerations include challenges associated with the interconnection process, including studying the interconnection requests to identify the necessary upgrades, and building upgrades in transmission constrained zones. However, as discussed in the direct testimony of CPSA witness Ryan Watts, Duke does not provide any technical analysis that would support the specific values they have assumed. Therefore, it is unclear how each of the considerations Duke raises on interconnection challenges relate to the specific capacity limits imposed on their modeling assumptions. The basis Duke provides also does not account for the potential between now and 2030 or 2032 to continue to improve their transmission planning process and allow for greater quantities of low-cost solar resources to interconnect to its system.

By limiting capacity additions of the lowest cost renewable energy resources available, Duke increases both costs to ratepayers and the risk that Duke will not meet the carbon reduction mandates of H.B. 951. As I will describe below, both the results of Duke's supplemental modeling and our modeling simulations in GridSIM demonstrate that the solar interconnection limit results in an increase in system costs.

Q. HOW COULD DUKE BETTER IDENTIFY THE LEAST-COST RESOURCE MIX TO MEETING THE CARBON PLAN GOALS WITHOUT THE SOLAR INTERCONNECTION LIMIT?

A. Identifying the least-cost resource mix to achieve the Carbon Plan must account for both generation and transmission costs. The least-cost generation and transmission resource plan can be identified either through including more detailed assumptions in a model, like EnCompass or GridSIM, that roughly co-optimizes generation and transmission expansion or by running multiple scenarios that consider different transmission expansion options.

For example, Duke included a transmission interconnection cost adder to its estimate of solar costs and other resources. However, they applied that interconnection cost adder to new solar only up to the imposed capacity limit, and then did not allow any additional solar capacity beyond that limit. This approach implies that there is no cost at which more solar and its associated transmission upgrades could be built beyond the assumed limit. Duke claims that the solar interconnection limit is justified because (1) the "[a]reas that are most viable for solar development from a land availability / land quality standpoint are primarily located in transmission constrained regions" and (2) cites the "transmission expansion needs and the time to construct new transmission infrastructure to accommodate increasing levels of renewables and other resources." Both of these limitations could be reflected in their modeling through higher interconnection cost assumptions at increasing levels of solar penetration, instead of completely cutting off the potential for additional solar development. For example, Duke could develop reasonable cost estimates based on the potential locations of new solar resources and the transmission system capability, or based on the network upgrades costs identified through the interconnection queue process. The estimated incremental interconnection costs for additional solar could then inform a step function in which transmission interconnection costs increase as greater amount of transmission upgrades are necessary to interconnect more solar.

For example, in its 2020 study the North Carolina Transmission Planning Collaborate ("NCTPC") studied the transmission upgrades and associated costs to interconnect offshore wind resources in its service territory. Duke then relied on the results of that study to determine the assumptions to include in its Carbon Plan simulation concerning the likely locations where offshore wind resources would interconnect into its system and the costs of the transmission upgrades.[2]

The California Public Utility Commission uses this approach in identifying the lowest cost resource mix to achieve similar carbon reduction goals in its Integrated Resource Planning process.[3] As shown in Table 1 below, the capacity expansion model assumes that additional transmission costs (shown in column 2 as "Incremental Deliverability Cost ($/kW-year)") will be necessary after a certain amount of resources are built in a renewable energy zone (shown in the three right-most columns).

[2] Draft Carbon Plan Appendix P at 16.
[3] https://files.cpuc.ca.gov/energy/modeling/Inputs%20%20Assumptions%202019-2020%20CPUC%20IRP%202020-02-27.pdf at 55.

Table 1: Incremental Transmission Costs in California Public Utility Commission Integrated Resource Planning Studies1

Transmission Zone or Subzone	Incremental Deliverability Cost ($/kW-yr)	FCDS Availability on Existing Transmission, Net of Post-2018 COD Baseline Capacity (MW)	Energy-Only Availability on Existing Transmission (MW, Default) ***	Energy-Only Availability (MW, Sensitivity) ****
Carrizo	$10	187	0	700
Central_Valley_North_Los_Banos	$36	791	0	500
GLW_VEA	$14	596	0	1470
Greater_Imperial	$221	919	1900	1900
Greater_Kramer	$48	597	0	0
Humboldt	$999**	0	100	100
Inyokern_North_Kramer	$161	97	0	0
Kern_Greater_Carrizo	$21	784	700	3680
Kramer_Inyokern_Ex*	$999**	0	0	0
Mountain_Pass_El_Dorado	$7	250	2150	3790
None	$0	0	0	0
North_Victor	$161	300	0	0
Northern_California_Ex*	$999**	866	0	0
Riverside_Palm_Springs	$88	2665	2550	3100
OffshoreWind_UnknownCost	$999**	0	0	0
Sacramento_River	$19	1995	2600	2600
SCADSNV	$102	2434	6600	10260
Solano	$21	599	700	700
Solano_subzone	$999**	0	0	0
Southern_California_Desert_Ex*	$999**	862	0	0
SPGE	$7	675	700	4080
Tehachapi	$13	3677	800	1800
Tehachapi_Ex*	$999**	0	0	0
Westlands_Ex*	$999**	1779	0	0

* Resources that end in "Ex" refers to areas outside of the CAISO transmission cost and availability estimates

Source: https://files.cpuc.ca.gov/energy/modeling/Inputs%20%20Assumptions%202019-2020%20CPUC%20IRP%202020-02-27.pdf

Alternatively, Duke could develop several alternative future transmission buildout scenarios – one with minimal solar-focused transmission upgrades and one with significant solar-focused upgrades – and identify the least-cost resource mix in each case. The total costs of the scenarios would include both the costs of the transmission upgrades and the generation resources. PacifiCorp used this approach in their 2021 Integrated Resource Planning process, by studying the optimal resource mix with and without two major transmission upgrades, including the Gateway South project and the Hemingway-to-Boardman project.[4]

Additional examples of how other system planners have co-optimized transmission and generation investment include the ERCOT Long-Term System Assessment and the Midcontinent ISO Multi-Value Project planning.

In either case, once Duke has developed alternative approaches to achieving its Carbon Plan goals, they can then analyze the tradeoffs of the alternative portfolios, including additional detailed analysis of the transmission system impacts and any risks associated with the transmission buildout, such as outage coordination. Only if the optimal resource mix either cannot be achieved through transmission planning and interconnection processes or requires significant incremental costs or risks not considered in the capacity expansion modeling, should Duke deviate from the least-cost resource mix.

Q. CAN YOU PLEASE EXPLAIN YOUR CONCERN WITH DUKE'S ASSUMPTIONS ON SOLAR PAIRED STORAGE?

A. Duke's portfolios in its Draft Carbon Plan add between 1.7 and 2.2 GW of battery storage to meet the 70% decarbonization mandate without differentiating between standalone storage and storage paired with solar ("paired storage").[5] Then in its execution plan, Duke proposes to procure 1,000 MW of standalone storage and 600 MW of paired storage.[6] However, Duke provides no information based on their

[4] https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf at 263.
[5] Carbon Plan, Executive Summary at 14.
[6] Carbon Plan, Chapter 4 at 5.

modeling results to justify the levels of economic paired storage versus standalone storage built across scenarios.[7]

Duke's proposal to rely more on standalone storage than paired storage is counterintuitive because paired storage enjoys significant cost advantages over standalone storage. First, paired resources benefit from shared interconnection facilities and upgrades. Second, paired resources benefit from the cost efficiencies of independent ownership, which would result in 45% of the capacity accruing the benefits of the Investment Tax Credit ("ITC") upfront as opposed to being normalized over the asset lifetimes for utility-owned assets. For example, assuming a 20-year asset lifetime, the capital-related costs of an IPP-owned asset (return on and of capital) are more than 15% below those of a utility-owned asset strictly due to accrual of ITC-related tax benefits upfront. Third, even assuming that Duke owns 55% of solar plus storage facilities, this translates into nearly 7% lower capital costs for paired storage facilities versus standalone facilities, which does not qualify for the Investment Tax Credit.[8]

There are additional advantages to paired storage over standalone facilities, including lower development expenses (only one site, permitting process, interconnection process, etc.) and mitigated solar energy curtailment (which could be as high as 5%-10%, not to mention clipping capture, in cases where resources

[7] Duke does provide information on standalone storage versus paired storage in its supplemental modeling runs.
[8] Note that standalone facilities will be able to qualify for the ITC going forward following the passage of the Inflation Reduction Act. We have not incorporated the changes due to the Inflation Reduction Act into our modeling simulations, as further discussed below.

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are DC-coupled). Additional deployment of solar plus storage facilities would have collateral benefits, such as potentially relieving interconnection constraints.

I would not expect all battery storage to be built paired with solar however, as there are in some cases advantages to standalone battery storage. For example, in portions of the network that are import constrained and do not have high quality sites for solar development, standalone battery storage resources would be preferred over storage paired with solar. Despite that consideration, Duke's greater reliance on standalone battery storage (1,000 MW) than paired battery storage (600 MW) remains counterintuitive and requires additional justification.

Duke's modeling assumptions did not capture all of these considerations, resulting in a bias towards selection of less economic standalone storage resources. First, Duke failed to capture the full range of cost efficiencies that paired storage resources benefit from in comparison to standalone resources. While Duke did capture the interconnection cost efficiencies associated with sharing a single point of interconnection, they failed to capture the ITC benefits of IPP-owned paired battery storage resources and did not account for the reduced development costs of paired storage.

Second, Duke assumes that in the case of DC-tied hybrid solar and storage facilities, the storage system can only charge from the solar generating facility. In fact, storage can charge from the grid if needed and only incurs minor costs to doing so in the form of incremental forfeiture of ITC benefits, and thus would economically do so during high-value events where it could not charge from the hybrid solar facility.

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Finally, Duke modelled an incomplete set of paired storage configurations. They only allowed for two configurations: 2-hour, 50% storage capacity as a share of solar capacity; and 4-hour, 25% storage capacity as a share of solar capacity scenarios. Duke should model a more complete set of scenarios, including (1) 2-hour, 25% storage capacity as a share of solar capacity and (2) 4-hour, 50% storage capacity as a share of solar capacity.

In aggregate, these changes would more accurately represent the advantages of paired storage facilities over standalone storage facilities, and would lead to the more economic outcome of prioritizing hybrid over standalone storage facilities.

Q. DID DUKE ADDRESS THE CONCERNS YOU HAVE RAISED ABOUT SOLAR PAIRED STORAGE IN ITS TESTIMONY?

A. Partially. Duke indicated that they "generally agree with intervenors that modeling additional SPS options is preferable."[9] Duke then included additional solar plus storage options in the SP5 and SP6 portfolios, specifically allowing the EnCompass model to select paired solar with a 4-hour battery storage at 50% of the solar capacity. Duke also allowed the battery storage, whether in standalone or paired configurations, to be economically dispatched. However, Duke did not adjust its assumptions regarding capital costs or the benefits of the ITC.

Q. CAN YOU PLEASE EXPLAIN YOUR CONCERN WITH DUKE'S NUCLEAR SMR COST ASSUMPTIONS?

A. Duke's capital cost assumptions for new nuclear SMR units are unreasonable and unjustified. Duke assumes total installed capital costs (overnight costs plus

[9] Modeling Panel at 153.

