NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

May 28, 2024

Ms. A. Shonta Dunston, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Docket No. E-100, Sub 190 – Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress LLC, Pursuant to N.C.G.S. § 62-110.9 and § 62-110.1(c)

Dear Ms. Dunston:

Attached for filing on behalf of the Public Staff in the above-referenced docket is the **public version** of the testimony of Dustin R. Metz of the Energy Division of the Public Staff – North Carolina Utilities Commission.

By copy of this letter, I am forwarding a copy of the redacted version to all parties of record by electronic delivery. Confidential information is located on pages 133-137 of the testimony. The confidential version will be provided to those parties that have entered into a confidentiality agreement.

Sincerely,

Electronically submitted
/s/ Lucy E. Edmondson
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Attachments

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 190

In the Matter of		
Biennial Consolidated Carbon Plan and	)	**TESTIMONY OF**
Integrated Resource Plans of Duke	)	**DUSTIN R. METZ**
Energy Carolinas, LLC, and Duke	)	**PUBLIC STAFF –**
Energy Progress, LLC, Pursuant to	)	**NORTH CAROLINA**
N.C.G.S. § 62-110.9 and § 62-110.1(c)	)	**UTILITIES COMMISSION**

May 28, 2024

Q. Please state your name, business address, and current position.

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

Q. Briefly state your qualifications and experience.

A. A summary of my qualifications and experience is attached as Appendix A.

Q. What is the mission of the North Carolina Public Staff?

A. The Public Staff represents the concerns of the using and consuming public in all public utility matters that come before the North Carolina Utilities Commission. Pursuant to N.C. Gen. Stat. § 62-15(d), it is the Public Staff's duty and responsibility to review, investigate, and make appropriate recommendations to the Commission with respect to the following utility matters: (1) retail rates charged, service furnished, and complaints filed, regardless of retail customer class; (2) applications for certificates of public convenience and necessity; (3) transfers of franchises, mergers, consolidations, and combinations of public utilities; and (4) contracts of public utilities with affiliates or subsidiaries. The Public Staff is also responsible for appearing before State and federal courts and agencies in matters affecting public utility service.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my testimony is to provide the Commission with a summary of my review and investigation of the consolidated 2023 Carbon Plan and Integrated Resource Plan (CPIRP) of Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP) (collectively, Duke or the Companies), filed in this docket on August 17, 2023; the direct testimony filed by the Companies on September 1, 2023; and the supplemental analysis along with supporting testimony filed by the Companies on January 31, 2024. My testimony also provides recommendations on the near-term action plan (NTAP).

Q. Briefly explain the scope of your investigation regarding the CPIRP.

A. The scope of my investigation included, but was not limited to, a review of: (1) capital cost assumptions for new natural gas plants and new nuclear plants; (2) transmission assumptions and energy transfers between the Companies; and (3) fuel supply in a transitioning generation fleet. In addition, I worked extensively with other members of the Public Staff regarding general modeling assumptions throughout the CPIRP review. My investigation also considered system reliability and portfolio execution.

Q. How is your testimony organized?

A. My testimony is organized as follows:

I. Summary
II. Near-Term Action Plan
III. Capital Costs of Natural Gas Plant Additions

IV.	Transmission Transfer Rate
V.	New Nuclear Generation
VI.	Fuel Supply
VII.	Transmission
VIII.	Portfolio Analysis
IX.	Reliability
X.	Carbon Intensity
XI.	Hydrogen Pilot Program
XII.	Rate Disparity
XIII.	Conclusions and Recommendations

Q. Are you providing any exhibits with your testimony?

A. Yes. I am including 4 exhibits, described below:

Metz Exhibit 1.	Public Staff Near-Term Action Plan
Metz Exhibit 2.	DEC and DEP Portfolio Summary
Metz Exhibit 3.	DEC Portfolio Summary
Metz Exhibit 4.	DEP Portfolio Summary

I. SUMMARY

Q. Please provide a summary of your testimony.

A. My testimony presents the Public Staff's proposed NTAP, a high-level overview of multiple topics in the CPIRP, a least regrets approach for multiple resource types, and pathways to implement near and short-term activities while identifying implementation risks.

My investigation concludes that the Companies' updates for natural gas and nuclear capital costs are reasonable for purposes of this proceeding, but that uncertainty exists regarding future regulations that may challenge the need for and reasonableness of future generation plants.

I also share my findings on the level of energy transfers presently occurring between DEP and DEC, as well as the more than *doubling* of power transfers from the DEP balancing area to the DEC balancing area, and the Companies' failure to factor in the cost of a transmission transfer rate in their CPIRP modeling.

My testimony provides an update on the landscape for future advanced nuclear technologies, and I support the engineering and project execution areas of the Companies' request for relief for new nuclear development. Public Staff witness Boswell discusses the accounting treatment for the request for relief in her testimony.

I further highlight the current trends of a shifting energy mix as coal generation is retired and address the need to consider fuel security with any new generation decisions.

My testimony discusses transmission impacts and provides a general summary of the most recent 2023 Carolinas Transmission Planning Collaborative (CTPC) Public Policy request, which studied the impact of over 12 gigawatts (GW) of solar and 2 GW of wind energy being injected onto the Companies' grids. Increasing the generation portfolio with limited resource diversity in the eastern part of the service territory increases the need to facilitate east to west power flows. Future resource development will likely generate the need for larger transmission infrastructure upgrades, regardless of whether the future Duke footprint is a merged utility or two independent utilities.

Next, I highlight a list of decision points that are necessary in this current CPIRP, while also identifying areas and decisions that can potentially be postponed for future resource plans, depending on which portfolio or portfolio combination the Commission determines to be reasonable.

My testimony identifies a growing concern around the reliability of the grid of the future and requests that studies be performed to inform future resource procurements and selections for CPIRP planning purposes.

I also discuss the impacts on both energy and capacity needs associated with the Companies' updated load forecast as shown in the 2023 Fall base Supplemental Planning Analysis (SPA). The magnitude of those impacts is overwhelming, and my investigation and recommendations conclude that there is no single ideal portfolio; all portfolios and sensitivities have wide-ranging pros and cons. The U.S. Environmental Protection Agency (EPA) published its final rule concerning greenhouse gas emissions under Section 111 of the Clean Air Act (CAA Rule)[1] just weeks before this testimony was filed, adding further complexity to the resource planning process. Still,

[1] *See* 89 FR 39798 (May 9, 2024).

certain actions must be taken in the near-term to plan for the retirement of existing generation and to meet load growth. The Companies' projected load growth, in my professional opinion, will have a large and significant impact on the magnitude and pace of future resource buildout. To the extent that the load growth exceeds current projections, even more aggressive actions for long lead time resources will be required. However, if projected load growth does not materialize as the Companies project, the resulting stranded assets and underutilized resources will force ratepayers to shoulder higher rates and bills than necessary.

I also provide projections of total CO_2 emissions for each portfolio considered, showing trends over the planning horizon, as well as the carbon intensity on a per megawatt-hour (MWh) basis.

The action items recommended in the Public Staff's near-term action plan (NTAP) maintain a reasonable balance of least cost planning, grid reliability, and execution risk, while striving to meet the requirements of Session Law 2021-165 (HB 951) as soon as practicable. Overall, I believe that the interconnection requirements and commercial operation of new generation technologies outlined by the Public Staff's NTAP are fairly classified as aggressive but achievable. However, because challenges are likely to occur in the implementation of the NTAP, a check-and-adjust strategy will need to be a part of all CPIRPs. Like the Companies' NTAP Proposal, The Public

Staff's NTAP proposal is an "all of the above" generation selection approach.

II. NEAR-TERM ACTION PLAN

Q. Please summarize the Public Staff's proposed Near-Term Action Plan (NTAP).

A. Listed in the table below is a summary of the Public Staff's proposed NTAP.

Technology	MW Target	Date
Solar	6,700	2031
Battery Storage	2,700	2031
Onshore Wind	1,800	2033
Combustion Turbines	849	2030
Combined Cycle	1,359	2030
Pumped Storage Hydro	1,834	2034
Advanced Nuclear	1,200	2036
Offshore Wind	2,200	2034-2035

Listed below is a side-by-side comparison of Duke's NTAP and the Public Staff's NTAP.

	Duke NTAP		Public Staff NTAP	
Technology	**MW Target**	**Year**	**MW Target**	**Year**
Solar	6,460	2031	6,700	2031
Battery Storage	2,700	2031	2,700	2031
Onshore Wind	1,200	2033	1,800	2033
Combustion Turbines	1,700	2032	849	2030
Combined Cycle	6,800	2033	1,359	2030
Pumped Storage Hydro	1,834	2034	1,834	2034
Advanced Nuclear	600	2035	1,200	2036
Offshore Wind	2,400	2034	2,200	2034-2035

A more detailed list of the Public Staff's NTAP can be found in Exhibit 1 to my testimony. I discuss the Public Staff's recommendations for each resource in more detail below and request that the Commission consider my testimony when developing and adopting an updated Carbon Plan in this biennial proceeding.

Q. Please list and explain each of your recommendations for solar photovoltaic (PV) technology.

A. I recommend targeting a minimum 6,700 MW of solar resources to be in-service by 2031, given the increased load projections presented by Duke in its supplemental analysis filed with the Commission on January 31, 2024.

The 2023 solar procurement is underway currently, and the Companies' 2024 procurement targeting 1,585 MW is under Commission review. The

Public Staff's NTAP proposal identifies 2025 and 2026 solar procurements with targeted in-service dates of 2029 and 2030. The MW target listed in the Public Staff's NTAP summary table above suggests a procurement target of 1,350 MW for the 2025 procurement cycle, to be in service by 2029, and 1,875 MW for the 2026 procurement cycle, to be in service by 2030. Evenly distributing these targets suggests a target of 1,610 MW for each procurement cycle, 2025 and 2026.

Further, the results found in multiple portfolios demonstrate the continued value of battery storage such that, to address reliability concerns, the targeted solar procurement targets should also increase the Companies' proposed ratio of solar plus storage (SPS) to stand-alone solar. Each solar procurement should target SPS to compose 50% to 85% of the total procurement, with DEP targeting 85% of the procurement to be SPS with the remainder to be stand-alone solar. The Companies should also consider procuring batteries of varying storage capacity and duration, rather than the standard 4-hour, 35% storage-to-solar capacity ratio that Duke sought in the 2023 and 2024 procurement cycles.

Additionally, the Companies should propose future proactive transmission projects to the appropriate transmission planning organization (i.e., CTPC or Southeastern Regional Transmission Planning process (SERTP)), while providing updates to the Commission on progress in future CPIRPs. The Commission <u>should not</u> approve the proposed RZEP 2.0 projects at this time, as requested in Bowman Exhibit 1 Request for Relief. I discuss further below my reasons for this recommendation.

Given the impacts of trending reliability concerns of resource curtailments, ramping, Lowest Reliable Operating Limit (LROL) capacity, cycling of nuclear generation, and increasing power flows from DEP East to DEC, the Companies should report in the next CPIRP on a longer-term projection of future solar interconnections prior to adverse conditions occurring, or being projected to occur, on the transmission and generation systems. The report should, among other things, (1) take into account the amount of standalone solar and SPS that can be interconnected in each balancing area, (2) address low load and shoulder seasons and the impacts on operating reserves, and, to the extent practicable, (3) project the level of solar curtailments from 2030 through the next 10 years that will occur with a nominal 20,000 MW of incremental solar (60/40 split between DEP and DEC) above the currently interconnected amounts. The Public Staff agrees to work with the Companies to further define the scope of the overall report. The final report should be included in Duke's initial filings in the next biennial CPIRP proceeding. Further, the report's limits, if any, on future procurements and annual interconnection should be utilized as a model sensitivity at a minimum.

Q. Please list and explain each of your recommendations for battery storage technology.

A. I recommend that the Companies develop and deploy an additional 475 MW of standalone battery storage over and above the amount identified in the Commission's final order issued on December 30, 2022, in the Carbon Plan proceeding (2022 Carbon Plan Order).

The 2024 through 2026 solar procurements should include a total of at least 1,450 MW of SPS, resulting in an incremental increase of 1,100 MW of SPS to the 2022 Carbon Plan.

If neither the incremental 475 MW of standalone batteries nor the 1,100 MW of SPS are procured or selected in resource solicitations in the next CPIRP, the Companies should address how to account for the shortfall.

The Public Staff's modeling also suggests that longer duration battery storage may be economical and necessary to meet the carbon reduction targets. For example, the Public Staff's EnCompass modeling result selects 100 MW of 4-hour standalone storage and 100 MW of 6-hour standalone storage to be placed in service in 2030. The Public Staff recommends that the Companies begin planning for the development and deployment of cost-effective longer duration battery storage.

Q. Please explain each of your recommendations for onshore wind technology.

A. The minimum quantities of onshore wind that should be targeted for development and deployment are 600 MW by 2031, 1,050 MW by 2032, and 1,800 MW by 2033, with a maximum total procurement of 2,500 MW by 2033, with each recommendation being subject to the conditions listed below and in the Public Staff's NTAP.

The final procurement targets should be updated once the Companies are able to develop more accurate cost estimates and to obtain more specific data related to operational characteristics (e.g., wind speeds, output profile, hub heights, annual capacity factors, and capacity contribution to summer and winter peaks) than were available for use in the development of the CPIRP.

As discussed in more detail below, future CPIRP cycles should incorporate cost data and operational characteristics in parallel with early-stage joint development, while enabling a check-and-adjust strategy. More precisely, the Companies should file a report within 12 months of the issuance of the Commission's CPIRP order in this docket. The report should provide a general update for onshore wind development, with updated cost information, updated wind profiles, and a comparison of revised estimates (based upon actual data) of the levelized cost of energy to the projections used in the 2023 EnCompass model.

At least 33% of the minimum target quantities should be located in DEC, barring technological, commercial, or economic issues that make such a procurement impossible. Likewise, no more than 67% of the minimum should be located in DEP. If the maximum amount is selected (i.e., actual costs are lower than current projections or if load growth continues at a faster pace than Duke's P3 Fall Base (FB) projections), the locational ratio should remain the same (33% / 67% ratio) between DEC and DEP. The ratios were based upon detailed review of the Encompass model results and are supported by Exhibits B through D.

To the extent practicable, and for reasons discussed in my testimony, including transmission transfer costs, DEC-located resources should be prioritized over DEP-located assets given the higher load projections in DEC.

Q. Please explain each of your recommendations for combustion turbine technology.

A. First, I recommend that a minimum amount of 849 MW (approximately equivalent to two 425 MW nominal simple cycle combustion turbines (CTs)) in CT resources should be pursued, subject to economic selection of the resource by EnCompass. The Public Staff, however, is still analyzing the impact of the CAA Rule on the planning process and has not yet determined a maximum amount of CT resources to be pursued; the Public Staff also awaits proposals from Duke on how to implement solutions to the CAA Rule.

Due diligence on the impacts of the CAA Rule is required before a definitive determination on the maximum amount of CT resources can be made.

There is also an interrelationship between the development of future combined cycle units (CCs) and CTs as discussed in greater detail below. Should CCs be built in another utility's service area for reasons other than economic buildout, there is a direct impact on the overall selection of CTs. In addition, the Companies' recently filed applications for certificates of public convenience and necessity (CPCNs) for a Roxboro CC[2] and Marshall CTs[3] create more uncertainty around future CT needs.

The Public Staff's proposed NTAP should not be interpreted as limiting the Companies to approximately 849 MW of CTs between now and the next CPIRP. Rather, the Companies should apply for approval of CPCNs as CT need is actually determined. CPCNs for facilities fueled by natural gas will be required to address compliance with the CAA Rule.

Last, the Strategic Energy Risk Valuation Model (SERVM) is a reasonable tool to address system reliability needs that may not be reflected in EnCompass modeling, and SERVM results should be used to determine a minimum capacity target that can be adjusted as needed to maintain or improve system reliability. I request that the Companies complete a SERVM

[2] See Docket Nos. E-2, Sub 1318, and EC-67, Sub 55.

[3] See Docket No. E-7, Sub 1297.

evaluation on at least the Public Staff's PS Base 2034 (PS1F 2034) portfolio, as discussed in more detail later in my testimony, and that the Companies provide the results in their rebuttal testimony in this proceeding. The Public Staff acknowledges that the minimum CT target level may need to be increased based upon the SERVM results, depending upon the assumptions used in the SERVM analysis.

Q. Please explain each of your recommendations for CC technology.

A. I recommend that a minimum amount of approximately 1,359 MW (equivalent to a single 2 x 1 CC unit) in CC resources be pursued, subject to economic selection of the resource by EnCompass.

As stated above, there is an interrelationship between the development of future CCs and CTs. Should CCs be built in another Company's service area not based upon an economic buildout, a cascading event then occurs that directs the selection of future CTs. The Companies' recently proposed CPCN applications for a Roxboro CC and Marshall CTs also create more uncertainty around future CT needs.

Further, a maximum number of CCs to be developed cannot be determined until more review of and due diligence on the CAA Rule is performed. Based upon my current understanding of the CAA Rule and review of Public Staff witness Nader's testimony, CC generation units are subject to more stringent emissions requirements than CTs. Future CC CPCN applications must demonstrate compliance with the CAA Rule before being granted by the Commission.

The Public Staff's proposed NTAP should not be interpreted as limiting the Companies to approximately 1,359 MW of CCs between now and the next CPIRP. Rather, the Companies should apply for approval of CPCNs as CC need is determined.

The Companies must rely upon a glide path, a level of reasonableness, to properly manage the retirement of approximately 8.5 GW of coal generation while maintaining system reliability as other resources are added. The Public Staff's modeling results support the economic selection of a limited number of CCs to aid the retirement of existing coal generation and to serve new load. To date, the Public Staff's modeling has been unable to fully evaluate the impacts of the CAA Rule. Nevertheless, our modeling suggests that it may be more economic to locate CCs in DEC as opposed to DEP.

The Public Staff does not support Duke's proposal to apply for approval of five CPCNs by 2026 for new CC generation plants due to significant concerns about fuel supply, greenhouse gas (GHG) regulations, large economic load materialization in the timeline forecast by the Companies, and an elevated risk of having stranded assets or assets not utilized close to their economic selection point. The continued need for multiple CCs should be reviewed in the 2025 CPIRP.

I recommend that, in future CPIRP filings, the Companies report on the progress of securing firm natural gas supply capacity for the Companies' proposed CC units 3 through 5 (or 6) and provide an analysis of the materialization of large load customers.

Last, I recommend that, to the extent that the Companies make assumptions around including hydrogen as a fuel source in future CPIRPs, either by blending or converting up to or at 100% hydrogen by volume (or equivalent), they include the load requirements necessary to generate the hydrogen in addition to procurement and transportation alternatives for acquiring necessary hydrogen elsewhere. The Companies should discuss the challenges and limitations of accelerating further buildout of non-carbon emitting resources necessary to support the incremental load associated with hydrogen generation.

Q. Please explain each of your recommendations for pumped storage hydroelectric technology.

A. The Public Staff finds the Companies' modeling approach and economic analysis supporting Bad Creek II[4] to be reasonable at this time.

DEC should be required to provide updates on Bad Creek II in the next CPIRP or, if appropriate, before the next CPIRP if DEC determines that the

[4] Bad Creek II is a proposal to expand DEC's existing Bad Creek Pumped Storage hydroelectric facility, located in South Carolina. As proposed, the expansion will approximately double the facility's current capacity of 1,630 MW.

project cannot be completed in the proposed timeline or if estimated costs of this resource increase by 15% or greater from the 2023 CPIRP supplemental filing prior to the next CPIRP. To the extent that the project cannot be completed on time, there is value in determining whether project slippage or delay would materially change the NTAP in this case, and whether future procurement targets should increase or decrease in the interim by providing a revised capacity expansion plan.

Q. Please explain each of your recommendations for small modular reactors (SMR) and other advanced nuclear technologies.[5]

A. Based upon the lower present value revenue requirement (PVRR) associated with the deployment of small modular reactors (SMR), it is reasonable for the Companies to pursue SMR development and deployment in the Carolinas as long as the cost estimates used in EnCompass modeling for the 2023 CPIRP for SMRs remain within a reasonable range.

Based upon current cost estimates, the Public Staff recommends deploying the following *minimum* amount of SMR resources: (1) 300 MW by 2034, (2) 600 MW 2035, and (3) 1,200 MW by 2036.

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[5] At the outset, it is important to note that advanced nuclear technologies as outlined in Duke's CPIRP petition (Appendix J) is comprised of both SMRs and advanced reactors (AR), and I incorporate this framework in my testimony.

Given the long lead time associated with this technology, it is reasonable to provide guidance on a procurement target out to 2036. To the extent it is determined that advanced nuclear can be developed and deployed at a faster rate, the timeline of development activities may be adjusted in future CPIRPs.