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AFUDC) in 2032 of [redacted] (nominal dollars) for the GE BWRX-300 Small Modular Reactor.[10] Duke provided little basis for the assumed costs in the Draft Carbon Plan. When requested for more information, Duke provided no additional sources of the costs or the underlying assumptions.[11]

As a point of comparison, the EIA AEO estimates the capital costs of nuclear SMRs of [redacted] in 2021 dollars for first-of-its-kind plants and [redacted] in 2021 dollars for nth-of-kind. The difference between the two cost estimates is the EIA's "technological optimism factor." The EIA states that they "apply the technological optimism factor to the first four units of a new, unproven design; it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit."[12] The EIA's first-of-its-kind cost is more relevant as few, if any, SMRs are expected to be completed by 2032, the earliest possible online date projected by Duke. For example, an August 2022 report by NARUC listed only two entities currently pursuing the GE-Hitachi BWRX-300 SMR design: Tennessee Valley Authority ("TVA") and Ontario Power Generators ("OPG").[13] The TVA unit is not expected to come online until at least 2032.[14]

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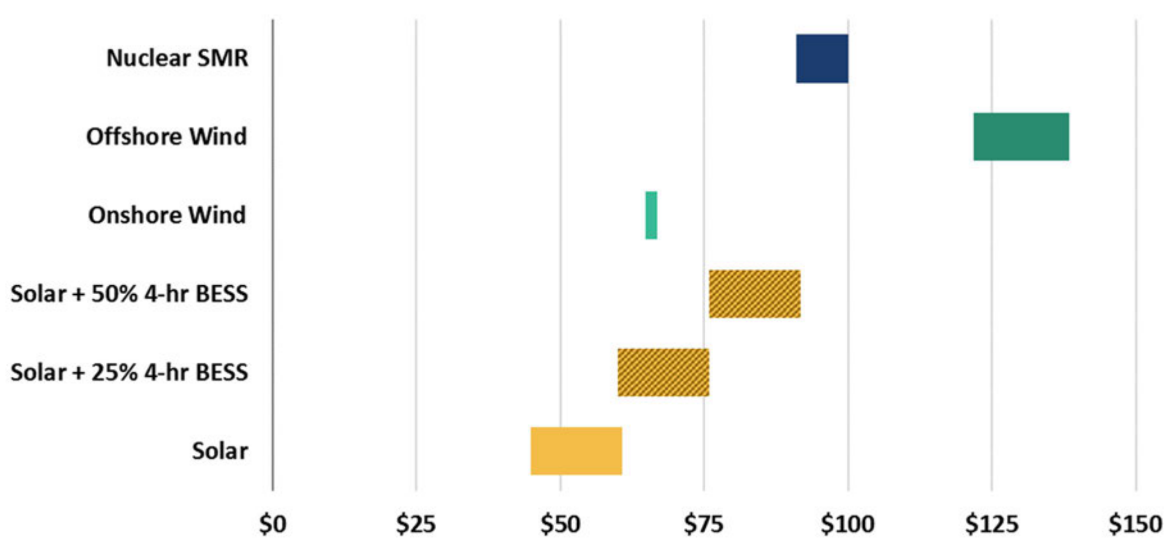
[10] Ex. 1, Duke Response to PSDR3-17 (confidential)
[11] Ex. 2, Duke Response to CPSA DR1-4.
[12] EIA, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022, at https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf (March 2022).
[13] Energy Ventures Analysis, Nuclear Energy as a Keystone Clean Energy Resource, prepared for NARUC, August 22 at 24, available at https://pubs.naruc.org/pub/916FC2AB-1866-DAAC-99FB-1A9F58CA5ECB.
[14] *Id.* 30.

To make an apples-to-apples comparison to the Duke costs, I escalated the EIA's first-of-its-kind capital costs from 2021 dollars to nominal dollars as of its commercial online date in 2032, which results in installed costs in 2032 of $9,614/kW (nominal dollars).[15] The EIA projected costs for nuclear SMRs are thus 33% higher than Duke's projected costs.

In either case, the nuclear SMR costs are significantly higher than solar, including solar paired with 4-hour battery storage (both in 25% and 50% of solar capacity configurations). Figure 1 below shows the projected range of levelized costs of several clean energy technologies in 2030. The range of renewable energy costs are based on the Moderate (lower costs) and Conservative (higher costs) projections in the 2022 Annual Technology Baseline. The range of nuclear SMR costs are based on the Duke cost assumptions (lower costs) and the EIA cost assumption (higher costs), assuming a 95% capacity factor.

Figure 1: Comparison of 2030 Levelized Costs by Technology (nominal $/MWh)



[15] EIA, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022, March 2022.

Source and Notes: Brattle analysis. The range of levelized costs for renewable energy resources are based on NREL 2022 Annual Technology Baseline costs, using the Moderate (low cost) and Conservative (high cost) cases. The range of nuclear SMR costs are based on Duke's cost estimates (low cost) and EIA cost estimates (high cost).

Duke's use of depressed nuclear cost estimates is inappropriate because it fails to adequately consider the substantial cost and development risks inherent in the development and construction of new nuclear facilities. The use of unproven technologies such as SMRs can present availability and delay risks given the limited number of vendors and available models and associated technology. Nuclear reactors may also face permitting delays related to required Nuclear Regulatory Commission ("NRC") approvals because new reactor models like the BWRX-300 have not yet obtained such approvals. In addition, fuel production, transport, and storage may present both delay and cost risks.

Duke's timeline for obtaining a CPCN for a new advanced nuclear plant[16] suggests that the NCUC would be asked to approve a CPCN based on assumptions of technology demonstration, fuel supply availability, cost, timing, federal permitting, and associated workforce and supply chain considerations that may not yet be verifiable. Duke's capital cost sensitivity analysis states that nuclear presents the second highest capital cost risk in all four Carbon Plan scenarios, up to $4 billion, and the factors described above help explain why the cost risk for these nuclear facilities is so high.

Recent delays and cost overruns associated with the development and construction of nuclear facilities are well documented. Georgia Power's Vogtle nuclear plant is now projected to cost over $30 billion, more than double its initial

[16] Carbon Plan Ch. 4 at 18-19; Appx. L at 12.

estimate, and is more than seven years behind schedule.[17] In South Carolina, SCANA and Santee Cooper spent $9 billion for the partial construction of the V.C. Summer nuclear plant before cancelling construction.[18] Duke's cancellation of the Lee Nuclear Facility also resulted in stranded construction costs that the North Carolina and South Carolina utility commissions were required to allocate.[19]

Q. CAN YOU PLEASE EXPLAIN YOUR CONCERN WITH DUKE'S ELECTRIC VEHICLE DEMAND ASSUMPTIONS?

A. Duke assumes 310,000 light-duty and nearly 12,000 medium- and heavy-duty vehicles will be electric-powered by 2030.[20] While Duke increased its estimated adoption of electric vehicles ("EV") from the 2020 IRP, these projections are well below even the more conservative forecasts for EV adoption in the United States through the early 2030s.

As I explain below, I conservatively estimate their assumptions could under-forecast EV demand by 1,050 GWh in 2030, 2,160 GWh in 2032, and 3,220 GWh in 2035. Higher electricity demand from EVs will need to be matched by increased procurement of clean energy resources, including solar, to achieve the Carbon Plan CO_2 goals. For example, an additional 2,160 GWh of demand in 2032 would require an additional 880 MW of solar. If higher demand occurs in the compliance year than forecasted by Duke and there are insufficient resources installed in its system to provide zero carbon generation, Duke will need to operate

[17] https://www.gpb.org/news/2022/05/09/georgia-nuclear-plants-cost-now-forecast-top-30-billion
[18] https://www.postandcourier.com/business/3-years-later-how-the-fallout-from-scs-9-billion-nuclear-fiasco-continues/article_5d2a2684-d264-11ea-946f-935bbd3ffa98.html
[19] https://www.greentechmedia.com/articles/read/duke-cancels-lee-nuclear-project-rate-increase
[20] Carbon Plan Appendix F at 12.

its natural gas- and coal-fired power plants more than expected, increasing emissions and coming up short on its required goal.

Based on our analysis of vehicle sales in Duke's service territory, Duke's EV forecast implies that EVs will make up about 20% of new vehicle sales by 2030. Their 2030 EV sales outlook is well below recent forecasts and policy goals. For example, the Bloomberg New Energy Finance ("BNEF") forecast estimates that 30% of new vehicle sales will be electric by 2030. The BNEF forecast is conservative relative to similar projections by IHS Markit (45% by 2030) and my colleagues and I at The Brattle Group (40% by 2030), and the policy goals set by the Biden Administration (50% by 2030).

Q. DID DUKE RESPOND TO THE CONCERNS YOU HAVE RAISED ABOUT EV ADOPTION IN ITS TESTIMONY?

A. Yes, they explained that their forecast is reasonable due to differences in adoption between their service territory and the rest of the country and the timing of when EV adoption starts increasing in the BNEF forecast compared to their forecast, such that the impact on the near-term action plan is "negligible."[21] They also note that their EV forecast aligns with the International Energy Association ("IEA") Global EV Outlook 2021.

First, Duke compares their EV forecast for North Carolina to a global EV forecast developed by the IEA. In addition, the IEA forecast that they cited was the 2021 forecast, which is now outdated. The IEA's 2022 forecast projects 33% higher EV adoption by 2030 compared to its 2021 forecast. Even if Duke's assumptions

[21] Modeling Panel at 130.

align with a single forecast, in my experience the EV adoption forecast they used is well outside the range of publicly-available forecasts.

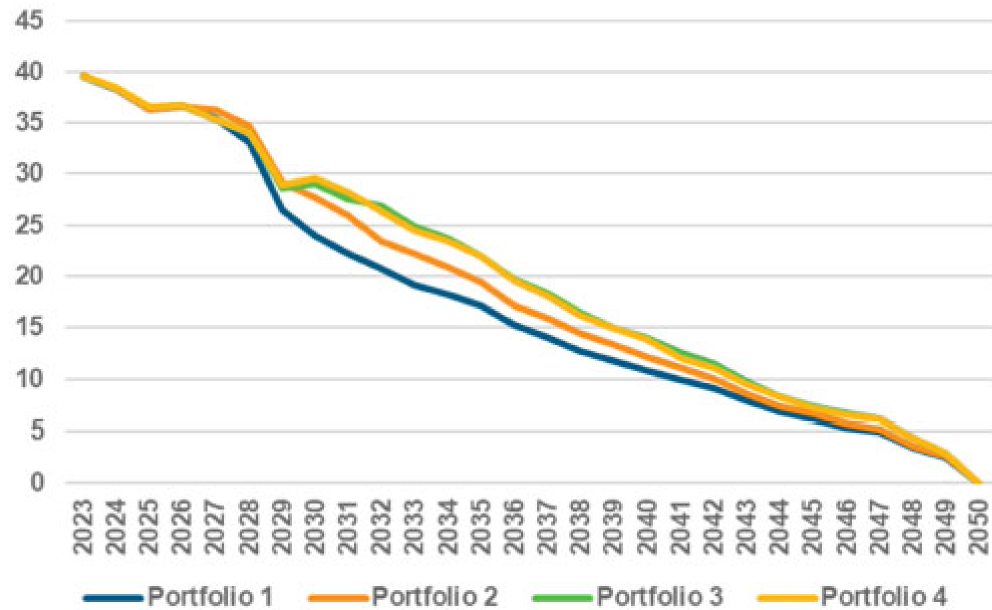
By underforecasting electricity demand and having a limited set of clean energy resources that could be developed in time to meet the Carbon Plan goals, the near-term limit on the procurements of solar resources will provide Duke less options for achieving its CO_2 emissions requirements in the case where EV adoption does increase through 2030 or 2032 faster than currently planned by Duke.