The Companies should provide annual updates on their progress and development efforts for SMRs and advanced nuclear technologies which should include, but not be limited to, regulatory developments, impacts to project schedules, and material impacts to cost estimates.

Modeling results demonstrate interrelationships between offshore wind and new advanced nuclear technology deployment, and both technologies have long lead times and higher capital costs. To the extent that the Companies cannot achieve the proposed pace of SMR development, or if the original schedule is found to be untenable, the Companies should plan to substitute nuclear generation with offshore wind, or other economically selected generation.

The Companies should prioritize siting the first three SMRs in DEC service territory based upon modeling results, unless factors arise that would cause a need for deployment in the DEP service area.

Q. Please explain each of your recommendations for offshore wind.

A. Duke should not pursue the procurement of offshore wind, or any resource for that matter, at “all costs” or at “any cost”.

The Public Staff recommends a minimum procurement of a nominal 2,200 MW - 2,400 MW of offshore wind.

In addition, the Public Staff recommends that the Companies accelerate their proposed acquisition request for information (ARFI) schedule and subsequent actions to make reasonable efforts for the first block (between 800 MW – 1100 MW) of offshore wind to be in service between 2034 and 2035, subject to required transmission upgrades.

The Public Staff’s recommendation should not be interpreted as an endorsement of the transfer of ownership of any offshore lease.

An independent evaluator (IE) should be selected as one of the means of evaluating future offshore wind solicitations. To that end, the Commission should open a new docket for the purposes of selecting and defining the role of the IE, thus providing structure, oversight, and transparency to future actions around procurement of offshore wind.

To promote an actionable outcome of the Companies’ proposed ARFI, while balancing the need for developers to provide realistic pricing, a “strike price" should be established prior to the issuance of the ARFI. The strike price would be used to determine whether correctly structured and accurate ARFI proposals are submitted by developers, and when an actionable procurement target will commence. The strike price should also account for, among other things, targeted quantity, cost, timing, risks, and executability. The strike price should also allow for pricing consideration (1) if bid prices are higher than the target procurement amount, such that the volume may be adjusted downward or eliminated; and (2) if the prices are lower, the volume may be adjusted upward while factoring in expected transmission costs.

To the extent that the Companies wish to proceed with offshore wind development, a further discussion of risk and cost sharing should commence. For example, Dominion Energy has a price ceiling and equivalent risk sharing element between ratepayers and shareholders if costs exceed the price ceiling. The risk sharing does not have to be resolved in this docket given the Companies' proposal includes a limited request for relief and the Companies are not seeking a CPCN (or equivalent) at this time. However, the new docket, as discussed above in reference to the IE recommendation for future offshore wind activities identified in the NTAP, would be a reasonable venue for discussion and determination of any future risk sharing.

Q. Please explain why your recommendations for certain technologies in the Public Staff's proposed NTAP are more prescriptive than others.

A. My testimony, along with the review, findings, and recommendations of other Public Staff witnesses in this case, identifies the need for additional ratepayer protections in regard to deployment of certain technologies versus others, particularly for offshore wind.

Generation resources that were mostly unchanged among multiple portfolios and sensitivities provide a high level of confidence in their need and less divergence of outcomes. For example, solar and SPS are repeatedly selected across various portfolios, whereas offshore wind had a greater divergence in its selection timing and total quantity. Our proposed NTAP provides directional guidance for various program enhancements and addresses increasing storage deployment. In addition, 1,100 MW of solar is much less than 1,100 MW of offshore wind on a $/kW, or even total cost, basis. In addition, offshore wind requires additional ratepayer protections given the uncertain costs, timeline, and feasibility, particularly given the recent challenges experienced by other projects in the northeast United States. Further, offshore wind takes longer to deploy than solar (or SPS) and requires significantly more logistical planning. My comparison of solar to wind is analogous to a comparison of CTs to advanced nuclear.

An additional reason for more prescriptive recommendations is to track when and where new generation assets are being added and to ensure they are added to a given utility service area based upon need. Later in my testimony, I discuss the total amount of energy generated within the DEP service area that is being transferred to the DEC service area.

Finally, the cumulative review of multiple portfolios and sensitivities has demonstrated that the selection of offshore wind is the most ductile (influenced) of all resources. Given the current risk and uncertainty of the offshore wind resource, more ratepayer protections are necessary at the same time that the Companies seek regulatory certainty for their near-term actions.

In aggregate, I believe that the prescriptive nature of my recommendations would help ensure reliability for the Companies' customers, provide clearer planning directions, seek a least cost solution at reasonable terms for the Companies and their customers, and work toward the carbon compliance targets of HB 951.

III. CAPITAL COSTS OF NATURAL GAS PLANT ADDITIONS

Q. Did you review the capital costs associated with the construction of new natural gas plants in Duke's initial and supplemental CPIRP?

A. Yes.

Q. What findings or areas of concern do you wish to bring to the Commission's attention?

A. Although most of my concerns regarding capital costs for new natural gas plants were resolved in the Companies' supplemental CPIRP filing, I would like to bring several remaining items to the Commission's attention. The Companies updated and increased the capital costs of future natural gas generation resources in their update to reflect more recent pricing information given the trends with inflation and resources.

At this time, I find the Companies' proposed capital costs for both CTs and CCs reasonable for planning purposes, though, as described in further detail below, these proposed capital costs do not account for the uncertainty of future carbon reduction regulations nor uncertain long-term impacts to asset lives due to operational complexities. I do not, however, have the same level of comfort with the proposed total capital costs and ongoing expense requirements for hydrogen or carbon capture and sequestration. Further analysis beyond this CPIRP proceeding is necessary before incurring substantial costs pursuing either technology.

Q. Please expand upon your concerns regarding the impact on capital costs of potential future carbon reduction regulation.

A. While the content or timing of future regulations is never certain, the EPA's recent release of its CAA Rule is a present reality as discussed in more detail in Public Staff witness Nader's testimony in this proceeding.

Nevertheless, due to the CAA Rule's recent release, a level of uncertainty surrounds its nuances and implementation impact on the Companies.

I was not able to estimate the capital costs and the amount of carbon reduction achieved by using hydrogen in combustion turbines or by installing carbon capture and sequestration. Although new natural gas general plants are currently economically selected resources in Encompass models, the uncertainties associated with the final CAA Rule elevate risks and create concerns about the economic longevity of these plants.

The challenge here is that DEC and DEP are planning to retire an aging and near end-of-life coal generation fleet when the development of long lead-time generation resources does not coincide with the Companies' retirement of the coal assets. There should be a degree of flexibility in the planning process, so the long lead-time generation resources continue to be economically selected in the respective utility service areas. The economic selection of natural gas resources in this CPIRP should allow the Companies some degree of certainty in the planning process, including retirement of over 8 GW of coal generation, while also maintaining a reliable electric grid and achieving interim carbon compliance.

Q. How should the Commission consider the uncertainties of carbon reduction regulation and the impact on future gas generation plants?

A. Modeling sensitivities or model variants are a reasonable method to account for cost and technology uncertainty while providing for a "least regrets" outcome. As an initial point, the magnitude of coal generation that is being retired cannot be overstated when considering the results of multiple modeling portfolios. My testimony shows the degree of unit ramping requirements[6] (i.e., stops and starts of spinning reserve machines) as well as operating reliability limits[7] that system operators require to ensure a reliable grid during all hours.

Q. Please describe in more detail how you accounted for hydrogen and carbon capture and sequestration uncertainty.

A. I discuss the two technologies separately given the differences between these two methods of carbon reduction.

Hydrogen

Public Staff witnesses Michna and Nader also discuss elements of uncertainty and concern relating to hydrogen, and I echo their findings and conclusions.

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[6] Ramping represents the rate at which a generation unit can be safely turned off or on, and how quickly the generation resource can produce incremental energy/capacity to the grid. Some generation units can respond faster than others from both an off to on state and how quickly in MW/minute (or MW/hour) they can inject power onto the grid.

[7] Operating reliability limits account for the balance of real time, physical limitations of the electrical system. System operators continuously attempt to keep generation and load in balance. When generation exceeds load, over-voltage or over-frequency occurs; too little generation can lead to low voltage and under-frequency. Either condition, if not addressed in short order, can lead to load shed and equipment damage. Physical limitations of power transfer capability can result in an imperfect electrical system amid changing conditions. At certain points in time, to maintain the balance of generation to load and ensure reliability, system operators are required to plan for contingency events, such as an unplanned outage of a power plant or even loss of a transmission line.

As stated above, I cannot fully quantify the capital requirements for hydrogen generation and or hydrogen technology requirements, due in part to uncertainty around the variance or volume of hydrogen blending coupled with uncertainty around the cost of energy to generate the hydrogen.

An EPA report lists the hydrogen capability of CTs from original equipment manufacturers (OEM).[8] Advanced class turbines are typically designated by a letter beginning with "G" or beyond. For example, GE's HA-Class is an advanced class turbine given the "H" designation in the Turbine Model/Type designation table shown below. The same designation for advanced class turbines can be found for both Siemens and Mitsubishi manufacturers and are the "G" and "J" classes respectively.

[8] https://www.epa.gov/system/files/documents/2023-05/TSD%20-%20Hydrogen%20in%20Combustion%20Turbine%20EGUs.pdf, May 2023

Manufacturer	Turbine Model/Type	Current Hydrogen Capability[1]	Future Hydrogen Capability[2]
GE Gas Power			
	Aeroderivative	85%	100%
	B/E-Class	100%	
	F-Class	100%	
	HA-Class	50%	100%
Siemens Energy			
	SGT5/6-9000HL	50%	
	SGT5/6-8000H	30%	
	SGT-700	75%	
	SGT-750	40%	
Mitsubishi Heavy Industries			
	M501GAC	30%	100%
	M501JAC	30%	100%
	M701JAC	30%	100%

[1] The actual % by volume hydrogen levels may vary based on combustion turbine model, combustion model, combustion system, and overall fuel consumption. Turbines currently co-firing greater than 30% hydrogen by volume typically utilize wet, low-emission (WLE) or diffusion flame combustors.
[2] Manufacturers are developing DLN combustor modifications for several turbine models that will allow for increased hydrogen firing while limiting emissions of NO_x. These include pre-planned small modification or retrofits kits for certain models to increase their levels of hydrogen combustion.

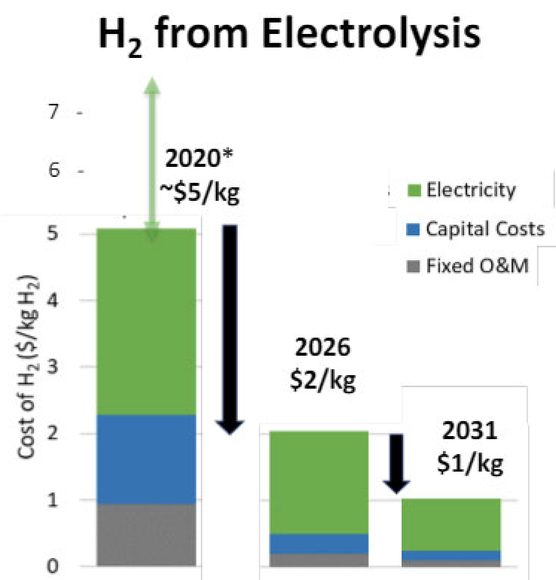
My takeaway from the EPA report is that Duke's proposed advanced class turbines are not capable of firing with 100% hydrogen by volume at this time. It is very important that the Commission understand the co-firing percentages listed in the above table and that the discussion about hydrogen capable CTs is specific to the CT and not necessarily reflective of the impacts to the balance of plant.

OEMs appear to be planning for higher percentages of hydrogen blending, and I expect that technological innovation will occur. My larger concerns, presently, are around the sourcing or supply of hydrogen and the cost of the electrical load requirement of hydrogen production. Onsite hydrogen generation will act essentially like a parasitic load to the generation plant, meaning it will consume a significant portion of the energy generated by the plant to produce the hydrogen for the plant. Even if not parasitic load to a specific plant, hydrogen generation will be a general load on the overall electrical system and, therefore, require additional system generation to account for (1) the electrical load to generate hydrogen, and (2) the onsite or nearby hydrogen storage that will need to be built. In other words, the production of hydrogen and the storage of hydrogen in containers (or equivalent) will require electricity. Either generation will have to be built for these purposes, take place during periods when excess carbon-free generation is available, or use curtailable generation (i.e., solar curtailments during low-load periods).

One method to generate onsite hydrogen would be the utilization of a commercially available (i.e., a mature technology) polymer electrolyte membrane (PEM) electrolyzer.[9] Based upon U.S. Department of Energy (DOE) white papers, PEM costs could range from $2 per kilogram (/kg) to $7/kg of hydrogen produced, which appears to be largely dependent upon

[9]https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis#:~:text=In%20a%20polymer%20electrolyte%20membrane,the%20PEM%20to%20the%20cathode.

the cost of electricity to support the energy conversion within the PEM apparatus as shown in the light green (top bar) in the figure below.[10, 11, 12]



Carbon Capture and Sequestration

Carbon Capture and Sequestration (CCS) is a process for capturing carbon (CO_2) after thermal combustion but before the carbon is exhausted into the atmosphere. The CCS system would transport and store the CO_2, likely in underground geological areas such as saline formations, coal seams, or oil and natural gas reservoirs.

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[10] https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/19009_h2_production_cost_pem_electrolysis_2019.pdf?Status=Master.

[11] https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/20004-cost-electrolytic-hydrogen-production.pdf?Status=Master.

[12] https://www.energy.gov/eere/fuelcells/articles/doe-hydrogen-program-update-2022-annual-merit-review-and-peer-evaluation.

My rough level estimate, not including ongoing fixed and variable costs, suggests that CCS would add an additional $1 to $2 billion of overnight capital costs to each proposed CC facility. The transport distance (i.e., piping needed to transport the CO_2) and routing of infrastructure would add even more cost. My estimate is based upon a 2023 Pacific Northwest National Labs' news release the U.S. Energy Information Administration's Annual Energy Outlook 2023 report, and Duke's own Generation Unit Summary information.[13,14]

Summary of and Conclusions on Technologies:

CCS and hydrogen generation, blending, and transportation are all areas of uncertainty, should these types of technologies be required for modeling sensitivities for natural gas generation units.

Q. Did DEC propose a hydrogen co-firing demonstration project in its multiyear rate plan (MYRP), filed in Docket No. E-2, Sub 1276?

A. Yes. I provided extensive testimony in that proceeding on the proposed demonstration project, and the project was ultimately removed from DEC's proposed MYRP.

[13] https://www.pnnl.gov/news-media/scientists-unveil-least-costly-carbon-capture-system-date

[14] https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf

Q. What was the hydrogen blending percentage in the MYRP hydrogen demonstration project as proposed?

A. Thirty percent by volume.

Q. Can you provide a hypothetical overnight installed cost for a thirty percent onsite hydrogen blending facility at a new Company-modeled CC based upon DEC's proposed demonstration project?

A. Yes. Hypothetically, and scaled from the DEC proposed MYRP demonstration project, the overnight capital costs would be approximately $3 billion. However, that cost is highly uncertain given the size of the hydrogen generation facility required for a CC project, and further adjustments to the estimate are needed to determine reasonable economies of scale savings. It is also noteworthy that my estimate does not account for the cost of energy to create and then store the hydrogen, ongoing operation and maintenance expenses, or potential tax credits.

Q. Did the Public Staff complete an EnCompass model run to account for the monetary uncertainty of hydrogen or CCS carbon reduction technologies?

A. No. Given that the final CAA Rule was published just weeks prior to filing testimony, a fully vetted EnCompass model run was not completed. Attempting such a model run would be complicated by the need to account for the CapEx (capital expenditures) and other expenses associated with each technology, as well as the load and parasitic elements of each respective technology.

IV. TRANSMISSION TRANSFER RATE

Q. Please summarize what constitutes a transmission transfer within CPIRP modeling.

A. The EnCompass model uses the three Duke Balancing Authority (BAs)[15] to represent the current transmission system. The model simulates connections (interties) between each of the BAs, with maximum seasonal capacity limits, thereby simulating an aggregated transmission system. The transmission interties cannot be modeled for firm capacity transfers to satisfy each Company's reserve margin, as only energy is allowed to flow across the interties in a non-merged utility.

The EnCompass model simulates power flows across each virtual intertie point on an hourly basis, and the maximum power flows across each virtual intertie align with current transmission limitations. However, no tariffed transfer cost is applied to power flows between each BA in the Companies' models.

[15] DEC, DEP East, and DEP West.

Q. Did the Companies materially change their transmission transfer methodology between the 2022 Carbon Plan P1 through P4 portfolios and the 2023 CPIRP portfolios?

A. No.

Q. Did the Public Staff critique how the Companies modeled power flows on the transmission system in their 2022 Carbon Plan?

A. Yes. In the Public Staff's initial comments on the Companies' proposed 2022 Carbon Plan, we recommended that the Companies include a tariffed transfer cost. This tariffed transfer cost acts as a proxy to assign a reasonable monetary value for one utility's use of another utility's transmission system. The transfers of energy in the Carbon Plan were mostly one-sided with DEP transferring significantly more energy to DEC than vice versa. Later in my testimony, I discuss how the overall trends in this CPIRP indicate an increase in the number of transfers from DEP to DEC compared to the 2022 Carbon Plan.

Q. Briefly describe the benefits of including a tariffed transfer cost in the EnCompass model.

A. Inclusion of a transmission tariff transfer cost accounts for the use of another utility's transmission system for importing energy while allowing the model to economically determine in which BA (DEC or DEP service area) a resource should be built. Importantly, Duke's modeling approach results in DEC customers receiving subsidized energy, in that DEP ratepayers pay for the transmission infrastructure associated with moving energy across DEP to DEC.[16]

Utilization of transfer costs effectively requires the model to evaluate whether it is more cost-effective to (1) build generation in BA1 and transport the energy to BA2 or (2) build generation in BA2 where the load is located. Even if building in BA2 appears more costly initially, when the costs to use and maintain a transmission system are taken into account, building in BA2 may be the more economic decision.

Q. Did the Public Staff perform any analysis that includes the tariffed transfer rate? If so, please describe the methodology.

A. Yes. We completed our analysis both with and without a tariffed transfer rate. The methodology used in Public Staff model runs in this CPIRP is identical to our proposal in initial comments in the 2022 Carbon Plan and is reflected in the Companies' supplemental P5 analysis in that proceeding.

This overall methodology uses DEC and DEP's respective FERC-approved Open Access Transmission Tariff (OATT) as a proxy for costs. In this CPIRP, I made one small modification from our 2022 Carbon Plan recommendation. Specifically, for purposes of creating a general proxy for the cost of transmission in this CPIRP, I included the costs associated with

[16] Following the 2012 merger of Duke Energy Corporation (now parent of DEC and DEP) and Progress Energy, Inc., all transmission charges associated with wheeling power between the DEC and DEP balancing areas were eliminated (i.e., de-pancaked).

transmission projects that each Company proposed in their most recent MYRPs. However, my methodology did not account for the additional transmission costs associated with the new economically selected generation identified in each portfolio, so the overall values may be understated. Still, the values represent a general proxy cost to account for transmission costs.

Table 1: Tariffed Transfer Rate

	DEC $/MWH	DEP $/MWH
On-Peak	6.19	8.62
Off-Peak	2.95	4.10

Later in my testimony, I demonstrate that it appears that DEC requires substantial reduced or carbon free energy to help meet system requirements, thus necessitating the transfer of energy from DEP East (where significant carbon-free energy sources are, or likely will be, located) to DEC.

Q. What concerns do you have if the Commission does not consider the transmission transfer rate?

A. I have already discussed one concern: that in the absence of consideration of a transmission transfer rate, DEP ratepayers are subsidizing DEC customers,[17] while DEC customers have lower overall retail rates.

At this time, I also anticipate DEP's transmission costs to grow at a faster rate than DEC's, given the lower siting cost of carbon-free resources in DEP's territory, including possible future deployment of offshore wind. In some of the Public Staff's modeling sensitivities, large amounts of nuclear generation were selected for siting in DEC's territory which, in aggregate, reduced and even eliminated the need for future offshore wind over the 15-year planning horizon. In addition, there are certain economic advantages for siting natural gas generation assets in DEC's service territory compared to DEP in that the DEC service area is more proximate to the Williams Companies' Transco interstate pipeline.

Q. Please summarize the magnitude of energy being transferred between DEP and DEC.

A. Overall, the amount and magnitude of energy transfers in this CPIRP is significantly greater than in the 2022 Carbon Plan.[18] The Companies'

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[17] DEC customers are not compensating DEP customers for use of DEP transmission rate base or for ongoing operations and maintenance costs associated with same.

[18] See Table 7: Key Risk Factors Across Portfolios, Public Staff Initial Comments.

proposed 2023 Carbon Plan P3 FB supplemental filing showed approximately 25% of the total energy generated in the DEP BA being transferred in certain years to serve DEC load, representing a two-fold increase from the values seen in the 2022 Carbon Plan. Based upon EnCompass modeling and post-processing of the Companies' P3 FB plan, energy will be transferred from DEP to DEC at a whopping 96.3% to 90.4% of all hours in the 2030 through 2035 timeframe, and these percentages would remain elevated for multiple other years.[19] To put this in context, for 8,436 hours in a given year, energy will flow from DEP East to DEC if the Commission adopts Duke's P3 FB proposal. No longer are these transfers being driven exclusively by solar generation output as more energy is being transferred in non-daylight hours when solar output in the DEP service area is nonexistent.

Q. How do the projected power flows from DEP to DEC compare to the present, exclusive of the cost of transmission?

A. For the 2022 calendar year, actual total transfers from DEP to DEC were relatively matched with Duke's P3 FB Encompass model results. In 2022, there were approximately 6,265,979 MWh of actual net power flows from DEP to DEC, compared to Duke's P3 FB 2025 modeled year, which predicted 6,953,161 MWh of net power flows. Comparing the total transfers

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[19] The discrete years of 2030 and 2035 were reviewed. Based upon general trends of increasing transfers, it is likely that the power flows in years 2031 through 2034 were similar to the 2030 and 2035 results based upon the generation assets built and load profiles.

modeled in EnCompass to actual total transfers does provide a level of confidence that the modeled results of energy transfers are directionally reasonable. However, the total energy transfers from DEP East to DEC grow at a rapid rate after 2025 through the interim carbon compliance date.

Q. Have you identified any factors that may cause this increase in energy transfers from DEP East to DEC?

A. To determine the contributing factors of the increase in energy transfers, I took into consideration the number and types of resources that are pre-existing (i.e., the amount of solar relative to load in DEP East is greater than DEC). For example, the number of transfers from DEP to DEC each hour in a year directly correlates with a solar generation profile shape that has its lowest output during the nighttime hours. Transfers then slowly increase from the morning up to about midday, peak between noon and 2:00 p.m., slowly ramp back down until evening, and then stay at a low level until the next daily cycle. To the extent that a single generation resource continues to grow (i.e., build and interconnect) at the same ratio as present levels in DEC and DEP, and holding load constant, the number of transfers will increase as load in DEP fails to align with the amount of generation added in DEP.

A key factor that contributed to the doubling of energy transfers is, most likely, the updated load forecast. The ratio of the incremental load in the update that was located in DEC was greater than that located in DEP, even when taking the overall DEC/DEP load ratio in consideration.

Another factor is that there are constraints imposed by the Companies on the Encompass model. While some constraints may be reasonable and reflect practical real-world factors that must be taken into consideration, other constraints may not be reasonable.

For example, the Companies restricted the model so that it selected DEP for the first and second years in which a CC could be selected instead of allowing the model to optimally select a resource based upon least cost.

Additional factors that likely contribute to the increase in transfers are that much of the onshore wind, all of the offshore wind, and most solar resources would continue to be developed in DEP East.

Q. How are the Companies addressing the transmission disparity and total energy transfers from DEP to DEC?

A. I am not certain that the Companies have a long-term goal or plan in place to address the current trends of increasing east to west power flows beyond the proposed merger of DEP and DEC. However, there have been incremental steps to address the disparity in the near-term. In the most recent DEP and DEC MYRP rate cases, Docket Nos. E-2, Sub 1300, and E-7, Sub 1276, respectively, the Public Staff and the Companies reached a comprehensive settlement that included a transmission proxy amount to address, in part, the monetary value of DEC using of DEP’s transmission system.[20] If this approach is adopted in future proceedings, it can provide a level of accounting for current power flows between the two utilities, or, if DEC and DEP merge, this proxy becomes moot.

Based upon discovery responses, it appears that the approach settled upon in the general rate cases may be a longer-term solution, as the Companies and the Public Staff are addressing near-term rate disparity concerns arising from the increasing net transfers of energy from DEP to DEC under the Joint Dispatch Agreement (JDA) through the Transmission Cost Allocation Stipulation entered into in those rate cases. The Companies anticipate that achieving a merger of DEC and DEP will resolve longer-term issues around transmission investment cost recovery between the two utilities.[21]

The transmission transfer rate is another tool to assist in evaluating the costs of a generation facility when factoring in the cost of transmission. As I stated previously, it may be more economical to locate a generation asset in one service over another considering the costs to maintain and develop the transmission system, coupled with which utility utilizes the energy. However, if it still proves more cost effective to locate the facility in one utility

[20] The Commission’s approval of this transmission proxy amount in Docket No. E-7, Sub 1276, is currently on appeal before the North Carolina Supreme Court.

[21] Company response to Public Staff Data Request 31-22.

and transfer the energy to the other utility, this transfer rate in the model will do nothing to address transmission subsidization issues.

Q. Is your proposed transmission tariff rate represented in the Public Staff's PVRR calculations and bill impacts?

A. The transmission tariff rate is modeled as a hurdle rate, or a cost which the economic resource portfolio needs to overcome before the transfer takes place. Given that it is a proxy and serves only as a hurdle rate, the overall costs are not represented in the Public Staff's PVRR and bill impact analysis. If the costs were included, DEP's overall rates would be less than what is illustrated in Public Staff witness Williamson's bill impact analysis testimony.

V. NEW NUCLEAR GENERATION

Q. Please provide a summary of the current status of new nuclear development.

A. Since the 2022 Carbon Plan, the status of future deployment of advanced nuclear technologies (SMRs and advanced reactors) is relatively unchanged.

There has been some positive momentum at the Nuclear Regulatory Commission (NRC) with the proposed 10 CFR Part 53 (Part 53) licensing process.[22] Generally, in the United States, the older and traditional commercial nuclear generation fleet was predominantly licensed under 10 CFR Part 50 (Part 50), a “two-step” licensing process. In 1989, the 10 CFR Part 52 (Part 52) licensing process was approved, enabling a degree of flexibility for reactor design and site permitting. Once the Part 53 rule is finalized, perhaps as soon as later this year, more clarity will be provided for future licensing activities that choose to use the Part 53 licensing route. Part 53 will be applicable for new advanced nuclear reactors and is anticipated to provide more flexibility and applicability to a variety of advanced reactor technologies. Part 53 may allow for a faster NRC review process, enabling design surety while bringing new nuclear generation to commercial operation sooner.

Also, since the 2022 Carbon Plan proceeding, Southern Company’s Vogtle Units 3 and 4 have begun commercial operation and have achieved 100% criticality. While these units are not considered advanced nuclear technologies, this achievement demonstrates the completion of new

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[22] For more information on the NRC’s nuclear power plant licensing process, see: https://www.nrc.gov/reading-rm/doc-collections/fact-sheets/licensing-process-fs.html and https://www.nrc.gov/docs/ML0421/ML042120007.pdf . (Last visited May 20, 2024.)

nuclear generation in the United States for the first time since the 1990s and the safety of the overall design.[23]

While the Part 53 update is a positive indicator for future nuclear generation, not everything is positive. NuScale Power Corporation (NuScale)[24] canceled a project in late 2023 with Utah Associated Municipal Power Systems, creating more uncertainty on the immediate future of new nuclear generation. However, it is important to note that factors specific to this project are what likely contributed to its cancelation. The canceled project was essentially subscription based, meaning that it required multiple off takers for its power output. The Companies would most likely own, operate, and utilize all of the power produced by a project similar to the Utah one canceled by NuScale, representing a much different utility model.

Q. What is your opinion on the state of the Companies' proposed activities and pace of future nuclear generation?

A. Overall, the Companies' proposal is reasonable as long as new nuclear development stays on pace with the Companies' modeled SMR schedule. However, in certain modeling portfolios and sensitivities performed by the

[23] The Tennessee Valley Authority (TVA) completed Watts Bar Unit 2 in 2015. Unit 2, along with Watts Bar Unit 1, received a construction permit from the NRC in 1973, but construction on Unit 2 was halted in the 1980s before completion. Construction on Unit 2 resumed in 2007, it received its operating permit in October 2015, and began commercial operation in 2016. Unit 1 achieved commercial operation in 1996.

[24] NuScale is a publicly traded company based in Portland, Oregon that designs and markets SMRs. Its founding was based on research that began in 2000 at Oregon State University and was funded by the DOE.

Public Staff, we noticed on one end of the spectrum that total nuclear deployment had slowed. While on the other end of the spectrum, in the absence of significant amounts of offshore wind, hydrogen, CCS, and CAA Rule certainty, the deployment of new nuclear would need to move at a much faster pace than Duke's proposed schedule in order to maintain system reliability while achieving least-cost planning. I discuss the correlations of technologies and under which scenarios the results converge and diverge later in my testimony.

Q. Did the Companies update any nuclear technology-related information in their supplemental analysis?

A. Yes. Duke provided updated cost information in its supplemental analysis, addressing recent trends in inflation and rising costs of technology implementation. Duke's updated costs generally align with the public information provided in Dominion's recent 2023 Integrated Resource Plan. It is important to note that new nuclear generation is a technology that continues to be selected in both Duke's and the Public Staff's modeling, even when costs are updated.

Duke also updated its timeline to build out concurrent nuclear generation units. Duke's revised timeline appears to enable leveraging further synergies from one generation unit to the next while minimizing the need to transfer resources (equipment and labor) between multiple sites.

The first year of availability for SMRs, as identified in the EnCompass models, aligns with Duke's likely desire to not be the "first mover" on future nuclear generation. There are pros and cons to this approach as discussed in more detail later in my testimony. Should the Commission adopt or approve Duke's proposal, it would help to mitigate the risks associated with being a first mover.

Q. Please expand on the pros and cons of being a first mover with new nuclear generation.

A. Generation III+ nuclear reactors (larger 1,000 MW+ nameplate capacity units) that have been built or are under construction in the United States and Europe have had setbacks. There have been schedule conflicts, final project costs higher than initial estimates, and commercial operation dates later than expected. Nevertheless, multiple factors have contributed to issues that would likely not transfer to SMRs given their overall smaller scale and scope.

A second, third, or fourth mover would be able to learn from the first mover of advanced nuclear generation, or any generation resource for that matter. Lessons learned would come from the areas of design enhancements, project management, material procurement, construction cycles, and generally every action or process involved to bring the unit to commercial operation.

At some point, however, some entity must be the first mover in construction and commercial operation of advanced nuclear technologies; it is just a matter of when and who it will be. To the extent that advanced nuclear technologies are economically selected to maintain system reliability, but the utility delays the deployment of advanced nuclear technologies because it does not want to be first, the delay may come at an increased cost to ratepayers due to the utilization of a different, less economical, generation portfolio. In other words, while delaying future nuclear generation would provide cost and risk certainty, it will contribute to higher overall system costs to the extent that capacity and energy needs are met with a higher cost resource.

In addition, due to the current uncertainty of the Part 53 license, if a utility moves forward under other NRC licensing activities to expedite or accelerate the build schedule (e.g., Part 52), there is a risk of an increase in incremental costs for rework should reactor design change when site and material procurement were occurring concurrently. Stated differently, if license approval or construction activities for advanced nuclear technologies move at a faster pace than Duke's proposed schedule and methodology, there is a possibility of an increase in overall capital costs or project delays, though this possibility is not quantifiable at this time. One must factor in that overall risk with the potential PVRR impacts of accelerating deployment or staying at the current pace.

Q. From your experience and review of the Companies' proposal, do you consider Duke to be balancing the pros and cons you mentioned above.

A. Yes.

Q. What actions can the Commission take to help ensure economic procurement of new nuclear generation for the Carolinas?

A. As previously noted, new nuclear generation is economically selected in both Duke's and the Public Staff's modeled portfolios. Commission approval of the Companies' proposed near-term activities would be an important starting point for the economic procurement of new nuclear generation. Should the Commission find the Companies' load estimates to be reasonable, the near-term activities requested by Duke should be viewed as a minimum, with the possibility of more extensive development activities being required as well.

It is also worth noting again that the magnitude of resources being selected in the current EnCompass models is driven by the significant load growth trends and projects. If the load growth materializes as is currently forecast, and if there are delays in bringing other generation resources online, overall electric system reliability could be negatively impacted.

One option to consider that could lead to greater project certainty would be to evaluate a multiple unit order contract and development cycle. While to some degree a novel concept, it would provide cost surety for multiple units while essentially allowing the costs of the first and/or second units constructed to be socialized in part with subsequent nuclear units. This would provide value to ratepayers by balancing a predicted and repeatable cost for multiple generation units and provide more certainty of the pace at which the generation assets can be brought online. This approach would allow Duke to optimally manage resources over a longer period by enabling the retention of labor resources and maximizing the value of lessons learned. In theory, this approach would also provide more certainty around maintaining system reliability, as the Companies account for increasing intermediate generation resources and evaluation of economic retirement of existing resources.

Q. Are you requesting that Duke move forward with executing contracts today on numerous SMRs?

A. No. My testimony is intended to demonstrate the potential benefits of future nuclear generation when faced with significant load growth and in the midst of a generation fleet that is transitioning to more modern technologies while achieving a significantly lower carbon footprint.

VI. FUEL SUPPLY

Q. Please describe fuel supply and how it pertains to reliability.

A. The Companies' historic, as well as current, aggregated generation portfolio has a diverse mix of generation resources relying upon different fuels: nuclear, natural gas, coal, hydro, solar, etc. Over the last five years, the

DEC fleet has begun to utilize significantly more natural gas for both energy and capacity. DEC's additions of W.S. Lee CC, Lincoln County CT 17, and the dual fuel conversions of Marshall, Belews Creek, and Cliffside are primary contributors to this increased utilization of natural gas.

Thermal generation resources are not subject to the intermittent generation challenges of stand-alone solar and wind energy. Nuclear generation typically operates for anywhere from 18 to 24 months before needing to refuel with replacement fuel bundle assemblies. Coal generation resources operate with a coal pile, or onsite reserve, to absorb the uncertainty of resupply. In general, the Companies' coal generation plants maintain around a 35-day supply of coal if operated at 100% of full nameplate capacity. The shrinking demand for coal use by electric generation resources and railroad scheduling and demand issues are contributors to the ongoing concerns around the sustainability and predictability of coal supply. Natural gas supply in the Carolinas is dependent upon maintaining a supply and demand balance in real-time conditions on the Williams Transco interstate pipeline, as well as with local distribution companies (e.g., PSNC and Piedmont Natural Gas). Should there be more demand than supply, or if supply issues arise similar to those experienced during Winter Storm Elliott with natural gas well heads freezing, the pressure will drop on the natural gas pipelines and natural gas compressor stations will not be able to increase pipeline pressure to maintain operations, leading to natural gas-fired electric generation units being forced offline.

History reveals that a diverse portfolio mix of generation resources has served the Carolinas well by mitigating fuel security risks as the resource mix is complementary and provides for overall system reliability. The value of a fuel diverse portfolio is not captured in the economic selection in EnCompass resource planning, as it is more qualitative than quantitative at this point.

Q. Did both the Companies' and the Public Staff's models economically select new natural gas generation?

A. Yes. Every Public Staff model run selected some quantity of natural gas generation unless the Public Staff prevented (forced) the Encompass model settings to not be able to the select natural gas generation.

Q. Did the Public Staff force natural gas generation into its core model runs in Encompass.

A. No. When natural gas resources were selected in our model runs, it was because they were economically selected in Encompass, including in the Public Staff's CAA Rule sensitivity run.

Q. Does the economic model consider fuel supply risk?

A. No. Post-run evaluation of model results is required to discern potential fuel supply risk factors. However, constraints can be used in the model to account for both execution and fuel supply risks.

Q. Please explain the constraint the Companies included in their proposed model for natural gas supply and whether the constraint addresses fuel supply risk.

A. The Companies made general assumptions on a future firm supply of natural gas for their new CCs and included proxy price adders to account for the monetary cost to provide supply. The Companies allowed the addition of up to six new ~1,360 MW nameplate CCs, each CC utilizing ~250,000 dekatherms of natural gas daily. Public Staff witness Michna discusses this topic in his testimony as well.

Q. Did the Public Staff include any additional natural gas fuel modeling constraints in its modeling?

A. Yes. In reviewing the events that took place during and after Winter Storm Elliott coupled with the capacity and energy coal generation portfolio retirements leading to greater reliance on natural gas, the natural gas system may need some type of buffer to account for acute high demand days.

I support the inclusion in the model of onsite liquefied natural gas (LNG) facilities at certain CC generation sites. This resource will provide an additional buffer, or fuel reserve, of four to five days of supply should there be a disruption to the main pipeline in either typical operations or – more likely – a high stress winter event. In addition, an LNG storage facility could mitigate operational flow orders and monetary penalties for under- or over usage during constrained events on the natural gas system.

Q. Are other utilities planning LNG facilities to support natural gas generation assets?

A. Yes. In its recently filed 2023 IRP, Dominion included a potential LNG facility to support the Brunswick and Greensville CC facilities in Virginia.

Q. Does the Public Staff believe that new LNG storage should be built at each new or existing CC?

A. No. For purposes of modeling and estimating a potential future resource, and to maintain fuel security, a proxy monetary value was included in the Public Staff's modeling runs, as discussed in more detail by Public Staff witness Michna.

Q. Are there additional items of concern or specific topics relating to fuel security and resource modeling that you wish to bring to the Commission's attention?

A. Yes. For fuel security, I have already highlighted the economically driven shift to natural gas dependency to meet new load and system reliability requirements as older, end-of-life, and less economic coal plants are retired. Given the shift in dependency from one fuel source to another, the overall electric system has increased its fuel supply and price-volatility risks.

From a resource modeling standpoint, the Companies' combination of model runs using sensitivities such as high capital costs, high fuel costs, low load, high load, etc., in combination with its base portfolios is a robust and reasonable approach for determining a least regrets plan, while establishing areas to check and adjust in the future.

Q. Please briefly expand on the elements to which you are alluding when you reference "check and adjust."

A. Public Staff witnesses Thomas and Michna have covered this topic in their prefiled testimonies, and I echo their findings. Absent a known reliability issue that must be fixed "today," and all other reasonable actions having been exhausted, there is time to continue the evaluation process in future CPIRPs for purposes of determining whether the continued buildout of natural gas generation plants, or any other technology for that matter, is in the public interest. At this time, the uncertainty around the final CAA Rule is too great to blindly approve billions of dollars in capital plant expenditures for units that may be uneconomically limited in production output, subject to early retirement, and/or that require even greater capital investment to maintain over their expected lives.

Therefore, based upon the Public Staff's modeling results, I do not see a need at this time for Duke to acquire five CPCNs for CCs prior to the next Commission-approved CPIRP.

VII. TRANSMISSION

Q. Did the Public Staff submit a joint public policy request to the Carolinas Transmission Planning Collaborative (CTPC)?

A. Yes. The Public Staff's initial public policy request became a joint request of the Public Staff and other interested parties. I personally submitted the joint public policy request in early 2023. The request focused upon the transmission impacts of the retirement of older generation assets and the integration of new generation for meeting carbon reduction objectives. In addition, I worked with other parties in helping prepare and submit a modified joint public policy request. Any descriptions or highlights I provide are my own, and I am not attempting to represent the perspectives of the joint participants.

Q. Please highlight the areas the Public Staff was trying to identify in the request.

A. The Public Staff had, and still has, concerns about the increase in power flows from DEP East to DEC (east to west) and the ability to sustain the maximum allowable transfers, as noted earlier in my testimony. The Public Staff is concerned as well about the time it would take to build a larger scale transmission line to alleviate a future overload. My observation of east-to-west power flows is heightened in the current CPIRP, which shows increased loading on the interties between DEC and DEP.

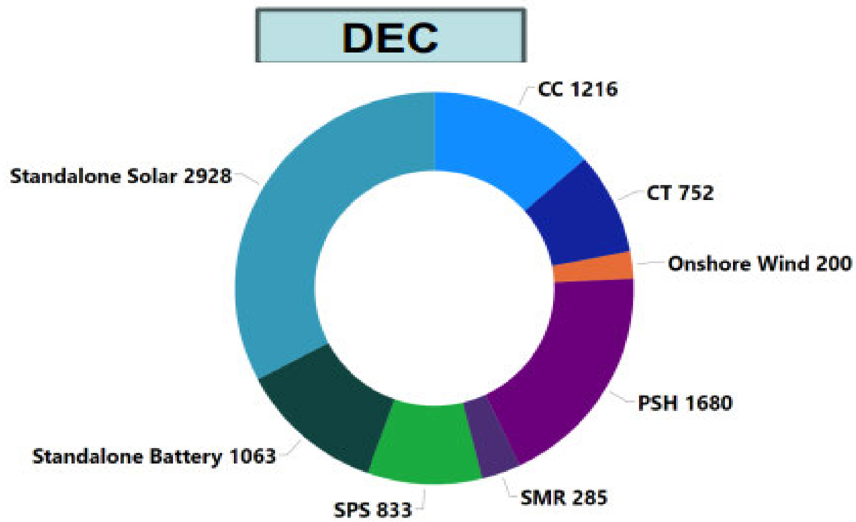
A larger scale transmission project could take a decade or longer to plan and build, depending upon the scale of the upgrade required. In addition, a larger scale transmission project may require the proposed implementation of resource deployment in each Duke service area to be reassessed to ensure system reliability. One or more generation projects can create a hypothetical tipping point leading to a large-scale transmission upgrade. In such event, transmission cost estimates would be updated and assigned to the particular generation project(s). Then, modeling constraints can be adjusted, if necessary, to account for the physical limits of the transmission system. The transmission system is a core function of resource planning. Transmission planning ensures long-term reliability and should be a factor for the Commission to consider when it takes into account the plain language of HB 951 that references maintaining or improving system reliability.