Q. CAN YOU PLEASE EXPLAIN YOUR CONCERN WITH DUKE'S CO_2 EMISSIONS LIMIT ASSUMPTIONS?

A. Yes. In its modeling, Duke set annual CO_2 emissions limits for each portfolio depending on the year in which the portfolio achieves the 70% reduction in CO_2 emission (i.e., 2030, 2032 or 2034).[22] Their approach results in lower near-term CO_2 emissions limit for P1 than the other three portfolios to meet earlier compliance dates. This approach to setting the CO_2 emissions limit up to the compliance year is reasonable. However, in the years following the compliance date, Duke continues to set lower annual CO_2 emissions limit in the P1 case compared to the other portfolios, as shown in the figure below from the Draft Carbon Plan.

[22] Carbon Plan, Chapter 3 at 26.

Figure 1: Duke Carbon Plan Annual CO2 Emissions Limits by Portfolio



Source: Duke Carbon Plan Appendix E at 79.

The lower annual CO_2 emissions limits in P1 beyond 2030 results in significantly lower cumulative CO_2 emissions in the P1 scenario compared to the other portfolios. The cumulative CO_2 emissions for 2022 to 2050 are 533 million short tons for P1, which are 7% lower than P2 (569 million short tons), 12% lower than P3 (601 million short tons), and 11% lower than P4 (599 million short tons). However, Duke does not account for the CO_2 reduction benefits of P1 in its assessments of the portfolios.

In fact, Duke does just the opposite by highlighting that P1 has the highest ratepayer costs, without also acknowledging that it achieves the most CO_2 emissions reductions. The difference in the total present value of revenue requirements ("PVRR") between P1 and P2 is $2.3 billion, just a 2% difference. In my analysis of the annual revenue requirements for P1 and P2, I calculated that at least $1.0 billion of the difference in the PVRR between P1 and P2 occurs in the years following 2032, the P2 compliance year. This demonstrates that nearly half of the cost difference between P1 and P2 is due to the differences in long-term emissions limits.

Instead of setting separate emissions goals in the later years, Duke instead should have adopted a more apples-to-apples comparison between its portfolios by aligning the long-term CO_2 emissions limits beyond the compliance dates. Without doing so, the costs of P1 are artificially increased compared to the other portfolios.

Q. CAN YOU PLEASE EXPLAIN YOUR CONCERN WITH DUKE'S ONSHORE WIND ASSUMPTIONS?

A. Duke assumes that up to 1,200 MW of onshore wind will be available by 2032 and its modeling selects 600 MW by 2030 for P1 and 1,200 MW by 2032 and 2034 for the remaining portfolios, including the supplemental portfolios (P5 and P6). However, there currently are no active requests in the DEC or DEP generation interconnection for onshore wind facilities. In addition, there is currently only one onshore wind project extant in the Carolinas – the Amazon Wind Farm U.S. East, a 208 MW facility located in Dominion's service territory.[23] While onshore wind is a well-established renewable resource globally and in other states in the U.S., the development pipeline for new onshore wind farms and the timeline for such facilities in the Carolinas is highly uncertain.

(b) Duke's Supplemental Modeling

[23] EIA Form 860, available at https://www.eia.gov/electricity/data/eia860/.

Q. DO YOU HAVE ANY CONCERNS RELATED TO THE UPDATED ASSUMPTIONS DUKE INCLUDED IN THE SUPPLEMENTAL MODELING?

A. Yes. The most significant change in assumptions that Duke made in developing its Supplemental modeling is shifting the online date for the Nuclear SMR six months earlier from the end of 2032 to the middle of 2032. As Duke notes in Appendix L of its Draft Carbon Plan, Duke finds that date is feasible for building a new nuclear plant, but also states that "2032 is the earliest possible date that advanced nuclear could be placed in service in the Carolinas."[24] They note several factors that could impact that timing of the development of the Nuclear SMR, including that the timing is "dependent on the action of the NRC"[25] and that "the project timeline for an actual project could have different permitting, licensing, construction and commissioning time frames due to design specifics of the technology chosen and potential regulatory change."[26]

I raise this as an issue since it could have significant impacts on whether Duke is able to achieve the Carbon Plan goals in 2032. Specifically, Duke assumes that the new Nuclear SMR will generate 1,400 GWh in 2032. If the Nuclear SMR does not start operating at the earliest possible date when it could be brought online, a natural gas-fired or coal-fired generation resource is likely to fill the gap, resulting in an additional 0.6 million short tons to 1.4 million short tons of additional CO_2 emissions in 2032. Duke notes that they moved up the date of the nuclear units

[24] Appendix L at 5.
[25] Appendix L at 10.
[26] Appendix L at 11

because doing so "could have a material impact on meeting the emissions reduction target,"[27] but they do not account for the potential impacts that a six-month delay in the schedule of the Nuclear SMR would have on meeting the Carbon Plan requirements.

Q. DO YOU AGREE WITH THE CHANGES TO SOLAR PAIRED WITH STORAGE AND THE DISPATCH OF BATTERY STORAGE?

A. Yes. Both of those changes in assumptions are an improvement over the previous assumptions that Duke used to develop P1 through P4.

Q. DO YOU HAVE ANY CONCERNS RELATED TO THE RESULTS OF THE SUPPLEMENTAL MODELING?

A. Yes. The final resource additions results for SP5, SP5A, SP6 and SP6A that are shown in Table SPA-12 of Exhibit 1 to the Modeling Panel testimony are misleading. In this table, the SP5 New Solar capacity (as of the beginning of 2032) is shown as 8,600 MW, which appears to be significantly greater than the 5,600 MW of New Solar that Duke listed for P2 in the Executive Summary of the Draft Carbon Plan. However, the two values are not comparable because they include cumulative solar additions over two different timeframes. The SP5 value includes all solar additions starting in 2024, while the P2 value includes solar additions starting in 2027. When put on a comparable basis, the amount of new solar additions in SP5 is 6.8 GW, as shown in the table below.[28] Notably, the higher solar

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[27] Modeling Panel at 60.

[28] Solar additions based on the detailed EnCompass output provided by Duke. P1 and P2 are from the final production cost simulation results and P5 and P5 High Solar are from the capacity expansion results.

capacity limit set in the High Solar Interconnection case resulted in 1,665 MW of additional solar, or 8.5 GW of new solar by 2032.

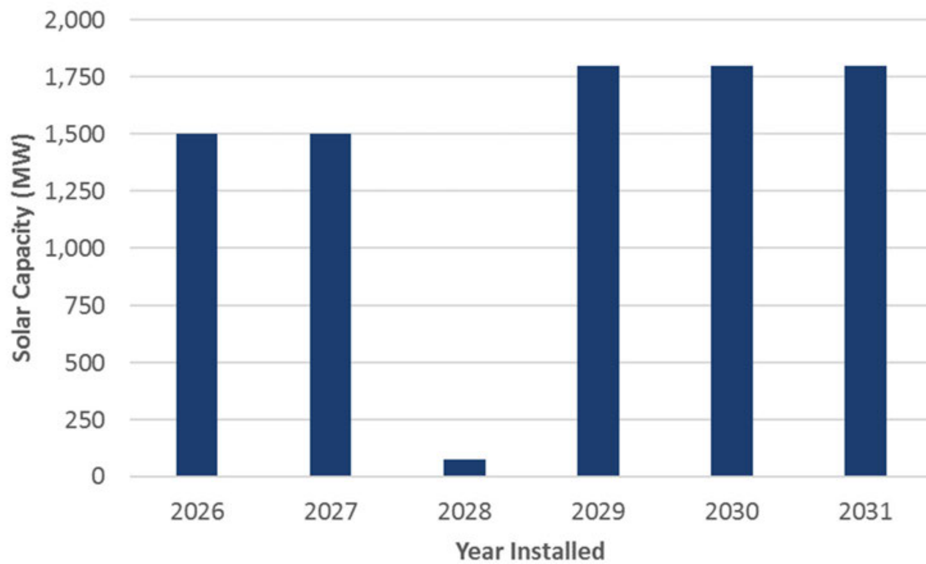
Table 2: Solar Interconnection Limits in Duke Portfolios

	Annual Solar Additions (BOY)						Cumulative Total	
Scenario	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**by 2030**	**by 2032**
P1	750	1,050	1,800	1,800	1,350	1,800	5,400	8,550
P2	375	1,050	1,050	1,050	1,050	975	3,525	5,550
P5	750	1,050	825	1,350	1,395	1,440	3,975	6,810
P5 High Solar	1,500	1,500	75	1,800	1,800	1,800	4,875	8,475

Source: Brattle analysis of Duke EnCompass modeling results

I also have several concerns related to the High Solar Interconnection case, in which Duke modeled the solar capacity additions limit as proposed by CPSA. First, their modeling selected the maximum amount of solar in each year except for 2028 when just 75 MW out of 1,800 MW of solar is installed, as shown in the figure below. I find this to be a surprising and counterintuitive result that has a significant impact on the total solar installed in this case. Long-term capacity expansion models like EnCompass minimize costs over the timeframe studied. Unless there is a significant difference in costs or a resource is unable to be built, the model is unlikely to make such a drastic change in a single year unless another constraint is limiting entry. This result seems to imply that Duke is including in its model an additional limit that is constraining solar additions in 2028. For example, Duke may be modeling the CO2 emissions to be *equal* to a certain cap in each year, instead of allowing the emissions to be *less than or equal* to that cap in each year. Applying such a limit would tend to increase the costs of achieving the Carbon Plan goals based on an arbitrary modeling assumption.

Figure 2: Annual Capacity Additions in High Solar Interconnection Case



Source: Brattle analysis of Duke EnCompass modeling results

Second, Duke reports in Table SPA-27 of Exhibit 1 to the Modeling Panel testimony that High Solar Interconnection Case selected an additional 700 MW of solar in 2035 and 300 MW in 2050 compared to the Supplemental Portfolio 5 ("SP5"). In fact, the High Solar Interconnection case results in an additional 1,665 MW of solar additions as of the beginning of 2032, which is more than 2x higher than shown in the table. By showing the lower values in 2035 instead of the much higher values in 2032, the compliance year, Duke is understating the potential benefits of a higher solar interconnection limit.

Third, another counterintuitive result of the High Solar Interconnection Limit case (shown in Table SPA-27) is the reduction of battery storage additions (700 MW lower) and gas CTs (500 MW lower) in 2035. This outcome is counterintuitive because solar provides a limited contribution to meeting the winter reserve margin, while both battery storage and gas CTs provide greater

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contributions to the reserve margin. On net, this portfolio would appear to undershoot the winter reserve margin or reduce the reliability of the system.

Q. DOES THE HIGH SOLAR INTERCONNECTION CASE RESULT IN LOWER RATEPAYER COSTS COMPARED TO P5?

A. Yes. Although Duke did not include the costs of the High Solar Interconnection case in Exhibit 1 of the Modeling Panel testimony, the detailed EnCompass output results for the High Solar Interconnection case and P5 case show that on average from 2026 to 2032 the High Solar Interconnection cases results in $40 million of cost savings per year compared to P5.

Q. PLEASE PROVIDE YOUR OVERALL ASSESSMENT OF THE SUPPLEMENTAL MODELING AND ITS IMPLICATIONS FOR THE CARBON PLAN.

A. Overall, I found that the supplemental modeling runs, specifically SP5 and SP5 High Solar Interconnection, represent an incremental but insufficient improvement over Duke's pre-existing scenarios. The improvements primarily include selecting more solar resources by 2032 compared to the P2 portfolio and incorporating new configurations of solar paired with storage. In both cases, the results support CPSA's recommendation on higher near-term solar procurement.

The SP5 High Solar Interconnection case in particular demonstrates how larger solar procurements and a more reasonable solar interconnection constraint reduces cost and execution risk for achieving interim compliance (see Tyler Norris' testimony on the limited execution risk of solar development). The P5 High Solar Interconnection case identified 8,475 MW of solar by 2032, even with (1) the unreasonable assumptions that the first SMR is available by mid-2032 at Duke's unjustified low cost estimate, (2) the assumption that 1,200 MW of onshore wind will be available, and (3) the unreasonable one year drop in solar additions in 2028.

A more reasonable Supplemental Modeling approach would have included a scenario where the availability of Nuclear SMRs was not further accelerated (i.e. from late 2032 to mid 2032) and a higher solar cap was included (e.g., the CPSA cap or the solar cap applied to P1). If the NCUC does not accept the addition of CPSA's CPSA5 scenario for 2032 compliance, CPSA recommends that NCUC require Duke to run a P5 sensitivity (or a P7) that addresses these issues.

Finally, the Supplemental Modeling demonstrates that Duke should increase its near-term targets for procuring battery storage, primarily through solar paired with storage. Both of the P5 cases identified over 4 GW of battery storage by 2032, compared to about 2 GW in the initial portfolios. In addition, more than 50% of the new battery storage capacity is coming from paired storage.

(c) Modeling Conducted by Brattle

Q. PLEASE DESCRIBE THE PURPOSE OF THE MODELING YOU CONDUCTED IN YOUR EVALUATION OF DUKE'S CARBON PLAN.

A. Under my supervision, a team of The Brattle Group consultants and I modeled the optimal generation capacity expansion and dispatch of the Duke Energy system (including both Duke Energy Carolinas and Duke Energy Progress) to address the impacts of the aforementioned flaws I identified in Duke's modeling of resource portfolios in its Draft Carbon Plan. Specifically, we analyzed a more complete set of resource portfolios that achieve a 70% reduction of CO_2 emissions from Duke

Energy's North Carolina power generation by 2030 or 2032 in order to inform the Carolinas Carbon Plan. We used an in-house capacity expansion and generation dispatch optimization model called GridSIM.

Q. WHAT IS GRIDSIM AND HOW DID YOU USE IT IN THIS CASE?

A. GridSIM optimizes capacity expansion and system dispatch in order to minimize the present value of system costs over the timeframe modeled, subject to meeting various constraints including hourly demand, seasonal capacity requirements, and CO_2 limits. The timeframe modeled in this case was 2020 to 2035, with 2020, 2025, 2030, 2032 and 2035 modeled. The total system costs of achieving the specified constraints in each modeled year is assigned a weighting based on the number of years between modeled years. The annual system costs include the levelized fixed costs of new resources and the operating costs of existing and new resources, including fuel costs and operations and maintenance (O&M) costs. The variable operating costs of existing and new resources are calculated based on simulated chronological hourly dispatch of 49 representative days, including 4 representative days within each of the 12 months and the peak demand day. The 4 days within each month are selected by accounting for differences in demand and renewable generation within each month using a clustering algorithm. The operating costs of meeting hourly demand in each representative day is assigned a weighting based on the number of days within the month to which it is representative.

The following diagram summarizes the key features of the GridSIM model.

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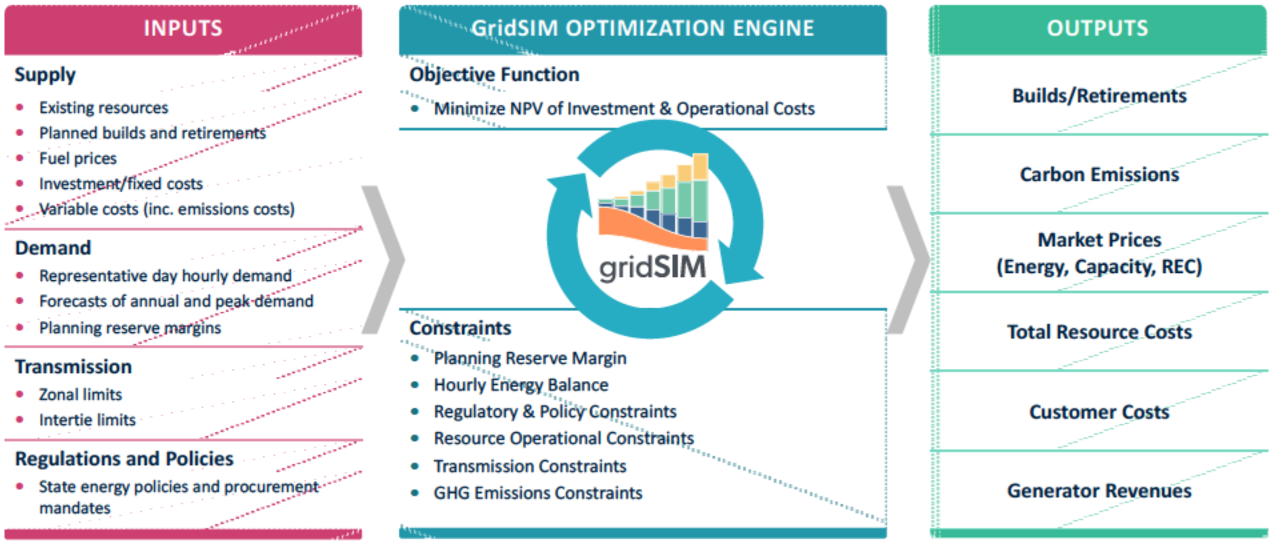
Figure 2: Summary of GridSIM Features



Q. HOW DOES YOUR MODELING ACCOUNT FOR RESOURCE ADEQUACY REQUIREMENTS?

A. Our GridSIM modeling added new generation and storage resources in order to maintain a 25% winter reserve margin, based on the results reported by Duke in Appendix E of its Carbon Plan for the resource portfolios P1 and P2. The amount of new resources required to meet the winter capacity requirement, referred to as the Capacity Shortfall, is based on our analysis of the projected winter peak demand, capacity of existing resources, and assumed contribution of each new resource to achieving the winter capacity requirement. The contribution of each new resource to achieving the winter reserve margin requirement (or effective load carrying capability, ELCC) is based on the values I estimated from Duke's Carbon Plan Appendix E for the representative range of capacity expected to be developed. For example, I assumed the new solar generation resources contribute only 2% to meeting the winter reserve margin requirement.

Q. PLEASE EXPLAIN HOW YOUR MODELING ENSURES COMPLIANCE WITH NORTH CAROLINA HOUSE BILL 951 REQUIREMENTS TO REDUCE CO_2 EMISSIONS BY 2030?

A. For each modeled year, I included separate CO_2 emissions limits for total emissions from Duke Energy's North Carolina-based resources (including all new gas-fired resources), and for total emissions from Duke Energy's South Carolina-based resources. The CO_2 limit on South Carolina-based resources is based on the annual CO_2 emissions of those resources reported in Duke's EnCompass output files for the P1 portfolio. The CO_2 limit on North Carolina-based resources is based on the assumed compliance year in which the 22.6 million short tons of emissions is achieved. For three of the portfolios I evaluated (CPSA1 through CPSA3), I assumed the compliance year is 2030. For the remaining two portfolios (CPSA4 and CPSA5), I assumed the compliance year is 2032. For CPSA4 and CPSA5, I estimated the 2030 CO_2 limit on North Carolina-based plants based on the difference between 2030 and 2032 limits reported in EnCompass input files. In all cases I modeled, I assumed the 2035 CO_2 limit is 16.9 million short tons, based on a linear reduction of the CO_2 limit from 22.6 million short tons in 2032 to achieve net zero by 2050.

Q. WHAT ARE THE MAJOR DIFFERENCES IN YOUR MODELING ASSUMPTIONS RELATIVE TO DUKE'S ENCOMPASS MODELING?

A. For the purpose of our modeling in this case, Brattle adopted most of Duke's modeling assumptions such as load growth, natural gas prices, timing of coal plant retirements, planning reserve margin requirements and contributions of each type of resource to meet seasonal resource adequacy requirements.

Our modeling assumptions differ from Duke's in five areas. First, our modeling timeframe covers the period through 2035 with the years 2020, 2025, 2030, 2032 and 2035 modeled. Duke's modeling timeframe covered all years until 2050. We have not modeled the years beyond 2035 because the modeling of those out years would have limited impact on the optimal types of resources needed to meet the 2030 or 2032 CO_2 reduction target.

Second, I assumed capital costs to install new generation and storage resources based on NREL's 2022 Annual Technology Baseline projections, with the exception of my reliance on PJM's 2026/2027 CONE Study for the cost of new gas CT. We adopted the lower capital costs of new gas CT based on the feedback I received from Duke when I presented my original assumptions and results to them prior to the release of the Draft Carbon Plan. In comparison to Duke's modeling, my capital cost assumptions in 2030 are higher for solar and natural gas CCs and CTs, and lower for onshore wind and offshore wind, as shown in the table below.

Table 3: Estimated 2030 Capital Costs (nominal dollars)

Resource	Brattle Capital Costs *$/kW*	Duke Capital Costs *$/kW*	Difference *$/kW*
Solar	$1,526	$1,380	$146
Onshore Wind	$1,325	$1,644	($319)
Offshore Wind	$3,865	$4,663	($798)
4-Hour BESS	$1,241	$1,233	$8
Gas CC	$1,422	$805	$617
Gas CT	$1,025	$711	$314

Third, our modeling evaluated sensitivities on various levels of capacity limits for model's selection of new solar generation plants. Those sensitivities include Duke's assumed limits for annual additions, CPSA's proposed limits for annual additions, and a no limit case.

Fourth, I assumed the 2035 CO_2 limit to be the same (at 16.9 million short tons) in all my cases. In contrast, as I explained above, Duke's modeling of resource portfolios assumed lower emission limits in its portfolio P1 compared to other portfolios in every year through 2050.

Fifth, and finally, I assumed that the new nuclear SMR plants would not be available to come online prior to 2035 and only 600 MW of onshore wind resources could be built by 2032. In contrast, Duke's modeling assumed new SMR plants could be available starting in year 2034 for P1 through P4, and in the middle of 2032 for its supplemental modeling (P5 and P6).

Q. HAVE YOU ALSO EVALUATED ALTERNATIVE RESOURCE PORTFOLIOS THAT DIFFER FROM THE PORTFOLIOS IN DUKE'S CARBON PLAN FILING?

A. Yes. I analyzed five alternative resource portfolios with varying limits on solar capacity additions and varying years to achieve 70% reduction in CO_2 emissions. For three of the portfolios I evaluated (CPSA1 through CPSA3), I assumed the compliance year is 2030. For the remaining two portfolios (CPSA4 and CPSA5), I assumed the compliance year is 2032.

I assumed no cap on solar capacity additions in the portfolio CPSA1, Duke's low solar cap assumptions (5,175 MW by the middle of 2030 and 7,875 MW by the middle of 2032) in portfolios CPSA2 and CPSA4, and CPSA's proposed cap on solar capacity additions (7,500 MW by the middle of 2030 and 11,100 MW by the middle of 2032) in portfolios CPSA3 and CPSA5.[29] Table 4 below shows the alternative solar caps considered by Duke and included in my simulations, showing the values in both the beginning of year ("BOY") and middle of year ("MOY") conventions.