The 2023 public policy request was approximately a yearlong process, requiring the CTPC to perform a detailed power-flow analysis and identify transmission reliability concerns. The CTPC staff provided general updates throughout the process.

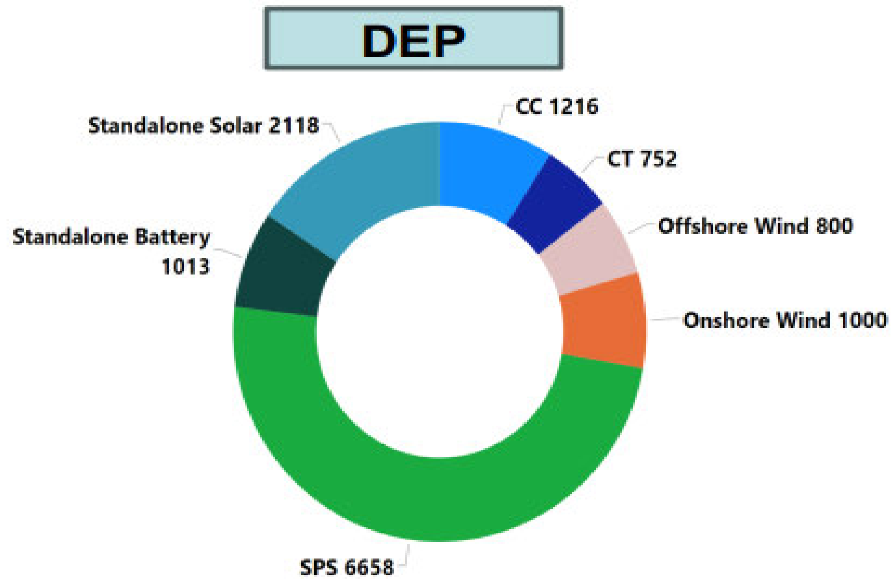
The following resources were included in the public policy request, as informed by the 2022 Carbon Plan:

2033 S 2033/2034 W	Coal Retirements	Standalone Solar	SPS[2]	Onshore Wind	Standalone Battery	CC	CT	Offshore Wind	SMR	PSH
DEC	-3050	2900	850	200	1063	1216	752	0	285	1680
DEP	-3175	2100	6650	1000	1013	1216	752	800	0	0

For DEC, the following resources were included in the public policy study:



For DEP, the following resources were included in the public policy study:



The portfolio mix was an all of the above (every type of resource) approach to model transmission power flows. Simplifying assumptions had to be made on specific generation resources, given the still uncertain interconnection points for over 12.5 GW of aggregate resource additions.

The final 2023 public policy report was finalized and released publicly on May 17, 2024.[25] Based upon my review of the preliminary results of the study and the final report, while the primary 500 kV system running between DEC and DEP does not trigger a major component overload, certain areas of interest are identified. Specifically, the study results identify

[25] http://www.nctpc.org/nctpc/document/REF/2024-05-17/NCTPC_2023_Public_Policy_Study_Draft%20Report%2005172024.pdf

approximately 800 to 1,100 miles of impacted 44 kV, 100 kV, 115 kV, and 230 kV transmission lines having major component overloads, approximately 60% of which are located in DEC territory. The final report also indicates that just the major component overloads would cost around $2.6B within DEC and DEP to rectify. The preliminary results identified impacts to Dominion Energy South Carolina and Santee Cooper and identified the overloading of six utility interties, notably in the southern parts of both DEC and DEP East service areas.[26]

It is important to note that my understanding of the intent of the public policy study process is to identify major equipment overloads. Should the hypothetical generation portfolio be implemented, additional contingency analysis would need to be conducted. Based upon follow-up discussions with the CTPC, additional contingency analysis caused overloads on multiple sections of the DEC and DEP 500 kV systems and additional 230 kV and 100 kV impacts were also noted. The previous cost estimate of $2.6B does not account for the additional contingency analysis and the cost and time required to address the contingency overloads is uncertain at this time.

[26] The six overloads are as follows: two overloads at DEP East to DEC, two overloads at DEP East to Yadkin, one overload at DEC to DESC, and one overload at DEC to SETH (though SETH" is not formally identified in the preliminary findings.)

Q. How does the portfolio mix represented in the 2023 public policy study align with the Companies' updated supplemental analysis or even the Public Staff's model runs?

A. The overall portfolio mix is similar between the public policy request results and Duke's updated supplemental analysis. There are more resources in terms of nameplate capacity that are selected in this CPIRP compared to the 2023 public policy study request results over the next 15 years, noting that the 2023 public policy request was a general proxy for a hypothetical resource mix within a ten-year period with both SMR and offshore wind deployment to account for resources that were right outside of the ten-year window.

Table 1: Changes in Studies and Portfolios

	Solar (MW)	Onshore Wind (MW)	Offshore Wind (MW)	Battery Storage (MW)	Natural Gas (MW)	SMR (MW)	PSH (MW)
2023 CTPC Public Policy Study	12,500	1,200	800	2,076	3,936	285	1,680
Public Staff PS1F variations	~18,000 -26,000	~2,000	0 to 4,400	~6,000 – 16,000	4,000-13,000	600-2700	2,030
Duke P3 FB 2035 Compliance	~18,000	2,250	2,400	~6,000	~9,000	~2,100	2,030

Q. Did the Public Staff submit a 2024 public policy study request to the CTPC?

A. Yes, but the proposal was submitted prior to finalizing our 2024 CPIRP Public Staff portfolios. The CTPC will have to consider multiple stakeholder requests in the current CTPC cycle, and it is not certain whether the Public Staff's 2024 proposal will be selected and/or modified to match other parties' submittals.

Q. When will you be able to submit a new CTPC study to evaluate the Public Staff's proposed modeling portfolios from this CPIRP evaluation?

A. It will most likely be as early as January or February of 2025 when the Public Staff considers submitting a new CTPC study, after the Commission issues its order in this CPIRP proceeding.

Q. Are there any additional items that you would like the Commission to consider in regard to long-term transmission planning and the public policy process?

A. Yes, there are a couple of items that I recommend the Commission consider as it reaches its decision in this CPIRP proceeding.

First, CTPC public policy studies utilize hypothetical and generalized data to simulate areas of potential interconnections. Stated differently, the CTPC or the public policy submitter has limited certainty on where future interconnections will occur. With that in mind, the results of the public policy request should be considered as directional, not absolute, guidance.

Second, the current approach of identifying a capital expansion plan and then waiting a year or two after the initial submission of the CPIRP to request a transmission study is fundamentally broken and not sustainable given the dynamic expansion of load and resources contemplated in this proceeding, particularly considering the long lead times for resources like offshore wind and nuclear. The current process of resource modeling (i.e., EnCompass resource modeling, not transmission power flow modeling) incorporates general cost proxies, which is a positive. While utility system planners and modelers can include constraints in models to simulate operational and execution risk, evaluation of the transmission system needed to implement a proposed portfolio is currently left out of the process. However, that evaluation should be incorporated as the next step in the evolution of resource planning.

Q. Do you have any examples of why it is important to perform a transmission study complementary to a resource portfolio?

A. Yes. One example is illustrated in Table 1: Changes in Studies and Portfolios, shown above. The amount of solar as well as other resources proposed in the Companies' resource plans is significant, as is the 2,400 MW of offshore wind being selected in the Companies' supplemental analysis.

Q. Did the Public Staff perform a transmission study complementary to its proposed portfolios?

A. No, and I acknowledge that as a shortcoming of our proposed portfolios given the differences between Duke's recommended resources and ours. The divergence of certain generation assets is too significant to have certainty as to their impacts on the transmission system. At present, however, the Public Staff does not have the staffing, knowledge, or software resources to complete transmission modeling.

Q. Based upon your experience, have you identified transmission concerns with your proposed portfolios?

A. Yes.

First, the most obvious concern is the selection of 4,400 MW of offshore wind. The Public Staff EnCompass model runs did include a general proxy price for future transmission. The general proxy price for transmission is based upon a composite of Duke's estimates, as discussed in more detail in Public Staff witness Lawrence's testimony. For context, if the EnCompass model selected approximately 4,400 MW of offshore wind, the general proxy for transmission results in about $3B in transmission upgrades, a significant cost to include. The transmission proxy price for offshore wind is meant to emulate the potential for two discrete and separate interconnections and subsequent 500 kV/230 kV upgrades. I do not know the feasibility of bringing a nominal 2,200 MW of offshore wind to the grid from an intertie more southerly than at New Bern and connecting to the main backbone 500 kV of the primary electrical system that is more than a hundred miles away, would most likely be routed through wetlands and swamps, and would impact numerous landowners. I believe it is appropriate to acknowledge the challenges to engineer and site transmission upgrades needed to onshore and interconnect 4,400 MW of new offshore wind over a span of a few years, let alone plan the greenfield construction of large scale 230kV or 500kV transmission lines.

Another concern is the significant amount of battery storage to be interconnected and an evaluation of battery storage charging and discharging. Large amounts of battery storage localized in discrete areas of the transmission system without coordinated charging may not result in excess generation causing overloads, but in unanticipated load that creates the need for upgrades. Stated differently, if the deployment of batteries is not properly accounted for, there may be additional upgrades not envisioned today, or upgrades could be overbuilt due to the lack of charging coordination on a larger bulk system basis. Further, the need to plan and coordinate the bulk electric system to accommodate large-scale battery deployment is not factored into the Public Staff's resource production cost modeling at this time.

Q. Please summarize your understanding of the Companies' concept of Red Zone Enhancement Projects (RZEP).

A. Duke's proposed RZEP projects in this case build off the prior 2022 Carbon Plan RZEP (i.e., RZEP 1.0). In my view, the RZEP concept is meant to address the long lead times associated with certain transmission projects, balance the need for system energy and capacity from cost-effective generation resources, and adapt to a changing energy landscape. The success of solar deployment in the DEC area, and more so in the DEP service area, has contributed to excess generation in certain areas and overloads on certain transmission lines.

Q. List the RZEP projects in Duke's proposed initial and first supplemental CPIRP plans in this proceeding?

A. Duke proposes the following RZEP projects:

Project	Service Area (Owner)
Broadway 100 kV	DEC
Bush River Transformers	DEC
Champion 100 kV	DEC
Clayton Industrial	DEP
Lilesville-Oakboro 230 kV	DEP

Duke estimates the overall capital cost for these projects to be approximately $200M.

Q. Have you identified any concerns with the way the Companies determined the project need for the proposed initial and first supplemental RZEP projects?

A. Yes. My largest primary concern is that the majority of proposed projects appear to be reactionary instead of holistic.

While it is reasonable that Duke's proposed projects are likely intermediate steps to accommodate additional generation in a timely manner, there has been no formal study or cost analysis to demonstrate that these proposed upgrades are least cost or leverage the most system benefits for all ratepayers.

The projects located in DEC are centric on addressing a topological (design) issue with DEC's legacy 100 kV transmission system. Specifically, the legacy 100 kV system has limits on how much power it can carry over longer distances in a radial configuration with a lower voltage level. My investigation in this case requested analysis and studies for alternative projects and/or alternative solutions. I specifically asked about the Companies' proposed natural gas plant to be located in South Carolina and whether transmission synergies could be leveraged with other transmission projects in the southwest portion of DEC's service territory, and even interties into DEP. No detailed alternative analysis was completed by the Companies, or at least none was provided in response to my request. Alternative analysis and studies would help inform longer-term solutions and identify whether the short-term actions proposed by Duke are truly least cost and reasonable.

My concerns around the DEP projects are slightly different. Both of the DEP RZEP projects are likely needed, given the continued interest of resource solicitation cluster market participants and other future generation resources such as standalone batteries to locate facilities in this area. Earlier in my testimony, I discussed the increasing quantities of east-to-west power flows occurring between DEP and DEC. The Lilesville-Oakboro project has potential to further increase the allowable power flows from DEP to DEC, as the project is at an intertie point between the two utilities. However, as shown in the Companies' filed CPIRP petition, Appendix L, Table L-7, Note 3, this project excludes the costs of the DEC portion of the Oakboro 230 kV substation. I request that the Companies discuss this portion of the project in rebuttal in this proceeding. If the as-proposed DEP-only portion of the project were completed, it is unclear if an increase in the amount of power flows from one service area to another (i.e., DEP to DEC or vice versa) would occur and if so, by how much.

Q. Did you investigate whether any reliability benefits would be created from Duke's proposed initial and first supplemental RZEP projects?

A. Yes. The Companies provided a cost benefit analysis for each of the proposed projects based upon reliability benefits. The DEC projects scored lowest, with the lowest value cost ratio of four (Champion 100 kV line), and the DEP projects scored highest, with the highest project score of 34 (Clayton Industrial). A score of four in this instance indicates that the benefits of the project are four times higher than the costs of the project. However, because future transmission upgrades will most likely not be like-for-like with the existing system, given technology improvements and changing load/generation, these scores may be overly optimistic and should be used for directional purposes rather than considered absolute. While the intent of the score is directional, the actual score can overstate the benefits as reliability improvements are already going to occur if and when the legacy line is upgraded to today's standards.

Q. Are the proposed initial and first supplemental RZEP projects reliability driven?

A. No. Based upon discovery responses from the Companies, no overloads are projected on these segments of the transmission system based upon current load projections. The proposed RZEP 2.0 projects appear to be driven primarily by interconnections of new solar and battery-generating resources.

Q. Did the Companies use the updated load forecast, as detailed in their supplemental filing, for evaluating the load impacts on the transmission system with the proposed initial and first supplemental RZEP projects?

A. No.

Q. What are your conclusions regarding the Companies' proposed initial and first supplemental RZEP upgrades?

A. First, the NCUC is not required to approve transmission projects in order for them to advance through the CTPC process. CTPC working groups have the ability to reach their own decisions as to whether the proposed projects should be a part of the overall transmission plan. In addition, while the Commission may be able to direct the Companies to pursue a transmission project in another state or acknowledge a benefit, siting and permitting authority ultimately rests with regulatory bodies in that state. This reality highlights the importance of having a multi-state transmission planning collaborative, such as the CTPC.

Second, the RZEP projects are not resolving a currently identified reliability issue. To the extent that known reliability issues were occurring or if accelerated deployment of a project would circumvent an already planned project to address a known or anticipated reliability concern, a different conclusion could be reached on the reasonableness of a proactive project. The only project that I view as a potential near-term reliability project is Lilesville-Oakboro, given the magnitude of power flow increases across the DEP to DEC interties but even there, no currently known overloads are occurring. However, as noted above, it is unclear whether completion of this project would increase DEP-to-DEC power flows given the limited information provided in the initial filing.

Third, the Companies did not evaluate alternative projects. The Companies should evaluate larger scale transmission projects that would accommodate multiple technology resources. The Companies also did not present their proposals as a least cost option. Given the different outcomes of both Duke's and the Public Staff's portfolios, larger and more holistic transmission planning is required. For example, an evaluation needs to be completed to determine what project(s) need to be completed to leverage synergies from multi-technology sources and/or would enable bringing thousands of megawatts of resources online and/or would provide a longer-term solution to the east-to-west power flow concerns that are likely to occur under the Companies' current proposals. Also, these longer-term solutions would likely need to be completed in the SERTP given larger-scale impacts to the broader southeast transmission grid, which ties back in part to my earlier point that these decisions should be made within a multi-state transmission collaborative.

Fourth, the Companies have not demonstrated that, in the absence of a proactive buildout of these upgrades, the upgrades could not be funded by cost causers, even if it is a Duke resource which causes the need for the upgrade. While the Companies have used DISIS cluster studies to inform and provide locational guidance on likely upgrades, that does not mean those who cause the upgrades cannot fund the upgrades, or that those potential projects will be materially harmed by the transmission construction schedule. The proposed projects are listed to take about four years to complete, not a decade.

Fifth, the Companies' desire for the NCUC to approve the RZEP projects in advance is creating ratepayer risk from cost assignment and ratemaking perspectives. Should the Commission "approve" these projects on a policy basis, there is the risk North Carolina retail customers will be assigned costs in future rate cases that are traditionally and historically assigned to all jurisdictions.

Q. In your opinion, if the Companies were to proactively build the proposed initial and first supplemental RZEP projects, would there be more certainty towards achieving the interim 70% reduction in carbon as prescribed in HB 951?

A. First, noting that HB 951 has language on maintaining or improving system reliability while achieving interim compliance, the answer to the question is yes and no. Proactively building out transmission upgrades for generation assets that are likely to interconnect would remove some potential for interconnection delays while also enabling an easier path to interim compliance. On the other hand, the proposed RZEP projects are relatively minor in scale compared to a large, hypothetical greenfield project, which would require more time to complete.

The proposed RZEP projects have construction schedules of approximately four years, noting that the Companies already have a host of other transmission projects proposed in their recently approved MYRPs. The Companies' estimated build time for these projects do not appear to materially impact the 2030 or later interim carbon reduction compliance.

One additional item to address is that of ratepayer equity. If transmission upgrades are built and the costs are assigned to DEP ratepayers to provide energy benefits to DEC ratepayers, DEP ratepayers will be unfairly burdened, or in some cases continue to be burdened, with those transmission costs.

Q. Which initial and first supplemental RZEP projects do you recommend that the Commission direct Duke to pursue?

A. I do not recommend that the Commission directly approve any of the proposed projects in this proceeding for the multitude of reasons I have discussed. Duke is not prevented from moving forward with these projects via the traditional transmission process.

Q. Would you consider any of Duke's initial and first supplemental RZEP projects to be reasonable to pursue given the information you obtained through discovery and/or of which you have general knowledge?

A. Given the pros and cons discussed earlier in my testimony, I believe the Clayton Industrial-Selma and Lilesville-Oakboro projects appear to be reasonable.

The Industrial-Selma line appears to have a high likelihood of need given the power flow trends on the DEP transmission system, project scoring information provided by Duke, and the benefits to DEP's customer base. Publicly available information exists about certain industrial customer(s) expanding in the general area of the proposed transmission line, demonstrating that load continues to grow in the localized area.

The Lilesville-Oakboro project appears to be the first step to address the magnitude of the east-to-west power flows, providing the ability to move more power between the DEC and DEP systems, while enabling more economic energy transfers to minimize overall production costs for both sets of utility ratepayers. The project would also allow wholesale customers to move additional energy across the DEC and DEP systems. However, it is unclear if the full benefits of the energy transfer will be enabled as the DEC Oakboro portion of the upgrade was omitted from the Companies' proposal.

Notwithstanding the equity issues raised previously, I acknowledge that the Industrial-Selma and Lilesville-Oakboro projects, with the DEC portion of the upgrade, are generally reasonable transmission projects to pursue through the traditional transmission process but not all of the project costs are known.

Q. Did you investigate the proposed supplemental RZEP 2.0 project listed in the Supplemental testimony of Companies' witness Roberts?

A. No. There was insufficient time to review and incorporate this approximate $130 million dollar project into testimony given the timing of its filing in this proceeding.

VIII. PORTFOLIO ANALYSIS

Q. Did the Public Staff conduct and complete multiple EnCompass model runs or portfolios to evaluate future system needs for DEC and DEP?

A. Yes. Public Staff witness Thomas explains in detail each of the Public Staff's portfolios, including how they were modeled and the resource selection differences.

Q. Please summarize the items you considered in reviewing each of the Public Staff's model runs.

A. At a high level, I relied upon my professional experience to consider the general feasibility of completing each portfolio in the proposed timeframe, while balancing the realities of (1) real-world construction schedule challenges, (2) the present state of technology (i.e., commercial availability), (3) the disposition of excess energy, (4) ramping constraints to match generation with load, (5) transmission requirements, (6) stranded asset risks, and (7) overall PVRR values. While some modeling sensitivities were found not to be executable for multiple reasons, the sensitivity runs stressed the bounds of interconnection abilities and construction schedules.