Table 4: Duke and CPSA Annual Solar Addition Caps

Solar Cap	2026	2027	2028	2029	2030	2031	2032	2033+
Beginning of Year Convention								
Duke Low Cap	0	750	1,050	1,350	1,350	1,350	1,350	1,350
Duke High Cap	0	750	1,050	1,800	1,800	1,800	1,800	1,800
CPSA Cap	0	1,500	1,500	1,800	1,800	1,800	1,800	1,800
Middle of Year Convention								
Duke Low Cap	375	900	1,200	1,350	1,350	1,350	1,350	1,350
Duke High Cap	375	900	1,425	1,800	1,800	1,800	1,800	1,800
CPSA Cap	750	1,500	1,650	1,800	1,800	1,800	1,800	1,800

The following table summarize the key assumptions in my five alternative portfolios. Portfolios CPSA2 and CPSA3 are intended as alternatives to Duke's P1 portfolio, which assumes Duke's high cap on solar additions, with one version that is more conservative on solar additions (CPSA2 based on Duke's low solar cap) and one that is slightly more aggressive (CPSA3 based on CPSA's proposed rate of annual solar additions). Portfolios CPSA4 and CPSA5 are intended as alternatives to Duke's P2 portfolio, with CPSA4 assuming solar additions up to

[29] Note that I used the middle of the year convention as GridSIM assumes a constant amount of solar throughout the year. The middle of the year convention accounts for the average amount of solar that is forecasted to be online in a given year.

Duke's low solar cap and CPSA5 assuming solar additions up to the CPSA-proposed limit.

Table 5: Key Assumptions in Brattle Simulations

Portfolio	Compliance Year	Solar Cap
CPSA1	2030	No Cap
CPSA2	2030	Duke Low Cap
CPSA3	2030	CPSA Cap
CPSA4	2032	Duke Low Cap
CPSA5	2032	CPSA Cap

As a sensitivity to evaluate whether new SMR plants could be economic to be added to Duke's portfolio, I simulated two cases that allowed the selection of nuclear SMR plants starting in 2032. In the first case, I adopted Duke's lower capital and fixed O&M costs for nuclear SMR plants and also adjusted the solar costs to the Moderate case.[30] The second case increased the nuclear SMR costs to the EIA's capital and fixed O&M costs and increased solar costs to the ATB Conservative case. Neither case resulted in any entry of nuclear SMR by 2032.

Q. WHAT WAS THE PURPOSE OF MODELING ALTERNATIVE RESOURCE PORTFOLIOS?

A. As I explained in Section II, I have concerns about the assumptions Duke used in developing its resource portfolios. In order to illustrate the materiality of the impacts of Duke's flawed assumptions, I developed the five alternative resource portfolios.

[30] I assumed a 60 year book life for the nuclear SMRs and Duke's weighted average cost of capital to estimate the annual fixed costs for the nuclear SMRs. I allowed the unit to be fully dispatchable in GridSIM based on Duke's fuel cost assumptions.

Q. PLEASE DESCRIBE YOUR KEY FINDINGS FROM YOUR MODELING OF THE ALTERNATIVE RESOURCE PORTFOLIOS.

A. I find that restricting the amount of new capacity from solar plants in the model increases system costs. System costs increase due to the need to identify higher cost approaches to reduce CO_2 emissions, whether through the addition of alternative clean energy resources, such as offshore wind, or through shifting fossil generation away from higher emission rate resources, primarily coal. Comparing the resource portfolio in CPSA1 against CPSA2 and CPSA3 (all three of which assume the 70% reduction in CO2 emissions is achieved in 2030), I find that GridSIM selects new solar capacity additions through 2030 up to the assumed caps (7,900 MW in CPSA2 and 7,500 MW in CPSA3) and as economic in the uncapped case (9,500 MW in CPSA1). The results demonstrate that increasing solar additions reduces system costs in 2030, 2032 and 2035. Most of the solar capacity additions are paired with storage in the 4-hour at 50% of solar capacity configuration.

Second, the model selects 600 MW of onshore wind in all portfolios but offshore wind only in CPSA2 (800 MW by 2030 and 800 MW by 2032), CPSA3 (400 MW by 2030), and CPSA4 (1,100 MW by 2032). No offshore wind is selected in the case in which solar is uncapped with a 2030 compliance date (CPSA1) nor in the case with the higher CPSA cap and the 2032 compliance date (CPSA5).

Third, in all alternative resource portfolios, I find that the model economically selects a mix of gas CCs and CTs, including 2,400 MW of gas CCs in all cases with gas CTs ranging from new entry up to 1,100 MW.

Table 6: Summary of New Resource Additions and System Costs

Scenario	2030 New Solar	2032 New Solar	2030 New BESS	2032 New BESS	Onshore Wind	Offshore Wind	Gas CC	Gas CT	2030 System Costs	2032 System Costs	2035 System Costs
CPSA1 – No Cap 2030 Compliance	9,500	12,700	3,300	4,200	600 MW in 2030	---	2,000 MW in 2030	---	$6.97	$7.90	$9.13
CPSA2 – Low Solar Cap 2030 Compliance	5,200	7,900	1,800	2,700	600 MW in 2030	800 MW in 2030 and 800 MW in 2032	2,400 MW in 2030	900 MW in 2030	$7.90	$8.70	$9.84
CPSA3 – CPSA Cap 2030 Compliance	7,500	11,100	2,700	3,700	600 MW in 2030	400 MW in 2030	2,400 MW in 2030	---	$7.04	$7.97	$9.15
CPSA4 – Low Solar Cap 2032 Compliance	5,200	7,900	2,000	2,300	600 MW in 2030	1,100 MW in 2032	2,400 MW in 2030	1,100 MW in 2030	$6.78	$7.94	$9.87
CPSA5 – CPSA Cap 2032 Compliance	7,100	10,700	2,600	3,500	600 MW in 2030	---	2,400 MW in 2030	500 MW in 2030	$6.78	$7.75	$9.16

Q. DO YOUR MODELING SIMULATIONS ACCOUNT FOR THE CHANGES IN FEDERAL TAX CREDITS FOR RENEWABLE ENERGY AND STORAGE RESOURCES INCLUDED IN THE INFLATION REDUCTION ACT?

A. No, they do not. I did not incorporate any changes to our modeling following the passage of the Inflation Reduction Act due to the limited time available to do so, a desire to maintain an apples-to-apples comparison with Duke's modeling, and the need to better understand several of the provisions of the IRA related to the levels of tax credits that will be expected for each type of resource.

As a reminder, our modeling assumed the previous phase out of the federal production tax credit (PTC) and investment tax credit (ITC) with solar resources able to qualify for the 10% ITC after 2026 and offshore wind that is online by 2035 able to qualify for the 30% ITC. The IRA will significantly increase the value of tax credits for solar resources, as they now will be able to qualify for the higher value PTC. In contrast, offshore wind tax credits are expected to remain the same.

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For this reason, I do not expect that the IRA would change the mix of clean energy resources selected in our modeling simulations. However, the higher value of the tax credits will further increase the cost savings of the solar capacity additions included in each portfolio and increase the cost savings that would occur by increasing the solar interconnection limits. In addition, the extension of the federal tax credits to standalone battery storage will continue to make it an attractive alternative to natural gas CCs and CTs.

Q. WHAT WERE DUKE'S CRITICISMS OF YOUR MODELING ASSUMPTIONS AND ALTERNATIVE RESOURCE PORTFOLIOS?

A. Duke Energy's witnesses Glen Snider, Bobby McMurry, Michael Quinto and Matt Kalemba criticized our modeling assumptions for allegedly failing to be technically objective, executable, and adequately reliable.[31] They indicated that our modeling assumptions "tend to unreasonably favor grid edge, renewable, and energy storage resources, and introduce bias against firm, dispatchable resource types."[32] Furthermore, they claimed that I assumed an "improbably rapid solar deployment" while not modeling any of the years 2026 through 2029 in my simulations.[33] Finally, they criticized our modeling results as yielding "unreasonably high levels of near-term energy storage procurement",[34] and my assumptions on capital costs for building new resources as biased.[35]

[31] Modeling Panel at 183-185.
[32] Modeling Panel at 185.
[33] Modeling Panel at 191.
[34] Modeling Panel at 204.
[35] Modeling Panel at 193-194.

Q. PLEASE SUMMARIZE YOUR RESPONSES TO DUKE'S CRITICISMS OF YOUR MODELING.

A. I do not agree with any of those criticisms. Most of our modeling assumptions were designed to mimic Duke's assumptions in its draft Carbon Plan to ensure that my model results on the least-cost mix of resource portfolio does not cause any degradation of system reliability. Prior to releasing the Brattle report with our modeling findings, we presented our approach and key assumptions to Duke and asked Duke to provide feedback on any concerns they may have; Duke did not raise any concerns about "technical objectivity" of our modeling at the time. Duke raised one issue regarding my assumptions, which was that the capital cost of new gas CTs seemed too high. I therefore reduced the assumed cost of a new CT, which improved the economic attractiveness of new gas CTs in my model relative to alternatives such as new battery (with or without paired solar).

In addition, Duke's criticisms about our modeling assumptions regarding the pace of adding new solar and storage resources do not have any strong basis. I provide my responses below to Duke's specific criticisms of our modeling.

Q. HOW DO YOU RESPOND TO DUKE WITNESSES' CLAIM THAT YOUR MODELING FAILS TO MEET "TECHNICAL OBJECTIVITY"?

A. Duke's claim concerning the technical objectivity of our analysis is unfortunate and based on their own analysis does not stand up to scrutiny. As noted above and in The Brattle Group report, the analysis we completed for the Carbon Plan relied on both publicly available assumptions as well as assumptions from Duke's own modeling. We used a well-established model that Brattle has used for several clients, including the Electric Power Research Institute, the U.S. Department of Energy, the New York Independent System Operator, and other utilities as a part of their resource planning efforts. Figure 17 in the Reliability Panel testimony highlights that our assumptions concerning solar costs are in fact higher than Duke's and other intervenors.[36]

In addition, the higher solar limit in CPSA3 and CPSA5 is based on Duke's estimate of the amount of solar it can interconnect but ramping up sooner due to the unreasonably low assumed rate of interconnections in the first two years, which is supported by CPSA Witness Watts' testimony and CPSA's analysis included in its previous comments.[37] These cases test the effects of Duke's thinly supported capacity limit and whether solar additions beyond the limits imposed by Duke would provide net benefits to ratepayers.

Q. HOW DO YOU RESPOND TO DUKE WITNESSES' CONCERN THAT YOU "DID NOT MODEL ANY YEARS FROM 2026 TO 2029 WHEN DEVELOPING [YOUR] ALTERNATIVE PORTFOLIOS SO THERE IS NO MODELING JUSTIFICATION FOR THIS AGGRESSIVELY ACCELERATED PACE OF ADOPTION"?

A. The modeling I completed was intended to identify the least-cost mix of resources to achieve CO_2 emissions reductions goals by either 2030 or 2032. It is common modeling practice when running capacity expansion simulations not to include every year, especially when modeling over a longer timeframe. In this case, I

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[36] Modeling Panel at 192.

[37] See CPSA Comments (July 15, 2022), Exhibit D, *Pathways to 1800 MW Annual Solar Capacity Additions*.

modeled 2030 and 2032, as well as 2025 and 2035, to identify resource capacity additions and retirements, as those are the years in which CO_2 emissions reductions must be achieved. I gave each modeled year a weighting to reflect the number of surrounding years that it represents. In addition, I developed limits on cumulative solar additions by 2030 and then from 2030 to 2032 and 2032 to 2035 to reflect the impact of annual limits and make sure that the solar builds cannot exceed those limits. I included similar capacity addition limits on other resources, including natural gas combined cycle plants, offshore wind, and onshore wind.

Q. DUKE'S WITNESSES EXPRESS CONCERN ON PAGES 197 TO 200 OF THE MODELING PANEL THAT YOUR MODELING "FAILS TO SUFFICIENTLY ADDRESS RELIABILITY AND EXECUTABILITY." DO YOU AGREE?

A. No, I do not. Although I did not complete all of the same detailed reliability analysis that Duke did, the resource additions identified in our modeling simulations (described above) result in similar resource additions by 2032 as Duke to replace retiring coal plants and maintain system reliability, including gas CCs (2,400 MW), gas CTs (up to 1,100 MW), and battery storage (2,300 – 4,200 MW). Instead, the differences in resource mix between our simulations are primarily due to differences in solar, onshore wind, offshore wind, and nuclear SMRs.

Duke faults intervenor modeling, including ours, for failing to conduct the "Portfolio Verification" steps detailed in Appendix E. These additional steps consisted of replacing battery storage with about 1,100 MW of gas CTs in 2030 and 2032 to ensure adequate capacity during extreme winter events. However, there are two important points that Duke does not mention. First, Duke's capacity expansion modeling that occurs prior to the Portfolio Verification step did not select any new gas CTs by 2030 or 2032 for P1 and P2. In contrast, the capacity expansion modeling I completed at a similar stage did identify the need for new gas CTs in certain scenarios, adding up to 500 MW in CPSA5, 900 MW in CPSA2, and 1,100 MW in CPSA4. This demonstrates that our modeling is accounting for the value that a dispatchable resource like a gas CT would provide to the system, while Duke's capacity expansion modeling does not.

Second, Duke makes the same level of adjustment to the capacity of gas CTs and battery storage in P1 and P2, as seen in Table E-54 of Appendix E, despite significant differences in the resource mix between the two portfolios. These results indicate that higher levels of solar penetration do not result in a less reliable system.

While our capacity expansion modeling alone does not include the same steps Duke completed through its Portfolio Verification process, I do not agree that the resulting portfolios from our simulations would be less reliable. I observed based on Duke's detailed reliability analysis, including the Portfolio Verification steps, that Duke achieved a much higher winter reserve margin than their target reserve margin of 17% based on the results Duke included in Figure E-12 of Appendix E. These figures show that in 2030 to 2035 the winter reserve margin for DEP and DEC is about 25% on average, with some years higher and some years lower, for P1 and P2. To best align our modeling with Duke's and incorporate the need for additional resources beyond the planning reserve margin, we increased the planning reserve margin in GridSIM from 17% to 25%, increasing the capacity needs in 2030 by 2,300 MW and in 2032 by 2,600 MW. By adopting the higher reserve margin that Duke identified after completing its full analysis, we implicitly accounted for the resource needs that Duke identified in later stages of its analysis.

The capacity expansion modeling alone however is not equivalent to additional detailed reliability modeling that Duke completed. Similar to other portfolios, Duke should assess potential reliability issues and resource adjustments in the higher solar resource portfolios we identified as least-cost in our simulations.

Q. DUKE TAKES ISSUE WITH ALTERNATIVE MODELING THAT USES A 17% WINTER RESERVE MARGIN TO ENSURE RELIABILITY. HOW DO YOU RESPOND?

A. As I noted in response above, we assumed a 25% winter reserve margin in our GridSIM modeling runs which approximated Duke's realized reserve margins shown in Appendix E. CPSA's comments on page 31 and initial response to data requests noted a 17% winter reserve margin, but we had included in the Brattle Report attached to the comments on page 22 and later clarified in a supplemental response that our simulations assumed a 25% winter reserve margin.

II. <u>TRANSMISSION PLANNING, PROACTIVE TRANSMISSION, RZEP</u>

Q. PLEASE PROVIDE A SUMMARY OF CPSA'S RECOMMENDATIONS WITH RESPECT TO PROACTIVE TRANSMISSION PLANNING.

A. CPSA and I believe that it is critical to establish a comprehensive and proactive transmission planning process for the Carolinas. Doing so will facilitate the achievement of the ambitious decarbonization mandate of H.B. 951 and will ultimately reduce costs to ratepayers. The benefits of proactive planning are discussed both in

CPSA' comments on the Carbon Plan[38] and in the Brattle Report.[39] In its Comments, CPSA recommends that the Commission initiate proceedings, including but not limited to the convening of a technical conference, with the goal of establishing a proactive, long-term transmission planning process consistent with applicable FERC requirements.

Q. HOW DOES DUKE RESPOND TO THIS RECOMMENDATION?

A. Duke does not respond directly to CPSA's recommendation. Instead, Duke focuses narrowly on the North Carolina Transmission Planning Collaborative ("NCTPC"), stating that it is "supportive of the NCTPC initiating a review to evaluate changes to the local transmission process and to consider changes" to the provisions of Duke's Open Access Transmission Tariff ("OATT") that govern the NCTPC. Duke also indicates that it is open to a stakeholder process "to gather feedback on improvements to the local transmission planning process."[40]

Q. WOULD A CHANGE TO THE NCTPC PROCESS BE SUFFICIENT TO IMPLEMENT PROACTIVE TRANSMISSION PLANNING?

A. Probably not. As discussed in the Brattle Report, transmission planning must be combined with integrated resource planning in order to achieve maximum benefit for customers. The NCTPC as currently conceived is strictly a transmission planning entity. Although (as required by FERC) it can study public policy driven transmission improvements, it is not integrated with resource planning, a function that is under the jurisdiction of the Commission. Although it is a complex

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[38] CPSA Comments at 54-58
[39] Brattle Report at 9, 37-52.
[40] Transmission Panel at 41-42.

undertaking to integrate transmission and resource planning, RTOs and utilities across the country have implemented proactive transmission planning approaches that identify cost effective upgrades for their changing resource mix. I noted several approaches to doing so above in Section II and The Brattle Report includes several additional examples of such processes.[41]

Because the stakes are so high, it is also not sufficient for Duke to simply "gather feedback" on changes to the transmission planning process and come up with its own proposal for a revised process. Devising a new transmission planning process for North Carolina should be a truly collaborative process that ideally would reflect consensus among interested stakeholders.

Q. FERC HAS EXERCISED JURISDICTION OVER TRANSMISSION PLANNING. WHAT ROLE CAN THE NORTH CAROLINA UTILITIES COMMISSION PLAY IN SUCH A PROCESS?

A. In establishing local and regional transmission planning processes, FERC was careful to clarify that it did not intend to infringe on states' traditional authority over resource planning – and indeed, FERC believed that an open transmission planning process "can provide useful information which will help states to coordinate transmission and generation siting decisions, allow consideration of regional resource adequacy requirements, facilitate consideration of demand response and load management programs at the state level, and address other factors states wish to consider."[42] Indeed, FERC has said that it "strongly encourages state

[41] Brattle Report at 38-41, 45-47.

[42] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 at P 479 n. 274.

participation in the transmission planning process," and "encourage states to determine their own level of participation [in the transmission planning process], consistent with applicable state law."[43]

California provides one example of state involvement in the transmission planning process. During its biennial IRP cycle, CPUC identifies optimal resource portfolios needed to meet state policy goals over next 10 years, including resource type and zone. CAISO then studies whether there are reliability, economic, and/or policy needs for new transmission under each portfolio in its annual Transmission Planning Process. Stakeholders play a key role in reviewing assumptions and preliminary results, and submitting transmission upgrades for CAISO to study.[44] North Carolina could consider a similar model.

In a similar way, the New York Public Service Commission ("PSC") in 2015 identified the need for a more comprehensive approach to transmission planning than the FERC-approved planning approach completed by the New York Independent System Operator ("NYISO"). The PSC order specifically identified constraints on their system that were not being addressed and a much broader range of transmission benefits that should be considered in future planning processes to reduce costs to New York ratepayers, including longer term benefits of transmission upgrades in a decarbonizing system.[45] This example demonstrates that state commissions have a critical role to play in developing proactive transmission

[43] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 574.
[44] Brattle Report at 39.
[45] https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={6E1E021D-FD28-4F2B-84AC-35ADEE19A22C

planning processes in their state to ensure a reliable and cost effective transmission system.

III. COST EVALUATION

Q. WILL INCREASING THE SOLAR INTERCONNECTION LIMIT REDUCE COSTS TO RATEPAYERS?

A. Yes. Based on our modeling of alternative solar interconnection limits, I find that increasing the solar interconnection limit will reduce costs to ratepayers. Solar is the least-cost clean energy resource available to Duke to reduce its emissions. Even under conservative estimates of future solar costs that I included in our modeling that account for differences in contributions of resources to achieving winter reserve margin requirements, I find that raising the solar interconnection limit reduces costs. Allowing for more solar additions reduces costs by (1) avoiding the need for higher cost alternative clean energy resources, such as offshore wind and nuclear SMRs, and (2) reduces the need to dispatch higher operating cost but lower emitting fossil generation resources, such as natural gas-fired resources instead of coal-fired resources.

Duke's supplemental modeling supports this finding. Although they do not include the results in their testimony, the detailed cost information for the SP5 and SP5 High Solar Interconnection cases included in the EnCompass output spreadsheet indicates that the portfolio with higher solar capacity will reduce total system costs. While I am hesitant to rely too heavily on the results of the SP5 High Interconnection case due to the counterintuitive results I explained above, the results provide an indication that Duke's own analysis shows that an increase in the solar interconnection limit, while holding all other assumptions constant, will reduce costs to ratepayers.

IV. RELIABILITY

Q. DUKE CLAIMS ON PAGE 81 OF THE RELIABILITY PANEL TESTIMONY THAT THE INTEGRATION OF RENEWABLES CREATES RAMP RATE ISSUES THAT HAVE NEGATIVELY IMPACTED RELIABILITY IN OTHER JURISDICTION. PLEASE RESPOND.

A. The addition of more and more renewable energy resources into the power system will change the operation of the system and the dispatch of non-renewable generation resources. The daily generation profile of solar resources is predictable and results in the need for a significant increase in resources as the sun goes down and demand increases. Duke will need to have flexible resources on its system, including BESS and natural gas-fired CCs and CTs, that can ramp up during these hours to serve the daily peak demand hours. Other markets are further along in terms of wind and solar adoption and thus can provide valuable experience to Duke for preparing for the coming shift in its generation fleet.

In this case, Duke relies on market conditions in California from August 14, 2020 during a historic, once-in-35-years heatwave across several Western U.S. states and in a very different electric power system and market than the Carolinas. It is unclear how this event is applicable to Duke's system. Duke must run their own analysis of specific market conditions in the Carolinas and the Southeast to identify concerns that need to be addressed in Carbon Plan, similar to the studies completed by Astrape during the Carbon Plan analysis.

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Q. DUKE CONTENDS ON PAGE 86 OF THE RELIABILITY PANEL TESTIMONY THAT THE BRATTLE STUDY DID NOT ACCOUNT FOR PERIODS OF LIMITED OUTPUT FROM SOLAR RESOURCES IN WINTER MONTHS. PLEASE RESPOND.

A. Infrequent renewable droughts like those identified by Duke can occur and would require having sufficient dispatchable capacity available to fill in the gaps. As explained in our response to CPSA DR 2-8b, my simulations did in fact account for periods in the winter in which demand is high, but solar capacity factors are only 2 – 4%. For example, the highest demand day in December coincides with the lowest solar output of only 4% (compared to average monthly capacity factor of 13%). By including a day with high demand and low solar generation, I am accounting for the periods of limited output that the Duke witnesses claim I did not.

V. <u>EXECUTION RISKS</u>

Q. DOES THE CARBON PLAN PROVIDE A FAIR AND ACCURATE ASSESSMENT OF THE EXECUTION RISK OF DIFFERENT RESOURCES AND PORTFOLIOS?

A. No. There are a number of ways in which Duke constructs and compares its portfolios to create the false impression that portfolios that rely more heavily on solar resources present more execution risk than portfolios that rely on resources that are new to the Carolinas, like offshore wind, and resources that are completely untested in the United States, such as SMRs. Duke's misleading assessment of execution risk is discussed at length in CPSA's comments and in the direct

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testimony of CPSA Witness Norris.[46] However, I would make a few points about execution risk from a resource planning standpoint.