The sensitivity stress results illustrate relative cost increases, and in some cases decreases, while identifying that offshore wind appears in most cases to be the resource most varying in terms of deployment decisions. My testimony demonstrates the boundaries of potential plans and the balancing of an "all of the above" generation fleet to meet system capacity and energy needs, while striving to maintain or improve system reliability.

Q. What should the Commission's takeaways be from the Public Staff's multiple model runs?

A. It is important to note that the results of my synopsis are subject to the accuracy of the load forecast the Companies provided, along with the fact that any complex modeling endeavor requires a degree of subjectivity.

- Generally, most model results have a similar (fairly tight) PVRR impact, but how each model run achieves those results can vary significantly.
- Some model results are for illustrative purposes and are not likely achievable given real world implementation constraints.
- The most economical, least cost model runs appear to favor faster nuclear development than Duke has allowed in its model runs.
- Accelerated nuclear deployment has a tendency to slow, and potentially eliminate, the need for offshore wind through 2038 (15-year planning horizon).

- DEC's model results require extensive amounts of energy and resources to be built in DEP to serve DEC load; allowing the model to have the freedom to economically locate resources results in more generation assets being built in DEC to serve DEC load is reasonable.

- The impacts and long-term risks of the recently published final CAA Rule are not definitive at this time.

- A "least regrets" approach of evaluating all portfolios shows that the Companies will most likely need to accelerate their proposed plans for long lead time development activities for multiple technologies unless the interim compliance date is further delayed.

- Absent incorporation of battery storage, there appears to be a diminishing value for solar energy. For a continued growth of solar energy deployment, battery storage is needed to shift energy and capacity to other hours of the day.

- Each of our modeling runs show significant challenges in meeting the 2030 and 2032 interim compliance year and some cases even 2034 or beyond. Stated differently, absent very aggressive actions by the utilities, inclusive of demand side management, as well as load reduction from new and existing load (customers), interim compliance in 2030 or 2032 is not reasonably achievable and the impacts of the CAA may cause challenges to achieve 2034 interim compliance.

- If a 40% annual capacity factor cap is applied to new natural gas units as part of CAA Rule compliance, 2034 compliance may be unachievable, regardless of the physical location of the natural gas units.
- Directionally, the Public Staff's model results are relatively close to the Companies' 2033 and 2035 interim compliance year results, with some minor deviations in the total MW procurement/ownership of resources; those deviations, however, have material impacts on what actions must be directed by the Commission for the CPIRP.
- Clear guidance from the Commission on a target interim compliance date would add clarity to the NTAP.

Q. Has the Public Staff compiled the results of its multiple capacity expansion model portfolios?

A. Yes. The compiled results show the total cumulative MW additions for three discrete years: 2029, 2033, and 2038 of the 15-year planning horizon. The intent of selecting these particular years is to identify and illustrate the incremental changes over five-year time periods, while aligning the actions that should be taken prior to 2029 and identifying actions that could be postponed.

Exhibit 2 is a combined listing of future capacity additions for DEC and DEP. Exhibit 2 does not represent a combined utility, rather, Exhibit 2 shows the summed asset additions of DEC and DEP's capacity expansion plans. There is, however, a distinct sensitivity within Exhibit 2 that modeled a combined utility scenario where capacity could be shared between DEC and DEP. Exhibit 3 illustrates DEC-located resources and Exhibit 4 illustrates DEP-located resources.

Q. Please expand upon what you meant by, "actions that should be taken prior to 2029"?

A. If the Commission determines that 2,200 MW (or 2,400 MW in Duke's model runs) of offshore wind is needed by 2033 (or sooner), one must consider the time it will take to bring the resource online. Offshore wind is presumed to take 8 to 10 years to develop, perhaps longer depending on the size of the total facility and transmission requirements. The Commission will issue its order on the CPIRP later this year, leaving approximately 8 years from issuance to January 1, 2033.

Another example would be the amount of solar that needs to be procured. The Commission must determine a reasonable amount of solar for the Companies to procure from the issuance of its order in this proceeding until the next Carbon Plan. The Commission's target amount will inform the market to start the development pipeline for these projects.

This will also provide utilities adequate time to prepare for the development, design, procurement, construction, and testing of these long lead time resources and to maintain the reliability of the grid.

Q. Please clarify how you believe the Commission should determine which actions could be postponed.

A. Based upon the model results, it depends on which portfolio, or group of portfolios, is selected. The interim compliance year is a *major driver*, as well as the ability of the Companies to implement any action or group of actions, both of which should inform the Commission's ultimate order in this CPIRP proceeding.

One example is the number of natural gas CPCNs the Companies must seek to obtain for plants that will be constructed and commercially operational eight to ten years from now. It is too premature to make a determination of need for that many natural gas CPCNS at this time because there is sufficient time to check and adjust in future proceedings.

New Nuclear

Q. Please discuss the results of your analysis of SMR impacts across multiple portfolios.

A. The SMR (i.e., new nuclear deployment) modeling results are unique because the results are dependent upon (1) the first year of availability and (2) how many units can be built in any given period. A large-scale buildout combined with an aggressive deployment schedule would impact the size of (and even cancel some) long lead resources, thus creating other unintended risks.

One unintended risk associated with SMRs if costs increase or commercial operation is delayed, is that there would be limited time to pivot to an alternative resource such as offshore wind. Of course, there is risk that offshore wind leases may default back to BOEM if no development activities begin after a certain point in time, and absent market signals for either private or utility investment, it is unlikely that offshore wind development activities would continue.

Figure 1 below shows the results of the SMR capacity (MW) selected across the multiple portfolios as listed in Exhibit 2. For context, a typical SMR is approximately 300 MW, so 1,800 MW of SMRs would be equivalent to six individual SMRs units.

Figure 1: Nuclear Capacity

Duke Energy Carolinas and Duke Energy Progress System Capacity							
	SMR			PVRR			
Portfolio	2029	2033	2038	2029	2033	2038	2050
PS1F 2030 No CC High Grid Edge	-	-	1,800	$ 31,954	$ 55,236	$ 84,623	$ 155,973
PS1F 2032	-	-	600	$ 28,996	$ 56,225	$ 92,268	$ 169,764
PS1F 2034	-	-	2,100	$ 29,616	$ 52,090	$ 80,857	$ 150,785
PS1F 2035	-	-	2,100	$ 29,677	$ 49,876	$ 77,838	$ 149,836
PS1F 2034 Limit OffSW	-	-	1,500	$ 29,616	$ 49,032	$ 79,861	$ 153,039
PS1F 2034 No Tx Tfr Rate	-	-	1,800	$ -	$ -	$ -	$ -
PS1F 2034 No Tx Tfr Limit OffSW	-	-	1,800	$ 29,616	$ 49,032	$ 79,861	$ 153,039
PS1F 2034 Revised Low Load	-	-	1,500	$ -	$ -	$ -	$ -
PS1F 2034 Limit OnSW	-	-	2,100	$ -	$ -	$ -	$ -
PS1F 2034 Accel SMR	-	900	2,700	$ 29,616	$ 49,795	$ 76,073	$ 148,133
PS1F 2034 Force 2029 DEP CC	-	-	1,800	$ -	$ -	$ -	$ -
PS1F 2034 Shared Capacity	-	-	1,800	$ 29,589	$ 51,998	$ 80,532	$ 150,501
PS1F 2034 High Gas Cost	-	-	1,800	$ -	$ -	$ -	$ -
PS1F 2034 NoEIR	-	-	2,100	$ 29,840	$ 52,327	$ 81,216	$ 151,103
PS1F 2034 EPA 40%CC Limit	-	1,200	2,700	$ 29,730	$ 50,448	$ 77,134	$ 149,282
PS1F 2034 Low Battery Avail	-	-	1,800	$ -	$ -	$ -	$ -
PS1F 2034 NG Cap to 4 CC	-	-	1,800	$ -	$ -	$ -	$ -
PS1F 2034 SC CC	-	-	1,800	$ 29,741	$ 49,687	$ 77,702	$ 146,556
PS1F_2034_2035OSW	-	-	1,500	$ -	$ -	$ -	$ -
PS3F_2037_Force DEP CC, 2035 OffSW, EPA 40% CF	-	-	2,100	$ 29,823	$ 49,788	$ 78,698	$ 154,343
D P2 FB 2033	-	-	2,100	$ 29,931	$ 52,085	$ 80,962	$ 154,916
D P3 FB 2035	-	-	2,100	$ 29,694	$ 51,122	$ 77,877	$ 148,966
Least Regrets	-	-	600	$ 28,996	$ 49,032	$ 76,073	$ 146,556
Median	-	-	1,800	$ 29,616	$ 49,737	$ 77,770	$ 149,124
Upper Bound	-	1,200	2,700	$ 31,954	$ 56,225	$ 92,268	$ 169,764

Based upon the Public Staff's modeling, and comparing it to the Companies' portfolios, the least regrets approach is to build approximately 600 MW of new nuclear in the Carolinas, preferably sited in the DEC balancing area. The median amount of new nuclear would be 1,800 MW by 2038, notably, with the first deployments in the DEC balancing area, followed by DEP.

The upper bound of new nuclear would be a deployment of 1,200 MW by 2033 and 2,700 MW by 2038. The upper bound would require a near concurrent buildout of new nuclear resources in both DEC and DEP in 2033 and 2034.[27]

The Public Staff Accelerated SMR portfolio did not instantaneously build an SMR in the first year of availability (2032), but rather delayed initial deployment until 2033.

One of the Public Staff's EPA sensitivity models selected two SMRs in 2032, the earliest year the resource could be selected. We enabled the model to allow an accelerated buildout of future advanced nuclear technologies for this sensitivity.

Q. Please identify any relationships with PVRR increases or decreases across varying levels of SMR deployment.

A. It is important to remember that multiple factors contribute to the calculation of the PVRR. However, the results are as follows:

- The highest PVRR in both 2038 and 2050 has the lowest SMR deployment.
- The lowest PVRR in 2038 had the greatest SMR deployment.
- Delaying deployment of any SMRs showed a general trend of overall higher PVRRs through 2038.

[27] The upper bound would necessitate 600 MW and 300 MW build in DEC and DEP, respectively, for 2033, followed by an additional 600 MW built in both DEC and DEP for 2034.

- Without considering other factors that impact the overall PVRR calculation, accelerated and high deployment of SMRs appear to be "least cost".

Q. Please identify risk factors with the deployment of SMRs.

A. The ultimate deployment cost of SMRs is a risk factor. The overall PVRR results and trends highlight that if actual costs materially increase above the cost curves and the cost estimates used in modeling, then indicative PVRR trends may be erroneous such that the conclusion of high SMR deployment being least cost would be erroneous as well.

The current state of the NRC Part 52 license and a future Part 53 license, coupled with a limited number of approved reactor designs, prevents a high degree of certainty around the ability to deploy SMRs in an accelerated fashion, including the ability to sustain deployment of multiple units in a single year, at least in the near-term.

SMRs are a carbon free generation resource, enabling both interim and long-term HB 951 2050 compliance. Sustained or even accelerated deployment of either SMRs or future advanced reactors can help resolve challenges for both interim compliance and net zero goals, demonstrating a positive impact on nuclear development in the Carolinas.

Still, SMRs are not as flexible in ramping and energy shifting as are other proposed advanced reactors. Over selection of SMRs earlier in the planning process limits the ability to economically selected advanced reactors in the

2040 period. The occurrence of higher solar penetration without recommended large-scale battery deployment would likely contribute to nuclear cycling (i.e., “turning down” or more likely “turning off” SMR output), leading to higher overall system costs. Proposed advanced reactors have the added benefit and ability to store energy for use during future, non-daylight hours and complement a dynamic grid. While SMRs may not be as flexible as future advanced reactors may be, they will be a valuable asset for the overall grid, providing system inertia and helping to address the potential impacts of intermittent generation or sustained days of low wind or low solar output.

Establishing a minimum target for SMR reactor development and deployment will enable the Companies to negotiate a procurement strategy and gain multiple benefits for ratepayers. These benefits range from certainty of when generation assets can be brought online (reliability), leveraging of synergies to reduce overall costs (monetary), mitigation of large-scale natural gas infrastructure and asset buildout given declining capacity factor curves for these resources (reduce stranded asset risk), and progress toward both interim and long-term carbon compliance while achieving least-cost planning goals (reduction in carbon).

Q. Based upon your findings, does the Companies' proposed Near-Term Action Plan and request for relief support your observations and modeling results.

A. Generally, yes. The Companies' proposed NTAP and request for relief for SMR deployment appears to be the absolute minimum action required for future SMR deployment in DEC. To the extent that Duke moves faster with SMR deployment, it would likely increase additional risks that cannot be fully analyzed at this time. Should the Commission determine that an even faster and increased level of SMR deployment is needed, the Companies should provide an updated schedule of activities and cost updates, along with indicative pricing from Engineering, Procurement, and Construction Contracts (EPCs) and vendors, in order to inform future least regrets CPIRP modeling.

Q. Are there any additional SMR-related items you would like to bring to the Commission's attention?

A. Yes. In summary, future SMRs are a foundational building block for the electrical grid of tomorrow. Based upon the numerous factors listed in my testimony, the Companies should move forward with *evaluating* an accelerated pace of SMR deployment and buildout in the near-term. Multiple model results showed similar results of nearly 2 GW of future SMR deployment by 2038. A faster pace of sustained nuclear deployment may be optimal, but can be addressed in the next Carbon Plan, once the CAA Rule impacts are more fully evaluated and defined.

Combined Cycle Generation

Q. Please discuss the results of your analysis of CC impacts across multiple portfolios.

A. As an initial observation, if EnCompass is allowed to freely select the location of future CCs, the first CCs are selected for deployment in the DEC service area. As has been stated previously, Duke limited the ability of the model to choose between DEC and DEP for 2029 and 2030. Only when the Public Staff limited the availability to build the first CC to DEP, was the CC selected for DEP. The DEC balancing area needs both energy and capacity in larger quantities than does DEP, in part because more of the large-load growth is occurring in DEC.

Second, in all but one scenario (one in which the model was not allowed to select CCs), future CCs were always built, and with few deviations across all portfolios they were selected throughout the 2029 to 2034 time period, after which their selection ceased.

There is a strong positive correlation with CCs built in the earlier years of the model and the timing of coal generation unit retirements. It is clear that these CCs serve as capacity and energy resources, with the units operating at near 80 percent annual capacity factors in the first few years of commercial operation before decreasing over time. As stated earlier in my testimony, the Companies plan to retire over 8.5 GW of nameplate coal generation capacity coupled with a large load increase. Because capacity as well as energy is needed, added to the fact that nuclear and wind resources take more time to develop and bring online, natural gas CCs are the only viable option over the next 10 years or so.

Listed below in Figure 2 are the results of CC selection across multiple portfolios, as listed in Exhibit 2. For context, a typical modeled CC unit is approximately 1,359 MW, so 4,077 MW of CC capacity would be equivalent to three units, and 8,155 MW would be 6 units.

Figure 2: Combined Cycle Capacity

Duke Energy Carolinas and Duke Energy Progress System Capacity							
	Combined Cycle			PVRR			
Portfolio	2029	2033	2038	2029	2033	2038	2050
PS1F 2030 No CC High Grid Edge	-	-	-	$ 31,954	$ 55,236	$ 84,623	$ 155,973
PS1F 2032	1,359	8,155	8,155	$ 28,996	$ 56,225	$ 92,268	$ 169,764
PS1F 2034	1,359	4,077	6,796	$ 29,616	$ 52,090	$ 80,857	$ 150,785
PS1F 2035	1,359	6,795	8,155	$ 29,677	$ 49,876	$ 77,838	$ 149,836
PS1F 2034 Limit OffSW	1,359	5,436	8,155	$ 29,616	$ 49,032	$ 79,861	$ 153,039
PS1F 2034 No Tx Tfr Rate	1,359	4,077	5,436	$ -	$ -	$ -	$ -
PS1F 2034 No Tx Tfr Limit OffSW	1,359	5,436	8,155	$ 29,616	$ 49,032	$ 79,861	$ 153,039
PS1F 2034 Revised Low Load	1,359	4,077	6,796	$ -	$ -	$ -	$ -
PS1F 2034 Limit OnSW	1,359	4,077	6,795	$ -	$ -	$ -	$ -
PS1F 2034 Accel SMR	1,359	5,436	5,436	$ 29,616	$ 49,795	$ 76,073	$ 148,133
PS1F 2034 Force 2029 DEP CC	1,359	4,077	6,796	$ -	$ -	$ -	$ -
PS1F 2034 Shared Capacity	1,359	4,077	5,436	$ 29,589	$ 51,998	$ 80,532	$ 150,501
PS1F 2034 High Gas Cost	1,359	5,436	6,796	$ -	$ -	$ -	$ -
PS1F 2034 NoEIR	1,359	4,077	6,795	$ 29,840	$ 52,327	$ 81,216	$ 151,103
PS1F 2034 EPA 40%CC Limit	1,359	4,077	5,436	$ 29,730	$ 50,448	$ 77,134	$ 149,282
PS1F 2034 Low Battery Avail	1,359	4,077	6,796	$ -	$ -	$ -	$ -
PS1F 2034 NG Cap to 4 CC	1,359	4,077	5,436	$ -	$ -	$ -	$ -
PS1F 2034 SC CC	1,359	5,436	8,155	$ 29,741	$ 49,687	$ 77,702	$ 146,556
PS1F_2034_2035OSW	1,359	8,155	8,155	$ -	$ -	$ -	$ -
PS3F_2037_Force DEP CC, 2035 OffSW, EPA 40% CF	1,359	8,155	8,155	$ 29,823	$ 49,788	$ 78,698	$ 154,343
D P2 FB 2033	1,359	5,436	5,436	$ 29,931	$ 52,085	$ 80,962	$ 154,916
D P3 FB 2035	1,359	6,796	6,796	$ 29,694	$ 51,122	$ 77,877	$ 148,966
Least Regrets	-	-	-	$ 28,996	$ 49,032	$ 76,073	$ 146,556
Median	1,359	4,757	6,796	$ 29,616	$ 49,737	$ 77,770	$ 149,124
Upper Bound	1,359	8,155	8,155	$ 31,954	$ 56,225	$ 92,268	$ 169,764

Setting aside the one portfolio that did not allow for the selection of any CCs, new natural gas generation was selected in the first year of availability in *all* model runs, noting that unit location changes based upon modeling inputs and parameters.

The median capacity of future units built, however, started to deviate across the portfolios by 2033, and the deviations continued into 2038.

The upper bound selection of 8,155 MW (the equivalent of six CCs) in Figure 2 above is intriguing. My takeaway from these results of the upper bound suggests that if higher certainty of interim compliance is the goal, more natural gas would be built sooner rather than later, even though that seems counterintuitive and introduces other risk factors. However, upon closer evaluation of the annual production characteristics and factors for the unit cost of energy delta ($/MWh) between natural gas and coal, when displaced by more cost-efficient natural gas plants, coal generation output is driven to near zero very quickly due to natural gas CC generation producing significantly less CO_2 per MWh than coal.

Q. Please identify any relationships with PVRR increases or decreases across varying levels of CC deployment.

A. Overall, CCs are a resource common to multiple portfolios. The absence of CCs in a future energy and capacity mix results in the second highest PVRR result of all portfolios.

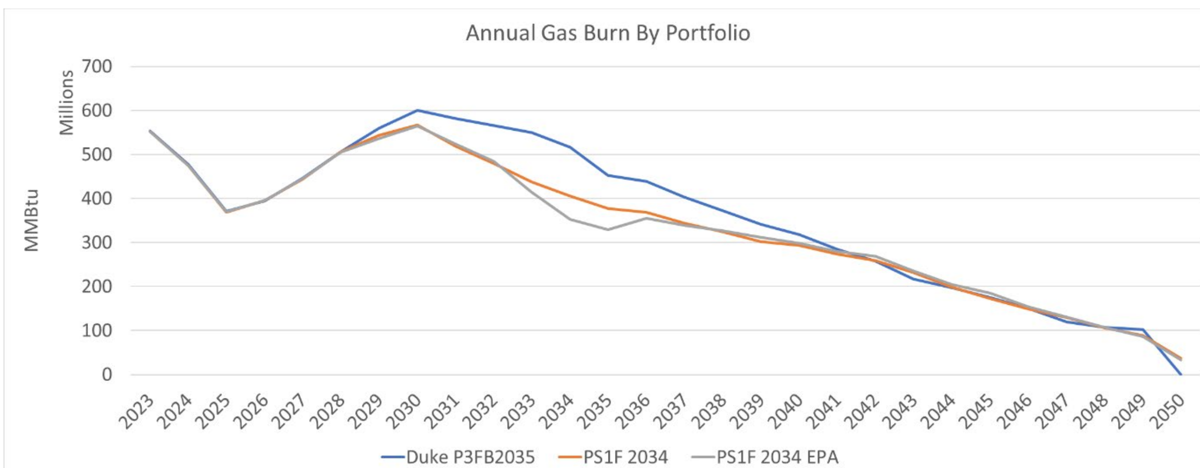
Q. Please identify risk factors for CCs.

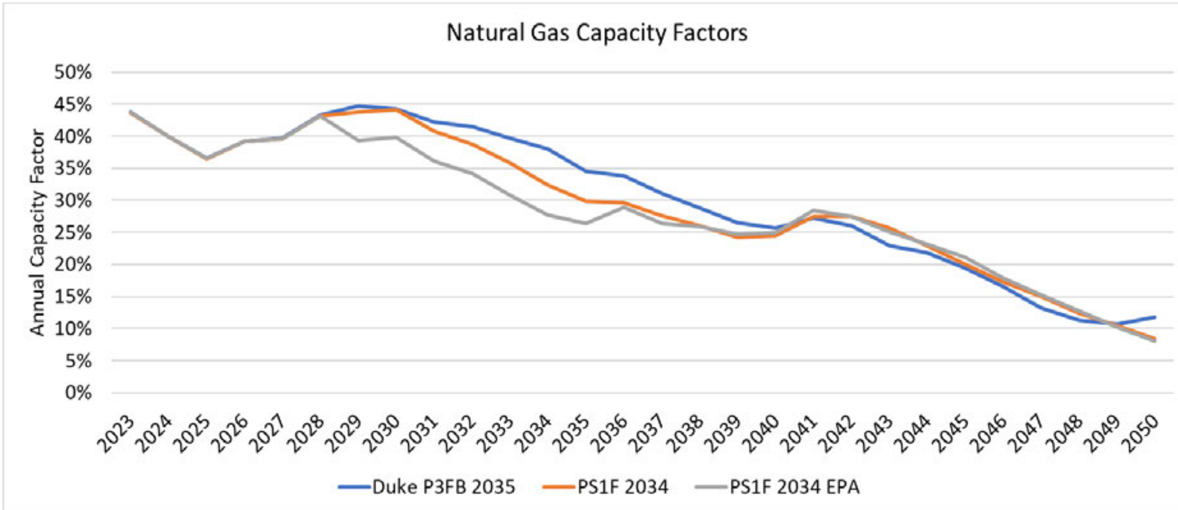
A. The modeling results show both the positive and negative risk factors, which I discuss below.

A buildout of CCs allows for more surety for near-term retirement of the aging, near end of life, less reliable, and higher cost coal units. Transitioning the entire coal generation fleet to retirement has taken years of planning and management by the Companies. I find replacing coal plants with economically selected natural gas assets to be a reasonable approach to achieve early carbon reduction and grid reliability, so as long as the resources are built in the utility service area that requires the energy and capacity and if one factors in the cost of the natural gas pipeline.

The future price of natural gas is both a positive and negative risk to ratepayers. Given the efficiency of CCs, and setting aside the potential impacts of the final CAA Rule, along with low variable O&M costs due to unit design characteristics, the overall total $/MWh cost to serve customers using CC is a benefit, so as long as natural gas prices remain at their currently estimated levels. As the Commission is aware, large increases in natural gas prices can cause large impacts to annual fuel costs, creating cascading issues for ratepayers due to both under recoveries and increases to prospective fuel factors. However, if natural gas prices decrease, the resulting decreased cost of energy is a benefit to all ratepayers.

The modeling results shown above will result in an expansion of the Companies' natural gas fleets, but at the expense of a more resource-diverse portfolio. A resource-diverse portfolio is a qualitative hedge to account for price, fuel supply, and technology uncertainty. Also, increasing the amount of total natural gas burned will compound the risks of future natural gas pricing. Shown below is a graph of the change over time in the total amount of natural gas consumption (MMBTU) for all natural gas usage (simple cycle CTs and CCs) for both DEC and DEP. The following graph shows fleet average capacity factors change over time, the data for which is taken from three different model runs:





The volume of natural gas utilized by the Companies for electric generation, coupled with historically volatile fuel prices, creates a dynamic that can cause large, single year impacts to customers as has been seen in recent years. In sum, the larger amount of natural gas usage correlates to a higher risk of annual fuel rider over- and under recoveries, which is compounded by a reduction in technology availability (i.e., retirement of coal) and fuel diversity.

Q. Based upon your findings, does the Companies' proposed Near-Term Action Plan support your observations and modeling results?

A. Partially yes, but mostly no. The transition from coal to natural gas CC technology is being driven by economic factors and the need for cleaner energy sources. CCs are known for their higher efficiency and lower greenhouse gas emissions compared to traditional coal plants. However, the final CAA Rule's impact on the energy sector remains uncertain, potentially affecting the long-term viability of CC generation as a bridge technology to carbon free resources.

The previous concerns raised by myself and Public Staff witness Michna regarding five proposed CC projects as part of the Companies NTAP highlight significant issues, including the aggressive timeline for the development of these units and the associated natural gas transmission infrastructure. Beyond the risks associated with future CC development, there are more strategic planning issues, including the consideration of alternative sites for the second CC to be built and the need to plan for which resource(s) are used for the future DISIS process for interconnection planning. Moreover, the lack of a firm fuel supply for three of the proposed CC units underscores the need for a more robust and secure fuel strategy before seeking CPCNs for all five CC units before the Commission's next CPIRP order. In totality, these concerns point to the need for a careful review and potential re-evaluation of each proposed CC project's feasibility and impact on the overall system.[28]

As noted earlier, as the energy sector grapples with balancing load growth and sustainability, the integration of high load factor customers could accelerate the need for future generation assets, including the potential for

[28] I acknowledge that the lack of fuel supply (firm transportation) was a similar challenge noted by the Public Staff in the 2022 Carbon Plan proceeding, and that DEC was able to negotiate with Williams Transco in the open season to procure additional capacity.

natural gas CCs. Thus, it is reasonable for the Companies to maintain flexibility in their strategies to adapt to dynamic market conditions and regulatory environments.

Q. Are there any additional items regarding CCs that you would like to bring to the Commission's attention?

A. Yes. The recent CAA Rule presents significant implications for utility resources in the Carolinas, highlighting the need for careful consideration of technology implementation and its economic viability. The current increased probability of new CCs operating at annual capacity factors at approximately one-half of their historical performance, alongside the financial burden of carbon reduction technologies, could lead to increased operational costs and reduced dependable capacity. Furthermore, the risk of new natural gas plants as stranded assets underscores the importance of evaluating the longevity and economic efficiency of these investments. Lastly, the energy transfers occurring, and expected to increase, from DEP to DEC raises questions of equity for DEP ratepayers, suggesting a need for a more thorough examination in rate case settings, CPCN proceedings, and annual fuel rider filings.

Simple Cycle Combined Turbines

Q. Please discuss your analysis of the impact of CTs across multiple portfolios.

A. CTs are selected by the model across all portfolios. Based upon modeling results, it appears that the earlier the compliance date, the greater the capacity of CTs needed. A decision to locate multiple new CCs in the DEP balancing area also contributes to more CTs being built.

Figure 3 below lists the results of the CT selection across multiple portfolios, as shown in Exhibit 1. For context, a typical CT has an approximate 425 MW nameplate rating, so 849 MW / 845 MW of CTs would be equivalent to 2 CT units, similar to the configuration filed in the DEC Marshall CPCN filing (Docket No. E-7, Sub 1297), and 2119 MW / 2123 MW of CTs represents 4 units.

Figure 3: Simple Cycle Combustion Turbine Capacity

Duke Energy Carolinas and Duke Energy Progress System Capacity							
	Combustion Turbine			PVRR			
Portfolio	2029	2033	2038	2029	2033	2038	2050
PS1F 2030 No CC High Grid Edge	1,698	3,393	3,393	$ 31,954	$ 55,236	$ 84,623	$ 155,973
PS1F 2032	2,508	4,628	4,628	$ 28,996	$ 56,225	$ 92,268	$ 169,764
PS1F 2034	849	1,269	1,269	$ 29,616	$ 52,090	$ 80,857	$ 150,785
PS1F 2035	1,273	1,269	1,269	$ 29,677	$ 49,876	$ 77,838	$ 149,836
PS1F 2034 Limit OffSW	849	845	845	$ 29,616	$ 49,032	$ 79,861	$ 153,039
PS1F 2034 No Tx Tfr Rate	849	1,269	1,269	$ -	$ -	$ -	$ -
PS1F 2034 No Tx Tfr Limit OffSW	849	845	845	$ 29,616	$ 49,032	$ 79,861	$ 153,039
PS1F 2034 Revised Low Load	424	420	420	$ -	$ -	$ -	$ -
PS1F 2034 Limit OnSW	849	845	845	$ -	$ -	$ -	$ -
PS1F 2034 Accel SMR	849	845	845	$ 29,616	$ 49,795	$ 76,073	$ 148,133
PS1F 2034 Force 2029 DEP CC	1,273	1,694	1,694	$ -	$ -	$ -	$ -
PS1F 2034 Shared Capacity	849	845	845	$ 29,589	$ 51,998	$ 80,532	$ 150,501
PS1F 2034 High Gas Cost	1,273	1,269	1,269	$ -	$ -	$ -	$ -
PS1F 2034 NoEIR	1,273	1,269	1,269	$ 29,840	$ 52,327	$ 81,216	$ 151,103
PS1F 2034 EPA 40%CC Limit	1,698	1,694	1,694	$ 29,730	$ 50,448	$ 77,134	$ 149,282
PS1F 2034 Low Battery Avail	1,273	1,269	1,269	$ -	$ -	$ -	$ -
PS1F 2034 NG Cap to 4 CC	849	1,269	1,269	$ -	$ -	$ -	$ -
PS1F 2034 SC CC	1,698	1,694	1,694	$ 29,741	$ 49,687	$ 77,702	$ 146,556
PS1F_2034_2035OSW	849	845	845	$ -	$ -	$ -	$ -
PS3F_2037_Force DEP CC, 2035 OffSW, EPA 40% CF	1,273	1,694	3,393	$ 29,823	$ 49,788	$ 78,698	$ 154,343
D P2 FB 2033	2,123	2,119	2,119	$ 29,931	$ 52,085	$ 80,962	$ 154,916
D P3 FB 2035	1,273	2,119	2,119	$ 29,694	$ 51,122	$ 77,877	$ 148,966
Least Regrets	424	420	420	$ 28,996	$ 49,032	$ 76,073	$ 146,556
Median	1,273	1,269	1,269	$ 29,616	$ 49,737	$ 77,770	$ 149,124
Upper Bound	2,508	4,628	4,628	$ 31,954	$ 56,225	$ 92,268	$ 169,764

The least regrets evaluation selected approximately 424 MW of CTs.[29]

The median has greater quantities than the least regrets amount, but the year-over-year change stayed static across all three periods, with approximately 1269 MW selected.

The upper bound has the most divergence across the portfolios. The selection of more CTs above the median appears to be impacted by two key factors: the location of CCs and the interim compliance year.

[29] There is no material difference in 849 MW versus 845 MW, as the same number of units is selected.

Q. Please identify any relationships with PVRR increases or decreases across varying levels of CT deployment.

A. My observations are similar to my CC testimony above in terms of impacts of CT deployment on PVRRs, as CTs are a core component of *all* resource plans.

Q. Please identify risk factors for CTs.

A. The incorporation of CTs into utility modeling and planning is essential given the limitations of the EnCompass model. The SERVM software offers a more comprehensive portfolio analysis than EnCompass because it can assess the impacts of a broader range of weather conditions and load variations on individual portfolios, which is crucial for evaluating and ensuring system reliability under unusual circumstances. However, it is important to recognize that CTs, which pose a lower risk than CCs in scenarios with lower CC adoption rates, are a less efficient generation technology than CCs on a per-unit-of-energy basis. This inefficiency is due to the loss of energy from the exhaust gases of the combustion process. Unlike CCs which can extract energy from the exhaust gases without consuming additional fuel, CTs result in higher carbon intensity and higher production costs. These considerations are factored into the EnCompass model. Under the CAA Rule, opting for CTs over CCs could result in increased carbon emissions and production costs unless mitigation measures such as hydrogen blending or carbon capture are incorporated.

Q. Based upon your findings, does the Companies' proposed Near-Term Action Plan support your observations and modeling results?

A. The analysis of the NTAP for CT technology is a complex issue given the implications on future energy planning. The need for new CC plants, the potential overestimation of future CT capacity, and the pace of transitioning away from coal generation must all be considered. The uncertainty surrounding future load growth and the location of generation assets further complicates the decision-making process. As with CCs, the EPA's CAA Rule introduces another layer of complexity, emphasizing the importance of evaluating the environmental impact of different energy portfolios.

Q. Are there any additional items regarding CTs that you would like to bring to the Commission's attention?

A. The strategic placement of CTs is critical to the development of future power generation infrastructure. The decision to approve or disapprove a CPCN for a CT can significantly influence the planning and location of these facilities. CTs are crucial for providing spinning reserves, ancillary services, and the flexibility needed for system operators to manage real-time events such as resource intermittency and emergencies. While production cost modeling offers valuable insights, it may not fully capture the additional benefits CTs offer in terms of operational responsiveness to fluctuating grid conditions.

Solar PV

Q. Please discuss the results of your analysis of solar PV impacts across multiple portfolios.

A. Solar PV generation resources are economically selected across all portfolios.

The amount of selected solar has increased from the prior Carbon Plan, driven in part by the increased load projections.

Figure 4 below lists the modeling results of solar PV selection across multiple portfolios, as found in Exhibit 2. For context, a typical solar plant is assumed to be approximately 75 MW, so 3,000 MW of solar is the equivalent of approximately 40 solar facilities and 20,000 MW of solar is the equivalent of 266 solar facilities.

Figure 4: Solar Capacity

Duke Energy Carolinas and Duke Energy Progress System Capacity							
	Total Solar			PVRR			
Portfolio	2029	2033	2038	2029	2033	2038	2050
PS1F 2030 No CC High Grid Edge	8,550	21,375	25,762	$ 31,954	$ 55,236	$ 84,623	$ 155,973
PS1F 2032	3,750	12,750	21,937	$ 28,996	$ 56,225	$ 92,268	$ 169,764
PS1F 2034	2,700	11,700	18,112	$ 29,616	$ 52,090	$ 80,857	$ 150,785
PS1F 2035	2,700	11,700	19,912	$ 29,677	$ 49,876	$ 77,838	$ 149,836
PS1F 2034 Limit OffSW	2,700	11,700	21,262	$ 29,616	$ 49,032	$ 79,861	$ 153,039
PS1F 2034 No Tx Tfr Rate	3,000	12,000	19,387	$ -	$ -	$ -	$ -
PS1F 2034 No Tx Tfr Limit OffSW	3,000	12,000	21,562	$ 29,616	$ 49,032	$ 79,861	$ 153,039
PS1F 2034 Revised Low Load	2,700	11,700	18,112	$ -	$ -	$ -	$ -
PS1F 2034 Limit OnSW	2,700	11,700	18,112	$ -	$ -	$ -	$ -
PS1F 2034 Accel SMR	2,700	11,700	21,262	$ 29,616	$ 49,795	$ 76,073	$ 148,133
PS1F 2034 Force 2029 DEP CC	2,700	11,700	19,162	$ -	$ -	$ -	$ -
PS1F 2034 Shared Capacity	3,000	12,000	19,087	$ 29,589	$ 51,998	$ 80,532	$ 150,501
PS1F 2034 High Gas Cost	3,000	11,850	19,012	$ -	$ -	$ -	$ -
PS1F 2034 NoEIR	2,700	11,700	17,962	$ 29,840	$ 52,327	$ 81,216	$ 151,103
PS1F 2034 EPA 40%CC Limit	2,925	12,525	23,512	$ 29,730	$ 50,448	$ 77,134	$ 149,282
PS1F 2034 Low Battery Avail	2,700	11,700	19,162	$ -	$ -	$ -	$ -
PS1F 2034 NG Cap to 4 CC	2,700	11,700	18,637	$ -	$ -	$ -	$ -
PS1F 2034 SC CC	2,700	11,700	19,312	$ 29,741	$ 49,687	$ 77,702	$ 146,556
PS1F_2034_2035OSW	2,700	11,700	21,262	$ -	$ -	$ -	$ -
PS3F_2037_Force DEP CC, 2035 OffSW, EPA 40% CF	2,700	9,225	18,787	$ 29,823	$ 49,788	$ 78,698	$ 154,343
D P2 FB 2033	3,750	12,825	20,512	$ 29,931	$ 52,085	$ 80,962	$ 154,916
D P3 FB 2035	2,700	9,000	18,037	$ 29,694	$ 51,122	$ 77,877	$ 148,966
Least Regrets	2,700	9,000	17,962	$ 28,996	$ 49,032	$ 76,073	$ 146,556
Median	2,700	11,700	19,237	$ 29,616	$ 49,737	$ 77,770	$ 149,124
Upper Bound	8,550	21,375	25,762	$ 31,954	$ 56,225	$ 92,268	$ 169,764

The least regrets evaluation identified the continued need for solar. Pre-2040, EnCompass selects the maximum – or near maximum, amount of solar allowed before exceeding the modeling interconnection limit.

The median is similar in behavior to least regrets.

The upper bound exhibits the same general behavior as the median and least regrets, continuing the buildout of solar PV up to a point, before leveling out, but with more divergence than the median, notably in the later years and when interconnection limits are relaxed.

Q. Please identify any relationships with PVRR increases or decreases across varying levels of solar PV deployment.

A. Given the MW contribution of solar in relationship to the total portfolio, solar represents a building block resource of every portfolio, with the assumptions used in the model for total costs, inclusive of transmission cost adders. Since solar is a core resource in every portfolio, portfolio PVRRs are not materially impacted by inclusion of this resource, albeit unless larger and currently unknown transmission upgrades are required.

Q. Please identify risk factors for solar PV.

A. The strategic allocation of solar resources between DEC and DEP reflects a thoughtful approach to managing the energy transition that is in line with observed trends and solicitation outcomes. While the distribution of EnCompass modeling assumptions for solar aims to balance system needs, the uncertainty of actual solar generation locations could necessitate increased energy transfers, highlighting the importance of dynamic grid management. Moreover, the physical realities of power flow directionality remain unchanged even with utility merger (DEP and DEC), underscoring the need for innovative solutions like battery storage to enhance system reliability amidst the growing integration of solar energy.

Q. Based upon your findings, does the Companies' proposed Near-Term Action Plan support your observations and modeling results?

A. Mostly yes, but partially no. The advancement of solar energy generation is crucial for sustainable development in a carbon constrained world as well as in the selection of an economic resource. The proposal for solar procurement of between 2,700 MW and 3,460 MW for 2025 and 2026 aligns with the median portfolio range, suggesting a balanced approach. However, considering the load growth projections and the need to meet interim compliance targets, I believe it is prudent to target the upper end of the range at this time. Additionally, if the Commission's order on the CPIRP calls for more solar interconnections, procurement targets must be adjusted accordingly, keeping in mind reliability concerns. As demand grows, the procurement of solar energy may also need to scale up in proportion to the incremental load of each balancing authority.

I support Public Staff witness Thomas in his recommendations on additionality or incremental ways to achieve even more annual solar interconnections in a year by targeting areas that would not require scheduled transmission outages.

Q. Are there any additional items regarding solar PV that you would like to bring to the Commission's attention?

A. Yes. The integration of solar resources into the existing energy system necessitates a strategic approach to manage curtailments and optimize storage solutions. As solar deployment expands, the potential for energy curtailment increases, highlighting the need for more robust battery storage capabilities. In scenarios where SPS is insufficient, the Companies may need to invest in additional stand-alone storage infrastructure of their own.

If the Companies do not develop and deploy energy storage at a commensurate pace of solar interconnections, negative impacts are likely to occur at the Companies nuclear generation fleet, absent substantial solar curtailments. The existing nuclear fleet, with its substantial nameplate capacity, represents a critical asset that can be leveraged to ensure a reliable and economic energy supply. The future energy system design should consider the valuable contributions of nuclear power, maintaining its role where viable and economical, promoting nuclear safety, while also integrating new renewable resources. The interplay with solar and nuclear generation is discussed in more detail in the Reliability section of my testimony.

Q. Do any of the Public Staff's portfolios or sensitivities cause you concern?

A. Yes. My testimony has attempted to highlight the intricate balance between advancing renewable energy targets, carbon reductions, and maintaining grid reliability. While I am not an attorney, my reading of the plain language of S.L. 2021-165 (HB 951) Part I, Section 1 (3), "Ensure any generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid," underscores the Commission's legislative mandate to ensure any changes in generation resources do not compromise the grid's reliability. The Public Staff's Portfolio PS1F 2030 No CC High Grid Edge serves as a case study for attempting to achieve HB 951compliance by 2030. This portfolio calls for approximately 20 GW of solar energy by 2030, 30 GW of solar energy by 2033, 36 GW of solar energy by 2038, compared to the presently online solar energy amount of 4.5GW (2023) in DEC's and DEP's service areas. The concerns about the potential impact of aggressive solar procurement on grid reliability reflect the complexities of integrating a significant amount of solar capacity, especially considering the current constraints and limitations on annual solar interconnections and the necessity to manage transmission outage windows. Setting overly ambitious, and likely unrealistic, solar procurement targets without comprehensive transmission and system-level planning is imprudent, given the risk of compromising grid reliability.