First, a plan that relies on a number of resources that present different execution risks should take reasonable steps to mitigate those risks. Duke seems to recognize this fact, emphasizing an "all of the above" strategy of that aggressively pursues development of many different resource types – and seeking authorization from the Commission for recovery of development costs even for resources that are ultimately not selected for a resource plan.[47] Unfortunately, as discussed in Mr. Norris's testimony, Duke's approach to solar execution risk is not to mitigate it, but to strictly limit the amount of solar it will even try to add to its system. This approach is particularly notable as the execution risk that Duke has identified for adding more solar resources are their own interconnection and transmission upgrades processes. As such, Duke has the ability to better understand, manage, and mitigate this risk.

Second, although solar interconnection rates are uncertain, it is more advantageous for ratepayers to set ambitious interconnection goals for the least-cost clean energy resource, understanding that they may not be met (with contingency plans in place if that turns out to be the case) than to set modest goals from the beginning that will not be exceeded.

Q. WHAT WOULD BE THE POTENTIAL CONSEQUENCES OF SETTING AMBITIOUS SOLAR INTERCONNECTION GOALS AND FAILING TO MEET THEM?

[46] CPSA comments at 43-47.
[47] Modeling Panel at 18; Bowman Ex. 2 ¶ 2(c)(2)(i)-(iii).

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A. Ratepayers would be no worse off than if Duke had pursued a resource plan based on a solar interconnection constraint. CPSA does not argue that the Carbon Plan should *only* include portfolios that assume higher rates of interconnection – a prudent Carbon Plan should include portfolios that reflect lower solar interconnection rates, just as it should include portfolios reflecting the possibility that SMRs might not be available by mid-2032 for compliance with the 70% carbon reduction mandate. So long as the near-term execution plan supports the entire range of modeled portfolios, then Duke can "check and adjust" its plan once Duke shows just how much solar it actually can interconnect to its system. The Commission also retains discretion to adjust compliance timelines if there are insufficient resources to achieve 70% reduction in 2030.

Q. MR. KALEMBA TESTIFIES THAT "ACCELERATING SOLAR DEPLOYMENTS BASED ON TODAY'S TECHNOLOGIES COULD CROWD OUT FUTURE, UNKNOWN SOLAR OR OTHER TECHNOLOGIES THAT ARE MORE EFFICIENT OR MORE COST-EFFECTIVE THAN TODAY'S SOLAR."[48] HOW DO YOU RESPOND TO THIS?

A. While there are likely to be significant developments in technology over the coming decade, Duke must plan today to achieve the 2032 or 2032 CO_2 emissions reduction goals. Duke should not foreclose an approach to reducing emissions in the near-term in the hope of significant technology breakthroughs over the longer-term. As a part of that, Duke should be staying on top of technology and policy developments

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[48] Modeling Panel p. 168.

in the industry and assess during each planning cycle whether new technologies are ready for primetime.

The only potential downside of procuring more solar in the near term is that customers could miss out on paying less if solar prices decline. Of course there is also the risk that prices will increase. Moreover, any cost savings that ratepayers might enjoy due to delaying solar would be more than offset by the increased costs of the non-solar resources that would need to be added to make up the shortfall in generation that results from procuring less near-term solar.'

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

MR. SNOWDEN: I would further ask that the summary of Mr. Hagerty's testimony that's been prefiled would also be accepted into the record.

CHAIR MITCHELL: That motion is allowed as well.

(Whereupon, the prefiled summary testimony of John Michael Hagerty was copied into the record as if given orally from the stand.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plan and Carbon Plan	)))))	**TESTIMONY SUMMARY OF JOHN MICHAEL HAGERTY ON BEHALF OF CLEAN POWER SUPPLIERS ASSOCIATION**

John Michael Hagerty Testimony Summary

Good morning, Commissioners. Thank you for the opportunity to appear before you today. My name is John Michael Hagerty, and I am a Senior Associate at The Brattle Group. I am appearing on behalf of the Clean Power Suppliers Association (CPSA). The conclusions I draw in my testimony are informed by my more than ten years of experience in the utility and electric power industry, a close examination of Duke's available modeling data and responses to data requests, and on extensive resource modeling conducted by my team at the Brattle Group.

In my testimony, I:

1. Assess the modeling simulations Duke performed in developing the Carbon Plan;
2. Summarize the alternative modeling simulations I completed to inform the Carbon Plan;
3. Respond to Duke's comments regarding my modeling simulations;
4. Summarize alternative approaches to transmission planning; and
5. Comment on Duke's proposed Execution Plan.

I discuss each of these items further below. But the key take-aways of my testimony are as follows. First, Duke's modeling relies on several faulty assumptions – most notably an arbitrary cap on the pace of solar interconnections – that artificially limit the amount of solar and solar plus storage that its EnCompass model can select. Second, Brattle's modeling shows that if Duke could achieve a somewhat higher rate of solar interconnections, it could save ratepayers hundreds of millions of dollars by allowing Duke to avoid relying on more expensive resources that pose significant availability and cost risk. And third, Duke has constructed the portfolios in its Carbon Plan in a way that overstates both apparent costs and execution risks of achieving compliance with the 70% carbon reduction mandate by 2030.

1. Assessment of Duke's Modeling Simulations

Duke's Carbon Plan modeling simulations include several flawed assumptions, including its assumptions concerning (1) solar interconnection limits, (2) solar plus storage configurations, (3) nuclear small modular reactor ("SMR") costs and development timeline, (4) onshore wind capacity, (5) electric vehicle ("EV") demand forecast, and (6) long-term CO2 emissions limits. The impacts of these flawed assumptions on the Carbon Plan are critical for the Commission to understand. These flawed assumptions increase the risk of Duke not achieving the Carbon Plan mandates, or doing so at higher cost to its ratepayers.

- Solar interconnection limit: Duke imposes unnecessary and unsupported hard limits on adoption of new solar capacity. Duke does not provide any technical analysis to support the specific capacity limits.

- Solar plus storage configurations: Duke's assumptions do not reflect the cost advantages of building solar plus storage configuration over standalone storage facilities, assume DC-tied configurations of storage cannot charge from the grid, and include a limited set of solar plus storage configurations.

- SMR costs and development: Duke's supplemental modeling relies on the addition of a nuclear SMR in mid-2032 to achieve the 2032 Carbon Plan mandates, even though currently there are large risks associated with the cost and development timeline of this technology.

- Onshore wind development: Duke's assumption that 1,200 MW of onshore wind could be online by 2032 is overly optimistic, as reflected in the lack of recent development in North Carolina.

- EV demand forecasts: Duke's assumed EV adoption likely under-forecasts future electricity demand. Higher demand from EVs will need to be matched by increased procurement of clean energy resources to achieve the Carbon Plan goals, or increased generation from natural gas- and coal-fired power plants that will results in Duke coming up short on its required emission reductions.

- Long-term CO2 limits: Duke set more stringent CO2 limits on portfolio "P1" from 2032 to 2050 compared to portfolio "P2", inflating the costs of portfolio that achieves 2030 compliance through higher solar capacity additions.

Duke's supplemental "SP5" and "SP5 High Solar Interconnection" model runs represent an incremental improvement over Duke's initial portfolios by: (1) identifying more economic solar additions compared to the portfolio "P2", (2) incorporating new configurations of solar paired with storage, and (3) increasing the amount of economic additions of battery storage paired with solar. Duke's own modeling results demonstrate the customer cost savings from increasing solar capacity limits.

However, there are several issues with Duke's assumptions and the results from the supplemental modeling runs. As noted above, Duke assumed that an SMR could be online in mid-2032, despite mid-2032 being the "earliest possible date" that it could be operational. Duke's supplemental modeling results tables are misleading because they show total resource additions starting in 2024 instead of 2027, as provided in the Carbon Plan Executive Summary, giving the false impression of greater solar capacity additions. In my direct testimony I provide an apples-to-apples comparison of solar capacity additions across Duke's portfolios. I also find several results from the SP5 High Solar Interconnection portfolio counterintuitive, including the selection of an unreasonably low quantity of solar capacity in 2028 and the reduction in battery storage and gas combustion turbine capacity.

2. Summary of Brattle Modeling Results

To inform the Commission's decisions on the Carbon Plan, I supervised a team of consultants from The Brattle Group that modeled the optimal generation capacity expansion and dispatch of the Duke Energy. The objective of our modeling was to address the customer cost and CO_2 compliance impacts of the aforementioned flaws I identified in Duke's modeling in support of its Draft Carbon Plan. We analyzed a more complete set of resource portfolios that achieve a 70% reduction of CO_2 emissions from Duke Energy's North Carolina power generation by 2030 or 2032 in order to inform the Carolinas Carbon Plan. These are presented as portfolios CPSA1, 2, 3, 4, and 5 in CPSA's comments and in my testimony.

These portfolios achieve 70% compliance in either 2030 or 2032, and utilize varying interconnection limit (either no limit, the limit in Duke portfolios P2-P5, and the interconnection limit modeled in the "high solar" sensitivity for supplemental portfolio P5), as follows:

Portfolio	Compliance Year	Solar Cap
CPSA1	2030	No Cap
CPSA2	2030	Duke Low Cap
CPSA3	2030	CPSA Cap
CPSA4	2032	Duke Low Cap
CPSA5	2032	CPSA Cap

CPSA requests that these portfolios be added to the Carbon Plan, and that the Near-Term Execution Plan be modified to support portfolios CPSA3 and CPSA5.

My team and I used a well-established, in-house capacity expansion and generation dispatch optimization model called GridSIM. We aligned many of our modeling assumptions with Duke's, including load growth, natural gas prices, timing of coal plant retirements, planning reserve margin requirements, and contributions of each type of resource towards meeting the seasonal resource adequacy requirements.

There are several important differences as well: (1) our modeling timeframe focused on the years most relevant to the Near Term Execution Plan and the 70% emissions reduction requirement, specifically 2025, 2030, 2032 and 2035; (2) our generation and storage costs are based primarily on costs from the National Renewable Energy Laboratory (NREL) 2022 Annual Technology Baseline, using conservative solar costs; (3) we evaluate several potential solar interconnection capacity limits; (4) we set consistent CO2 limits in 2035 across cases; and (5) we assume that SMRs are not available until after 2032 in most cases, but ran a sensitivity in which SMR could enter in 2032.

The results of our modeling simulations demonstrate that higher solar interconnection limits will increase projected solar additions and, more importantly, reduce the cost of achieving Carbon Plan requirements. For example, in the three portfolios we modeled with a 2030 compliance date, GridSIM selects economic additions of new solar up to the assumed caps by 2030 (5,200 MW in portfolio CPSA2 based on Duke's lower solar limit and 7,500 MW in CPSA3 based on CPSA's higher proposed solar limit) and further additions of new solar as economic in the uncapped case (9,500 MW in CPSA1). Notably, most solar additions are paired with storage in the 4-hour at 50% of solar capacity configuration. In addition, the results demonstrate that increasing solar additions reduces system costs in 2030, 2032 and 2035. System costs decrease with higher solar interconnection limits due to solar capacity offsetting more expensive approaches to reduce CO2 emissions, such as the addition of alternative clean energy resources or through dispatch switching towards more expensive resources with lower CO2 emissions rates.

Second, GridSIM selects the maximum allowed onshore wind capacity (600 MW) in all portfolios but selects offshore wind only in three portfolios. No offshore wind is selected when solar is uncapped with a 2030 compliance date nor with the higher solar cap and 2032 compliance date.