Battery Storage

Q. Please discuss the results of your analysis of battery storage impacts across multiple portfolios.

A. Battery storage is comprised of two buckets: storage co-located with solar PV (or "solar plus storage," earlier abbreviated as SPS) and standalone storage. Given the amount of solar generation being added, in addition to other carbon free resources, it is reasonable to store energy during lower load periods or due to economic price arbitrage and later discharge the energy based upon system need or cost. Increases in renewable generation have a direct correlation to increases in battery storage deployment.

Figure 5 below lists the SPS as selected across multiple portfolios, as also shown in Exhibit 2.

Figure 5: Battery paired with Solar Capacity (SPS)

Duke Energy Carolinas and Duke Energy Progress System Capacity							
	Battery paired with Solar			PVRR			
Portfolio	2029	2033	2038	2029	2033	2038	2050
PS1F 2030 No CC High Grid Edge	5,560	9,680	9,680	$ 31,954	$ 55,236	$ 84,623	$ 155,973
PS1F 2032	1,880	7,460	7,460	$ 28,996	$ 56,225	$ 92,268	$ 169,764
PS1F 2034	1,040	3,260	4,300	$ 29,616	$ 52,090	$ 80,857	$ 150,785
PS1F 2035	1,040	2,660	5,700	$ 29,677	$ 49,876	$ 77,838	$ 149,836
PS1F 2034 Limit OffSW	1,040	6,040	7,960	$ 29,616	$ 49,032	$ 79,861	$ 153,039
PS1F 2034 No Tx Tfr Rate	1,200	4,220	5,660	$ -	$ -	$ -	$ -
PS1F 2034 No Tx Tfr Limit OffSW	1,200	5,160	6,640	$ 29,616	$ 49,032	$ 79,861	$ 153,039
PS1F 2034 Revised Low Load	1,040	4,120	5,160	$ -	$ -	$ -	$ -
PS1F 2034 Limit OnSW	1,040	4,580	5,620	$ -	$ -	$ -	$ -
PS1F 2034 Accel SMR	1,040	3,960	8,960	$ 29,616	$ 49,795	$ 76,073	$ 148,133
PS1F 2034 Force 2029 DEP CC	1,040	3,940	4,980	$ -	$ -	$ -	$ -
PS1F 2034 Shared Capacity	1,200	4,580	5,820	$ 29,589	$ 51,998	$ 80,532	$ 150,501
PS1F 2034 High Gas Cost	1,040	3,880	4,920	$ -	$ -	$ -	$ -
PS1F 2034 NoEIR	1,040	4,040	5,080	$ 29,840	$ 52,327	$ 81,216	$ 151,103
PS1F 2034 EPA 40%CC Limit	1,040	3,440	8,060	$ 29,730	$ 50,448	$ 77,134	$ 149,282
PS1F 2034 Low Battery Avail	1,040	3,880	5,340	$ -	$ -	$ -	$ -
PS1F 2034 NG Cap to 4 CC	1,040	4,520	5,560	$ -	$ -	$ -	$ -
PS1F 2034 SC CC	1,040	4,200	5,660	$ 29,741	$ 49,687	$ 77,702	$ 146,556
PS1F_2034_2035OSW	1,040	5,560	8,120	$ -	$ -	$ -	$ -
PS3F_2037_Force DEP CC, 2035 OffSW, EPA 40% CF	1,040	4,540	8,380	$ 29,823	$ 49,788	$ 78,698	$ 154,343
D P2 FB 2033	1,120	3,740	5,600	$ 29,931	$ 52,085	$ 80,962	$ 154,916
D P3 FB 2035	1,040	1,780	4,520	$ 29,694	$ 51,122	$ 77,877	$ 148,966
Least Regrets	1,040	1,780	4,300	$ 28,996	$ 49,032	$ 76,073	$ 146,556
Median	1,040	4,160	5,660	$ 29,616	$ 49,737	$ 77,770	$ 149,124
Upper Bound	5,560	9,680	9,680	$ 31,954	$ 56,225	$ 92,268	$ 169,764

Absent the first two portfolios in the table (which correspond to 2030 and 2032 compliance, respectively), the overall amounts of battery storage selected across the other portfolios compared to the least regrets evaluation is relatively the same magnitude for 2033, before a larger divergence begins after 2033 and continues into 2038. For portfolios without accelerated SMR deployment, battery storage begins to level off from 2033 to 2038, and as listed in Figure 6 below, standalone storage becomes more prevalent as a selected resource later in the planning horizon.

The median for 2033 is the same as the least regrets evaluation and exhibits similar trends as least regrets.

The upper bound is skewed by a single plan in 2029 (2030 compliance with no CC and high grid edge) and 2033, but other plans trend to a higher level in 2038 as well.

Figure 6 below lists the results of standalone battery resources across multiple portfolios, as also shown in Exhibit 2.

Figure 6: Battery Standalone Capacity

Duke Energy Carolinas and Duke Energy Progress System Capacity							
	Battery Standalone			PVRR			
Portfolio	2029	2033	2038	2029	2033	2038	2050
PS1F 2030 No CC High Grid Edge	3,100	6,100	6,100	$ 31,954	$ 55,236	$ 84,623	$ 155,973
PS1F 2032	1,700	5,100	5,100	$ 28,996	$ 56,225	$ 92,268	$ 169,764
PS1F 2034	200	400	1,400	$ 29,616	$ 52,090	$ 80,857	$ 150,785
PS1F 2035	200	200	2,000	$ 29,677	$ 49,876	$ 77,838	$ 149,836
PS1F 2034 Limit OffSW	200	3,100	4,100	$ 29,616	$ 49,032	$ 79,861	$ 153,039
PS1F 2034 No Tx Tfr Rate	300	300	1,500	$ -	$ -	$ -	$ -
PS1F 2034 No Tx Tfr Limit OffSW	300	2,600	3,600	$ 29,616	$ 49,032	$ 79,861	$ 153,039
PS1F 2034 Revised Low Load	300	300	1,300	$ -	$ -	$ -	$ -
PS1F 2034 Limit OnSW	200	300	1,300	$ -	$ -	$ -	$ -
PS1F 2034 Accel SMR	200	200	2,000	$ 29,616	$ 49,795	$ 76,073	$ 148,133
PS1F 2034 Force 2029 DEP CC	200	500	1,600	$ -	$ -	$ -	$ -
PS1F 2034 Shared Capacity	300	400	1,400	$ 29,589	$ 51,998	$ 80,532	$ 150,501
PS1F 2034 High Gas Cost	-	100	1,600	$ -	$ -	$ -	$ -
PS1F 2034 NoEIR	100	100	1,100	$ 29,840	$ 52,327	$ 81,216	$ 151,103
PS1F 2034 EPA 40%CC Limit	100	1,400	2,300	$ 29,730	$ 50,448	$ 77,134	$ 149,282
PS1F 2034 Low Battery Avail	100	300	1,300	$ -	$ -	$ -	$ -
PS1F 2034 NG Cap to 4 CC	200	600	1,600	$ -	$ -	$ -	$ -
PS1F 2034 SC CC	100	600	1,600	$ 29,741	$ 49,687	$ 77,702	$ 146,556
PS1F_2034_2035OSW	200	3,600	5,600	$ -	$ -	$ -	$ -
PS3F_2037_Force DEP CC, 2035 OffSW, EPA 40% CF	-	1,000	2,700	$ 29,823	$ 49,788	$ 78,698	$ 154,343
D P2 FB 2033	400	2,300	2,800	$ 29,931	$ 52,085	$ 80,962	$ 154,916
D P3 FB 2035	800	800	1,800	$ 29,694	$ 51,122	$ 77,877	$ 148,966
Least Regrets	-	100	1,100	$ 28,996	$ 49,032	$ 76,073	$ 146,556
Median	200	550	1,700	$ 29,616	$ 49,737	$ 77,770	$ 149,124
Upper Bound	3,100	6,100	6,100	$ 31,954	$ 56,225	$ 92,268	$ 169,764

The least regrets evaluation amount varies across the portfolios. Limiting offshore wind and an earlier interim compliance date tend to favor more standalone battery storage, likely requiring carbon-free energy to be sourced, stored, and reused in order to meet carbon compliance.

The median is similar to the least regrets trend but highlights further divergence in certain portfolios.

The upper bound is similar to the SPS upper bound. When battery storage is deployed in larger numbers by 2033, a leveling off begins in some instances such that no new battery storage is added from 2033 to 2038. This reality likely suggests standalone battery storage is being selected after SPS to meet carbon compliance targets and modeling constraints.

Q. Please identify any relationships with PVRR increases or decreases across varying levels of battery storage deployment.

A. Higher battery deployments often occur in earlier interim compliance portfolios and boundary cases,[30] which test the feasibility and reasonableness of potential outcomes. Thus, it is reasonable that portfolios with higher battery storage deployment will have higher PVRRs, but multiple factors contribute to that outcome.

[30] A boundary case in this example refers to a portfolio or modeling sensitivity which stresses a potential outcome even though it may not be technically or practically feasible to implement. For example, I would classify PS 1F 2030 No CC High Grid Edge results as a boundary case as it is not practical to implement in its entirety.

Q. Please identify risk factors for battery storage.

A. The integration of battery storage into energy portfolios is a complex yet critical aspect of modern energy systems. It offers the flexibility to adjust energy supply in response to fluctuating demand and generation, particularly with the increasing integration of intermittent renewable energy sources. The economic value of battery storage is multifaceted, encompassing capacity deferral, provision of operating reserves, and energy time-shifting. As the share of renewable energy grows, the role of battery storage becomes more significant, necessitating careful consideration of its deployment to optimize system reliability and economic efficiency.

Q. Based upon your findings, does the Companies' proposed Near-Term Action Plan support your observations and modeling results?

A. Generally, yes. As stated above, the integration of battery storage is becoming a cornerstone of modern utility systems, particularly with the shift towards intermittent renewable energy sources. The expansion of SPS procurement targets can strategically bolster energy reliability as SPS "firms" the otherwise intermittent nature of standalone solar PV and can respond rapidly to other grid events. Furthermore, reevaluating the duration of storage is essential to maximizing the benefits of energy storage, ensuring that it aligns with the fluctuating nature of energy demand and generation. As utility models evolve, the trend towards longer duration storage seems to be gaining traction, offering a more resilient and adaptable energy infrastructure.

Q. Are there any additional items regarding battery storage that you would like to bring to the Commission's attention?

A. Yes. The evolution of battery storage technology has been marked by incremental improvements until a saturation point is reached, after which a significant technological leap is often observed. This pattern reflects the ongoing advancements in energy storage, in which longer-duration batteries or larger battery-to-solar ratios are developed over time. As these technologies mature and plateau, the industry shifts focus to the next tier of innovation, ensuring a continuous progression in energy storage solutions. This cycle of growth and transition is vital for enhancing the efficiency and reliability of renewable energy systems.

Onshore Wind

Q. Please discuss the results of your analysis of onshore wind impacts across multiple portfolios.

A. Onshore wind was selected in every portfolio modeled with very minor deviations. Public Staff witness Lawrence discusses his concerns with onshore wind, including the assumptions made by the Companies, and sponsors a limited onshore wind sensitivity (PS1F 2034 Limit OnSW) that was modeled in EnCompass.

Figure 7 below lists the results of onshore wind selection across multiple portfolios, as shown in Exhibit 2.

Figure 7: Onshore Wind Capacity

Duke Energy Carolinas and Duke Energy Progress System Capacity							
	Onshore Wind			PVRR			
Portfolio	2029	2033	2038	2029	2033	2038	2050
PS1F 2030 No CC High Grid Edge	-	2,100	2,100	$ 31,954	$ 55,236	$ 84,623	$ 155,973
PS1F 2032	-	2,100	2,100	$ 28,996	$ 56,225	$ 92,268	$ 169,764
PS1F 2034	-	1,800	2,250	$ 29,616	$ 52,090	$ 80,857	$ 150,785
PS1F 2035	-	1,350	2,250	$ 29,677	$ 49,876	$ 77,838	$ 149,836
PS1F 2034 Limit OffSW	-	1,800	2,250	$ 29,616	$ 49,032	$ 79,861	$ 153,039
PS1F 2034 No Tx Tfr Rate	-	1,800	2,250	$ -	$ -	$ -	$ -
PS1F 2034 No Tx Tfr Limit OffSW	-	1,800	2,250	$ 29,616	$ 49,032	$ 79,861	$ 153,039
PS1F 2034 Revised Low Load	-	1,800	2,250	$ -	$ -	$ -	$ -
PS1F 2034 Limit OnSW	-	1,800	2,250	$ -	$ -	$ -	$ -
PS1F 2034 Accel SMR	-	1,800	2,250	$ 29,616	$ 49,795	$ 76,073	$ 148,133
PS1F 2034 Force 2029 DEP CC	-	1,800	2,250	$ -	$ -	$ -	$ -
PS1F 2034 Shared Capacity	-	1,800	2,250	$ 29,589	$ 51,998	$ 80,532	$ 150,501
PS1F 2034 High Gas Cost	-	1,800	2,250	$ -	$ -	$ -	$ -
PS1F 2034 NoEIR	-	1,800	2,250	$ 29,840	$ 52,327	$ 81,216	$ 151,103
PS1F 2034 EPA 40%CC Limit	-	2,100	2,250	$ 29,730	$ 50,448	$ 77,134	$ 149,282
PS1F 2034 Low Battery Avail	-	1,800	2,250	$ -	$ -	$ -	$ -
PS1F 2034 NG Cap to 4 CC	-	1,800	2,250	$ -	$ -	$ -	$ -
PS1F 2034 SC CC	-	1,800	2,250	$ 29,741	$ 49,687	$ 77,702	$ 146,556
PS1F_2034_2035OSW	-	1,950	2,250	$ -	$ -	$ -	$ -
PS3F_2037_Force DEP CC, 2035 OffSW, EPA 40% CF	-	1,200	2,250	$ 29,823	$ 49,788	$ 78,698	$ 154,343
D P2 FB 2033	-	2,100	2,250	$ 29,931	$ 52,085	$ 80,962	$ 154,916
D P3 FB 2035	-	1,200	2,250	$ 29,694	$ 51,122	$ 77,877	$ 148,966
Least Regrets	-	1,200	2,100	$ 28,996	$ 49,032	$ 76,073	$ 146,556
Median	-	1,800	2,250	$ 29,616	$ 49,737	$ 77,770	$ 149,124
Upper Bound	-	2,100	2,250	$ 31,954	$ 56,225	$ 92,268	$ 169,764

The least regrets evaluation appears to be impacted by the interim compliance year. The median and upper bound are generally the same across all portfolios, noting that the earlier the compliance date, the larger the procurement in 2033. If the Commission selects a later interim compliance date, the amount of onshore wind procurement in the Public Staff's NTAP could and should be reduced accordingly.

Q. Please identify any relationships with PVRR increases or decreases across varying levels of onshore wind deployment.

A. No relationship can be identified at this time. Onshore wind deployment is generally the same across all portfolios with minor deviations in all but two model runs (i.e., model runs with later interim compliance). Thus, while onshore wind has relatively high CapEx costs compared to other technologies, onshore wind does not cause significant PVRR variability among the modeled portfolios since it is selected in all portfolios and the variance of total capacity selected across all portfolios is relatively minor.

Q. Please identify risk factors for onshore wind.

A. Witness Lawrence testifies to his concerns about the uncertain deployment of wind resources, and I support his observations. I consider the ability to site onshore wind facilities across North Carolina and South Carolina as the greatest hurdle to ensure commercial operation by the Companies' proposed dates. North Carolina has numerous military bases that limit the deployment of future wind resources, particularly in the eastern part of the state where wind potential is likely highest. In addition, the overall onshore wind potential is not as strong as in the Midwest states.

Q. Based upon your findings, does the Companies' proposed Near-Term Action Plan for onshore wind support your observations and modeling results?

A. The Companies' NTAP for onshore wind is too vague and should not be approved as requested. The Companies' description of onshore wind development provides no insight as to the electric utility service area in which they plan to develop onshore wind. In addition, multiple Public Staff model runs suggest that an even greater volume of onshore wind should be developed by 2033 if the Commission chooses an earlier interim compliance year target.

Q. Are there any additional items regarding onshore wind that you would like to bring to the Commission's attention?

A. Yes. Developing a comprehensive plan for and backup plan to onshore wind deployment should be crucial for the Companies, especially considering the complexities of onshore wind resource development in the Carolinas. The timeline for establishing onshore wind resources could span approximately six years, subject to factors such as site selection, environmental assessments, military interactions, and community engagement. Due to the high potential for delays, it is prudent to explore a diverse mix of alternative generation resources. Strategic planning and investment in a broad portfolio of generation resources can mitigate risks associated with project timelines for onshore wind.

Offshore Wind

Q. Please discuss the results of your analysis of offshore wind impacts across multiple portfolios.

A. The economic viability of offshore wind as an energy resource is closely tied to carbon policy, indicating that its selection is often contingent on meeting carbon emission targets. The modeling sensitivities suggest that current economic and regulatory uncertainties, particularly the CAA Rule and its impact on natural gas generation, play a significant role in the decision-making process for offshore wind development. The testimony of Public Staff witness Williamson highlights the financial implications of offshore wind, noting an initial increase in short-term rates but projecting an overall decrease by the late 2030s due to the advantages of a resource with no fuel costs and a substantial capacity factor. Furthermore, the interplay between SMR deployment and offshore wind development suggests a competitive dynamic in which accelerated nuclear options may inhibit the growth of offshore wind, and which is compounded by the regulatory environment in South Carolina, where natural gas generation does not contribute to HB 951 compliance in North Carolina. In addition, delays in HB 951 compliance timelines further impact offshore wind deployment. Collectively, these factors underscore the complexity of integrating offshore wind into the energy mix, where carbon compliance and firm energy demand are pivotal drivers.

Figure 8 below lists the results of the offshore wind selection across multiple portfolios, as also shown in Exhibit 2. For context, the Companies modeled 800 MW blocks of offshore wind and (as discussed by Public Staff witness Lawrence) the Public Staff used 1,100 MW blocks for its modeling. Each block, regardless of size modeled, is intended to show the potential electrical energy that can be generated offshore and brought onshore from each general lease area. Each offshore block could consist of 50-70 individual 15 MW turbines.[31]

Figure 8: Offshore Wind Capacity

Duke Energy Carolinas and Duke Energy Progress System Capacity							
	Offshore Wind			PVRR			
Portfolio	2029	2033	2038	$ 2,029	$ 2,033	$ 2,038	$ 2,050
PS1F 2030 No CC High Grid Edge	-	1,100	1,100	$ 31,954	$ 55,236	$ 84,623	$ 155,973
PS1F 2032	-	3,300	4,400	$ 28,996	$ 56,225	$ 92,268	$ 169,764
PS1F 2034	-	3,300	4,400	$ 29,616	$ 52,090	$ 80,857	$ 150,785
PS1F 2035	-	-	2,200	$ 29,677	$ 49,876	$ 77,838	$ 149,836
PS1F 2034 Limit OffSW	-	1,100	2,200	$ 29,616	$ 49,032	$ 79,861	$ 153,039
PS1F 2034 No Tx Tfr Rate	-	3,300	4,400	$ -	$ -	$ -	$ -
PS1F 2034 No Tx Tfr Limit OffSW	-	1,100	2,200	$ 29,616	$ 49,032	$ 79,861	$ 153,039
PS1F 2034 Revised Low Load	-	-	1,100	$ -	$ -	$ -	$ -
PS1F 2034 Limit OnSW	-	3,300	4,400	$ -	$ -	$ -	$ -
PS1F 2034 Accel SMR	-	-	-	$ 29,616	$ 49,795	$ 76,073	$ 148,133
PS1F 2034 Force 2029 DEP CC	-	3,300	4,400	$ -	$ -	$ -	$ -
PS1F 2034 Shared Capacity	-	3,300	4,400	$ 29,589	$ 51,998	$ 80,532	$ 150,501
PS1F 2034 High Gas Cost	-	3,300	4,400	$ -	$ -	$ -	$ -
PS1F 2034 NoEIR	-	3,300	4,400	$ 29,840	$ 52,327	$ 81,216	$ 151,103
PS1F 2034 EPA 40%CC Limit	-	-	-	$ 29,730	$ 50,448	$ 77,134	$ 149,282
PS1F 2034 Low Battery Avail	-	4,400	4,400	$ -	$ -	$ -	$ -
PS1F 2034 NG Cap to 4 CC	-	4,400	4,400	$ -	$ -	$ -	$ -
PS1F 2034 SC CC	-	-	1,100	$ 29,741	$ 49,687	$ 77,702	$ 146,556
PS1F_2034_2035OSW	-	-	2,200	$ -	$ -	$ -	$ -
PS3F_2037_Force DEP CC, 2035 OffSW, EPA 40% CF	-	-	1,100	$ 29,823	$ 49,788	$ 78,698	$ 154,343
D P2 FB 2033	-	2,400	2,400	$ 29,931	$ 52,085	$ 80,962	$ 154,916
D P3 FB 2035	-	800	2,400	$ 29,694	$ 51,122	$ 77,877	$ 148,966
Least Regrets	-	-	-	$ 28,996	$ 49,032	$ 76,073	$ 146,556
Median	-	1,750	2,400	$ 29,616	$ 49,737	$ 77,770	$ 149,124
Upper Bound	-	4,400	4,400	$ 31,954	$ 56,225	$ 92,268	$ 169,764

[31] 15 MW is illustrative.