Third, in all resource portfolios, GridSIM economically selects new gas CCs and CTs to maintain reliability requirements, including 2,400 MW of gas CCs in all cases with gas CTs ranging from no entry up to 1,100 MW.

Finally, in a sensitivity run in which SMRs could enter in 2032, GridSIM did not select the SMRs as an economic resource to achieve compliance with Carbon Plan requirements in 2032.

The resource additions (in megawatts) and system costs (in billions of dollars) in CPSA's proposed portfolios are summarized in the following table:

Scenario	2030 New Solar	2032 New Solar	2030 New BESS	2032 New BESS	Onshore Wind	Offshore Wind	Gas CC	Gas CT	2030 System Costs	2032 System Costs	2035 System Costs
CPSA1 – No Cap 2030 Compliance	9,500	12,700	3,300	4,200	600 MW in 2030	---	2,000 MW in 2030	---	$6.97	$7.90	$9.13
CPSA2 – Low Solar Cap 2030 Compliance	5,200	7,900	1,800	2,700	600 MW in 2030	800 MW in 2030 and 800 MW in 2032	2,400 MW in 2030	900 MW in 2030	$7.90	$8.70	$9.84
CPSA3 – CPSA Cap 2030 Compliance	7,500	11,100	2,700	3,700	600 MW in 2030	400 MW in 2030	2,400 MW in 2030	---	$7.04	$7.97	$9.15
CPSA4 – Low Solar Cap 2032 Compliance	5,200	7,900	2,000	2,300	600 MW in 2030	1,100 MW in 2032	2,400 MW in 2030	1,100 MW in 2030	$6.78	$7.94	$9.87
CPSA5 – CPSA Cap 2032 Compliance	7,100	10,700	2,600	3,500	600 MW in 2030	---	2,400 MW in 2030	500 MW in 2030	$6.78	$7.75	$9.16

In particular, I want to draw attention to the differences in costs and solar capacity across portfolios with similar compliance dates.

- 2030 results for portfolios with 2030 compliance:
  - CPSA1: 9,500 MW of solar additions and $6.97 billion of system costs
  - CPSA2: 5,200 MW of solar additions and $7.90 billion of system costs
  - CPSA3: 7,500 MW of solar additions and $7.04 billion of system costs
- 2032 results for portfolios with 2032 compliance:
  - CPSA4: 7,900 MW of solar additions and $7.94 billion of system costs
  - CPSA2: 10,700 MW of solar additions and $7.75 billion of system costs

Duke's solar capacity limit (modeled in CPSA2 and CPSA4) increases costs by $860 million to $930 million for 2030 compliance and $190 million for 2032 compliance.

It is important to recall that these cost savings are very conservative because I relied on relatively high cost estimates for solar capacity. The solar costs in my modeling are 10% higher than Duke's assumptions and significantly higher than the contract price for recent solar procurements. These results demonstrate that even if the costs of solar resources were to increase due to recent supply chain challenges or increasing interconnection costs, solar capacity would still remain the most cost-effective clean energy resource to add to Duke's system.

This result is in sharp contrast to the assumptions in Duke's modeling. Duke assumes a strict capacity limit for solar additions, instead of modeling solar costs rising with increasing capacity additions. This assumption implies that there is in fact no cost at which Duke could increase solar interconnection rates on its system.

Duke's criticisms of our modeling, especially with regard to reliability, are unfounded. Our modeling assumed a higher planning reserve margin of 25% based on the results of Duke's detailed reliability studies, including its Portfolio Verification steps. We did not complete similar reliability modeling due to a lack of available time and lack of access to the models used by Duke for its reliability verification. However, by relying on the results of Duke's reliability analysis of its own portfolios, we adequately accounted for system reliability, as evidenced by the fact that GridSIM identifies similar additions of gas CC (2,400 MW), gas CTs (up to 1,100 MW), and battery storage (2,300 – 4,200 MW) by 2032 to replace retiring coal plants and maintain system reliability. The entry of gas CTs in our modeling demonstrates that GridSIM is accounting for the value provided by dispatchable resources like gas CTs, while EnCompass (Duke's capacity expansion modeling) does not. In addition, Duke's out-of-the-model adjustment to the capacity of gas CTs and battery storage is the same in P1 and P2, despite significant differences in solar capacity, indicating that higher levels of solar penetration do not result in a less reliable system and greater need for dispatchable resources.

3. Potential Approaches to Transmission Planning

All parties in this matter agree about the importance of proactive transmission planning, and the need to integrate resource planning and transmission planning. It is well understood that the current, generator-driven method of upgrading the transmission grid in a piecemeal fashion is costly and creates unnecessary delays in the development and construction of needed upgrades. Duke should leverage existing experience across the power sector industry to establish a comprehensive and proactive transmission planning process for the Carolinas that will facilitate the achievement of the Carbon Plan mandate and reduce the costs to ratepayers. Utilities and RTOs across the country have implemented proactive transmission planning approaches that identify cost effective upgrades for their changing resource mix, including PacifiCorp, California Public Utility Commission, and the Midcontinent Independent System Operator (MISO).

Importantly, proactive planning efforts will also provide the roadmap to the most cost-effective solutions for interconnection-related and other transmission needs over the next 10-20 years that will increase the rate at which new solar capacity and other resources can enter the system. Completing system-wide proactive transmission planning in parallel to the recently reformed generation interconnection process would (1) identify no-regrets system-level upgrades that can provide multiple benefits regardless of exact locations and types of resources that interconnect; (2) reduce costs, complexity, and time required for interconnecting new resources; and (3) debottleneck the process for the least-cost resources entering the system.

The Commission has an important role to play in ensuring that proactive transmission planning is incorporated into Duke's resource planning. In establishing local and regional transmission planning processes, FERC was careful to clarify that it did not intend to infringe on states' traditional authority over resource planning. Indeed, FERC has said that it "strongly encourages state participation in the transmission planning process," and "encourage states to determine their own level of participation [in the transmission planning process], consistent with applicable state law." State commissions have, in fact, taken an active role in the transmission planning process in their states. In California, the CPUC identifies optimal resource portfolios needed to meet state policy goals over the next 10 years that CAISO (the system operator of the majority of the California system) then implements in its reliability, economic, and/or policy studies to identify transmission needs. In New York, the New York Public Service Commission identified the need for a more comprehensive transmission planning approach, identifying constraints on their system that were not being addressed and a much broader range of transmission benefits that should be considered in future planning processes to reduce costs to New York ratepayers.

4. Execution Risks

In its description of the execution risks of each portfolio, Duke creates the false sense that portfolios that rely more heavily on solar resources, or achieve compliance in 2030, present more execution risk than portfolios that rely on resources that are new to the Carolinas, like offshore wind, and resources that are completely untested in the United States, such as SMRs.

In my testimony, I make two points about execution risk from a resource planning standpoint.

- Duke emphasizes that it is taking an "all of the above" strategy to mitigate execution risks on any particular resource. However, for solar, instead of developing approaches to mitigate risks associated with its development, they strictly limit the amount of solar it will even try to add to its system. This approach is particularly notable as the execution risk are their own interconnection and transmission upgrades processes, which Duke itself has the ability to better understand, manage, and mitigate this risk.

- Second, although solar interconnection rates are uncertain, it is more advantageous for ratepayers to set ambitious interconnection goals for the least-cost clean energy resource, understanding that they may not be met (with contingency plans in place if that turns out to be the case) than to set modest goals from the beginning that will not be exceeded.

To elaborate on this last point, Duke ratepayers would be no worse off if they set a higher target and came up short than if they had pursued a resource plan based on a lower solar interconnection constraint. The near-term execution plan should support the entire range of potential portfolios to achieve the Carbon Plan goals, then Duke can "check and adjust" its plan once Duke shows just how much solar it actually can interconnect to its system. The Commission also retains discretion to adjust compliance timelines if there are insufficient resources to achieve 70% reduction in 2030.

MR. SNOWDEN: Okay. And one final motion. I would ask that Confidential Exhibit 1 and Nonconfidential Exhibit 2 to Mr. Hagerty's prefiled testimony be marked for identification as premarked.

CHAIR MITCHELL: The documents will be marked for identification as they were when prefiled.

(Hagerty Confidential Direct Exhibit 1 and Hagerty Direct Exhibit 2 were identified as they were marked when prefiled.)

MR. SNOWDEN: Mr. Hagerty is now available for cross examination and Commissioner questions.

MS. CRESS: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MS. CRESS:

Q. Good afternoon, Mr. Hagerty. Christina Cress for CIGFUR.

You would agree, would you not, that the more solar interconnected to the grid, the more transmission upgrades are needed?

A. It depends on what you mean by interconnection with transmission. I'm sorry. What --

you said transmission facilities?

Q. Yeah. And why don't you qualify it for me?

A. Sure.

Q. So tell me --

A. Yeah. For every new plant, it's required to attach to the existing system, and that requires transmission facilities. To the extent that more transmission facilities beyond that point of attachment are necessary depends on where you attach those facilities.

So there might be locations on the system that have headroom where you do not need additional transmission. So if you identify those locations, it doesn't require transmission facilities beyond just attaching your plant to the point of interconnection.

Q. Okay. Thank you. Your modeling simulations do not account for the changes in federal tax credits for renewable energy and storage resources included in the Inflation Reduction Act, correct?

A. They did not.

Q. Why is that?

A. We completed our modeling before that law was passed.

Q. Okay. Are there any other reasons?

A. Not -- no.
Q. And it hasn't been supplemented since then?
A. We have not updated our analysis based on the latest tax credit policies.
Q. I think that's everything for me. Thank you.
CHAIR MITCHELL: All right. Public Staff?
MR. MOORE: No questions.
CHAIR MITCHELL: All right. Let's see if there are questions from Commissioners for the witness. Questions for the witness from Commissioners?
(No response.)
CHAIR MITCHELL: All right. All right. Mr. Hagerty, looks like you are off the hook.
MR. SNOWDEN: Chair Mitchell, I do have two very brief redirect questions.
CHAIR MITCHELL: I'm sorry, that totally slipped my mind. You may redirect.
MR. SNOWDEN: That's okay. I'll be very quick.

REDIRECT EXAMINATION BY MR. SNOWDEN:

Q. Mr. Hagerty, you would agree that the magnitude and timing of transmission upgrades that are required to interconnect any generation resource will depend very much on where those resources are sited and what they are?

A. Yes, I would agree with that.

Q. Okay. And Ms. Cress asked you if you had prepared an analysis of the impacts of the IRA, and you said you hadn't done that.

Would -- would you be willing to provide updated analysis, if it would be helpful to the Commission, reflecting their impacts of the IRA?

A. Certainly, if it would be helpful to the Commission.

Q. Thank you. Those are all the questions I have.

CHAIR MITCHELL: All right. Let me check in one more time with Commissioners.

(No response.)

CHAIR MITCHELL: All right. No questions. All right. Mr. Hagerty, you may step down. I'll entertain motions.

MR. SNOWDEN: At this time, Chair Mitchell, I would ask that Confidential Exhibit 1 to Mr. Hagerty's prefiled direct testimony and nonconfidential Exhibit 2 to his direct testimony be moved into evidence as marked.

CHAIR MITCHELL: Your motion is allowed.

(Hagerty Confidential Exhibit 1 and Hagerty Direct Exhibit 2 were identified as they were marked when prefiled.)

CHAIR MITCHELL: All right. With that, we've come to the end of our day. We will be on the record tomorrow morning at 9:00. Let's go off the record, please.

(The hearing was adjourned at 4:50 p.m. and set to reconvene at 9:00 a.m. on Tuesday, September 27, 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 29th day of September, 2022.

Joann Bunze

JOANN BUNZE, RPR

Notary Public #200707300112