Given the impacts of the multiple portfolios that did not select or delayed selection of offshore wind, the least regrets amount is skewed. Removal of the four portfolios that did not select wind in 2033 results in a least regret amount of approximately 1,100 MW, or 800 MW using the Companies' modeling assumption. The least regrets evaluation for 2038, with the removal of the four previously discussed model sensitivities, results in approximately 2,200 MW of offshore wind.

Most portfolios selected offshore wind with some selecting even larger quantities in 2033. The median in 2033 would be 2,200 MW to 3,300 MW, or 1,600 MW to 2,400 MW using 800 MW blocks from the Companies' modeling assumption. The models point to a 2038 target amount of 3,200 MW to 3,300 MW, again depending upon which size assumption is used for the block size.

None of the modeling results selected all five wind blocks the Public Staff included as selectable resources. The two sensitivities that limited natural gas to a maximum of four CCs and the low battery storage sensitivity limit selected 4,400 MW of offshore wind by 2033. Battery storage was discussed earlier in my testimony, but it is worth noting that there is a relationship between the selection of offshore wind and the interim compliance date and/or a large energy need.

Q. Please identify any relationships with PVRR increases or decreases across varying levels of offshore wind deployment.

A. Based upon the Public Staff's model runs, which included production costs, model runs with increased offshore wind result in generally higher PVRR impacts in 2033 and 2038 as compared to model sensitivities that did not select or selected less offshore wind.

Q. Please identify risk factors for offshore wind.

A. The development of offshore wind facilities presents a multifaceted challenge, encompassing not only the financial investment but also the logistics of onshore integration. The process of constructing and bringing undersea cables onto land, particularly in areas with existing energy infrastructure, such as the Brunswick Nuclear Station and Sutton CC Plant, will require careful planning to avoid overloading the existing transmission system. The presence of significant solar generation west of both Brunswick and Sutton further complicates the potential for grid impacts, necessitating strategic placement of interconnection points to balance incremental generation and load. Moreover, the potential for regulatory changes, such as those related to the CAA Rule, adds another layer of complexity to project planning. It is crucial to consider the cumulative impact of offshore wind procurement and to establish clear guidelines for interconnection locations to validate the economics of these projects.

The integration of offshore wind into the energy mix presents an opportunity to enhance fuel diversity. Fuel diversity allows for a more stable and reliable energy grid, especially during times when other renewable sources like solar may be less reliable due to weather conditions. Fuel diversity also helps dampen impacts of rapid changes in fuel forecasts from both a supply and monetary amount. Moreover, geographic diversification of energy resources brings balance and security across different areas of the grid, mitigating risks associated with localized energy production shortfalls. While production cost modeling provides valuable insights, it may not fully capture the broader economic and reliability benefits of such diversification. The approach reflected in model sensitivities that reduce or delay offshore wind deployment are attributable to the complex interplay of technological, environmental, military, and economic factors that must be considered in long-term energy planning. Nevertheless, the intrinsic value of resource and location diversity in enhancing grid stability and reducing dependency on single energy sources remains a compelling argument for further evaluation of offshore wind in the energy portfolio.

Q. Based upon your findings, does the Companies' proposed Near-Term Action Plan support your observations and modeling results?

A. Yes and no. Resource planning is a multifaceted endeavor, especially when integrating technologies that are new to the existing grid. Duke Energy Corporation's Executive Vice President Brian Savoy recently emphasized the need for a diverse mix of resources to meet future energy demands.[32] The Companies' cautious approach towards offshore wind in this CPIRP, contrasted with their more vigorous pursuit of natural gas, reflects the complexities of balancing renewable resources with those resources with which the Companies have operational experience and upon which the Companies have traditionally relied.

However, the ambiguity of the Companies' ARFI approach and its impact on the Carbon Plan highlights the necessity for transparent and efficient cost models and contract execution. The juxtaposition of the insistence of Commission preapproval for an offshore wind ARFI against the swift movement toward more natural gas projects illustrates the broader industry tension: the need for rapid development of traditional infrastructure versus the prioritization of other resources like offshore wind, as well as other generation resources. Nevertheless, with the potential rise in costs for offshore wind projects, economic viability remains a critical concern. It is indeed reasonable for the Companies to collaborate with developers to effectively structure contract negotiations. Such collaborations can provide valuable insights without necessitating Commission approval, aligning with good utility practice and standard business operations. Adoption of the Public Staff's NTAP for offshore wind approach not only fosters innovation

[32] S&P Global Commodity Insights, "Duke increases load growth forecasts again, citing economic development boom," May 7, 2024.

but also ensures that the energy sector can adapt to evolving market conditions and regulatory landscapes.

Q. Are there any additional items regarding offshore wind that you would like to bring to the Commission's attention?

A. Yes. The transition to incorporation of offshore wind energy resources in the Carolinas represents potential risks given current trends and uncertainty. The concerns raised previously about the need for robust price bidding contract structures and index-priced contracts to mitigate inflation and unforeseen circumstances are valid, considering the volatility of the energy market. It is crucial for the Commission to conduct a thorough analysis to determine the optimal volume of offshore wind that aligns with the CPIRP's objectives. The timing of the ARFI and subsequent CPIRP filings is critical as noted in the Public Staff motion filed April 17, 2024, because outdated cost information can lead to a cyclical loop of revisions and delays.

Duke's proposed ARFI presents a challenge to securing developer commitments due to the inherent uncertainties in project execution and the lack of a clear solicitation process. A structured approach, with well-defined steps and timelines, is essential to ensure that offshore wind development proceeds in an orderly and economically viable manner, including additional actions beyond those listed in the Companies' NTAP, and guided by accurate load forecasting and modeling results, to effectively integrate offshore wind into the region's energy portfolio. I propose a scalable offshore wind procurement target and concepts for consideration for inclusion in the Public Staff NTAP. However, given the magnitude of offshore wind costs, timing uncertainty, and current cost information, more discrete and actionable items should be prescribed while balancing ratepayer protections. Hiring a facilitator or independent entity (IE), or equivalent, is a reasonable step given the complexity of such a large technology addition. Defining the scope of such a facilitator or IE was beyond the scope of my investigation and would require extensive work to properly define.

IX. RELIABILITY

Q. Please describe the intent of this section of your testimony.

A. It is crucial to recognize the importance of aligning reliability metrics with real-world operating conditions. Production cost models such as EnCompass are valuable tools for forecasting and planning, but they must be scrutinized against actual performance data to ensure the results they produce result in a reliable grid under a range of uncertainties and grid conditions. By analyzing historical trends and integrating with current observations, the system planner(s) can identify discrepancies and risks between projected and actual outcomes. This process not only enhances the robustness of reliability metrics but also informs future improvements in system planning, design, and operation. It is through this meticulous approach that risks can be both anticipated and mitigated, ensuring a resilient and dependable energy grid for the future.

Q. Provide a summary of your reliability section of your testimony.

A. The evolving landscape of the energy sector, with its increasing reliance on renewable sources, presents challenges for grid management. The reserve margin, a critical indicator of the grid's ability to meet peak demand, has been a focal point of recent analyses. The Companies have made investments in their existing generation fleet to address reliability trends, such as the need for cold weather hardening projects as part of their respective multiyear rate plans. Furthermore, system operators require advanced tools and technologies to manage periods of peak demand as well as lower load periods, while also ensuring reliability throughout the year.

As I've stated before, the integration of solar energy into the grid introduces additional, unique complexities. Continuing the current path will likely result in an increase in solar curtailment or the need to cycle nuclear plants more frequently to accommodate the variability of solar power. This reality highlights the necessity for the Commission to consider the implications of solar ramping, where the rapid increase or decrease of this variable resource poses operational issues or constraints on the grid's ability to quickly respond to changes in demand. An adequate plan to address these challenges is crucial for maintaining grid reliability and optimizing the mix of generation resources to support a sustainable, resilient, and least-cost energy future.

Q. Have you provided previous testimony on the Companies natural gas and coal generation fleets?

A. Yes. I filed testimony in Dockets Nos. E-2, Sub 1300 and E-7, Sub 1276, providing a comprehensive analysis of the operational trends and financial decisions impacting the fossil fleets of the Companies. My detailed examination during these dockets revealed negative performance trends within the fossil fleets, underscoring the complexity and futility of evaluating system performance through a single metric. The reduction in workforce at specific generation stations, coupled with a decrease in operations and maintenance (O&M) budgets post-past rate cases, indicates a deviation from the level of expenditures the Public Staff, and presumably the Commission, expected. Furthermore, my testimony in those dockets addresses the Companies' proposed proforma adjustments to the test year expenses, which at the time had a goal of enhancing the reliability of the coal generation assets. These adjustments included expenditures for reliability threat analysis, winterization, reliability improvements, staffing, and spare parts, among others. The Commission's approval of the reliability assurance proformas signified its recognition of the necessity for these expenditures to maintain and improve the reliability of the coal generation assets.

Q. Are the Companies' proposed reserve margin increases in this CPIRP impacted by the increase in outages detailed in your rate case testimonies?

A. Yes. Public Staff witness Thomas discusses the reserve margin impacts in more detail in his testimony. Mr. Thomas also shows the ratio of each type of plant that impacts the overall equivalent forced outage rate on a system weighted average basis.

Q. Do you have concerns or observations about the declining reliability of resources during extreme winter weather?

A. Yes. It is important to note that certain generation plants have been in service for decades and are reaching the end of their useful life; therefore, it is reasonable to expect a decline in operating performance. However, as I testified in the DEC and DEP rate case dockets listed above, I have observed trends of (1) the Companies' decreasing O&M spending in certain business groups of their generation fleets, and (2) the Companies' proposed reserve margin increase in this proceeding is not reflective of the additional projects and increased spending they used to justify base rate increases in the MYRP proceedings. The decrease in maintenance spending, including a reduction in craft employees, has likely contributed to the increase in outage rates and impacted the time it takes to make repairs as needed for the restoration of, and/or improvement to, system reliability, as also noted in Public Staff witness Thomas' testimony. The Companies' actions to reduce O&M costs and reduce employee head count may have inadvertently contributed to the need to increase the overall reserve margin. To quote an old adage, in some instances they may have been penny wise, but pound foolish.

Q. Please provide a summary of why you believe the Commission should be concerned about low load days and how they can lead to system reliability issues.

A. The Commission has likely heard about the "Duck Curve." "The duck curve—named after its resemblance to a duck—shows the difference in electricity demand and the amount of available solar energy throughout the day. When the sun is shining, solar floods the market and then drops off as electricity demand peaks in the evening."[33] "High solar adoption creates a challenge for utilities to balance supply and demand on the grid. This is due to the increased need for electricity generators to quickly ramp up energy production when the sun sets and the contribution from PV falls. Another challenge with high solar adoption is the potential for PV to produce more energy than can be used at one time, called overgeneration. This leads system operators to curtail PV generation, reducing its economic and environmental benefits. While curtailment does not have a major impact on

33 https://www.energy.gov/eere/articles/confronting-duck-curve-how-address-over-generation-solar-energy

the benefits of PV when it occurs occasionally throughout the year, it could have a potentially significant impact at greater PV penetration levels." [34]

In other words, the lower the system load is in relationship to the total amount of solar connected to the system, the greater the likelihood system operators will need to call for solar curtailment and to deal with ramping challenges of other system resources. The more solar curtailment that occurs, given its lack of fuel costs, the more negatively the impact to the economics of the project due to less generation (MWh) over which to spread the total fixed costs. A weakness of the EnCompass model is that it does not structure future solar additions as power purchase agreements, but treats them as 100% owned by the utility.

Q. Have you prepared graphs that illustrate the "Duck Curve" and the overall impacts to DEC and DEP system reliability?

A. Yes, but first I would like to address a couple of discrete topics. The graphs (further below) show an acronym LROL, which stands for Lowest Reliability Operating Limit. LROL is meant to provide system operators with a metric to ensure adequate system reserves in the event of the loss of a unit, often referred to as N-1 planning (contingency planning).

Earlier in my testimony I discussed the amount of pre-existing nuclear generation located in the DEC and DEP fleets. While nuclear power plants

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[34] Id.

can be cycled, some faster than others, it is not a preferred practice as cycling nuclear power plants reduces their efficiency, as they typically have the lowest fuel costs but highest CapEx costs on the Companies' systems. As a result, reduced nuclear energy output increases costs to all ratepayers and joint owners in certain cases.

The LROL limit assumes that the Companies will have a backup generation plant able to respond in the event a nuclear power plant trips offline, as happens from time to time because they are large, complex machines with many systems and moving parts. My analysis focused on shoulder seasons when system loads are low, and when nuclear power plants take refueling outages. A nuclear refueling outage lowers the LROL requirement in terms of MW and creates more head room for a larger solar penetration amount.

As part of my analysis, I made simplifying assumptions with regard to how battery storage would be used during these low load periods. Overall, my analysis does not determine an absolute or expected number or total MWs of curtailments, but rather shows the trend and overall magnitude of the impacts on each utility in isolation, as well as the two systems as they operate and share energy today.

First, I selected a representative year and isolated the top 10 lowest total aggregated load days as well as the 10 lowest absolute load hours in each year. For purposes of my initial analysis, I selected 2035 as the analysis year.

Tables 2 and 3 below are ranked from "1" being the lowest load day to "10" being the 10th lowest load day. I highlighted similar dates in both metrics, showing that there is a relationship between the absolute lowest hourly load for a day and the total aggregate load for a day. The analysis concludes that the shoulder seasons of April and May, as well as October, are generally the months in which "low load" occurs, with some occasional spillover to adjacent months. There would likely be more spillovers if the results were expanded to 25 or even 50 low load periods.

Listed below are the results of my DEC analysis for the 10 lowest load periods and the dates on which they occurred.

Table 2: DEC Lowest Load

Duke Energy Carolinas					
Year					
2035	Top 10 Minimum 24 Hour Total Load	Date		Top 10 Minimum Hourly Load	Date
1	239,579	5/6/2035		7,350	10/14/2035
2	240,978	10/21/2035		7,492	10/21/2035
3	241,383	9/30/2035		7,509	3/25/2035
4	242,133	10/14/2035		7,526	5/27/2035
5	244,363	3/25/2035		7,534	4/15/2035
6	248,738	4/15/2035		7,544	4/22/2035
7	249,585	4/22/2035		7,656	4/29/2035
8	250,376	5/13/2035		7,707	5/6/2035
9	250,549	5/5/2035		7,734	10/7/2035
10	252,969	10/28/2035		7,760	5/13/2035

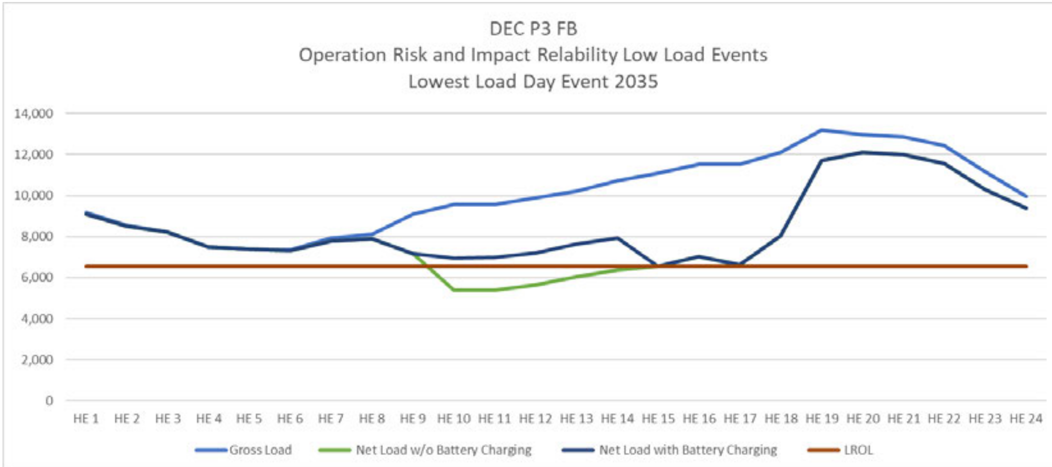
Listed below are the DEP results:

Table 3: DEP Lowest Load

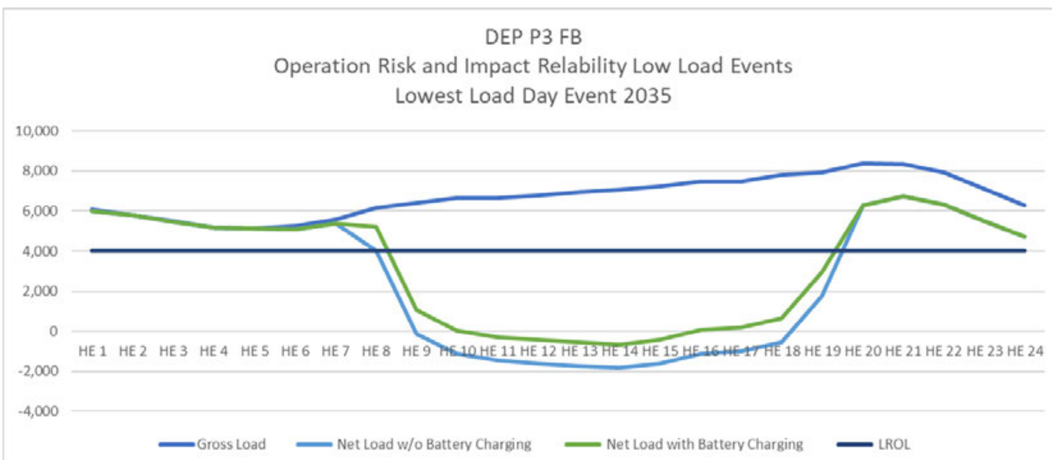
Duke Energy Progress					
2035	Top 10 Minimum Loads 24 Hour Load	Date		Top 10 Minimum Hourly Load	
1	161060	4/15/2035		5127.47	4/15/2035
2	161539	5/6/2035		5135.27	10/21/2035
3	161616	10/21/2035		5143.17	4/22/2035
4	162043	3/25/2035		5165.26	10/15/2035
5	163895	5/5/2035		5173.54	3/25/2035
6	164233	3/31/2035		5176.58	10/14/2035
7	165321	9/30/2035		5190.28	3/26/2035
8	165997	10/14/2035		5201.79	4/29/2035
9	166828	10/27/2035		5225.23	10/22/2035
10	166891	10/28/2035		5228.14	4/23/2035

For purposes of my analysis, I selected the following dates: October 14, 2035, for DEC; and April 15, 2035. Next, I used the Companies' hourly EnCompass SPS production profile curves for the same dates as the low load events. I performed a simplifying assumption and assumed all solar will be paired with battery storage. Performing this simplifying assumption masks the real impact of solar without storage. The results of my analysis (with the simplified assumptions) are as follows.

DEC:



DEP:



Q. Please explain the results of your Lowest Load Day Event graphs.

A. The uppermost line is the gross load, the total load each utility must serve before solar generation is added to the system.

The horizontal line is the LROL, which factors in two nuclear refueling outages in DEC and a single nuclear refueling outage in DEP.[35] I used a general proxy of a 1,200 MW unit to account for the N-1 contingency discussed above.

Given the uncertainty of when or how battery storage would “charge” and absorb excess energy off the system, I graphed both lines to reflect system conditions if the batteries were to charge or if the batteries did not charge, illustrating the potential upper and lower bounds of how system operators would need to respond during a low load event.

I manually “turned on” the battery when the net load fell below the LROL limit and then “turned off” the battery when the net load went above the LROL limit. I determined the hours between the “on” and “off” stage and levelized the battery storage output over that period. Again, this analysis is not a perfect reflection of how battery storage will be dispatched, even if operators had perfect foresight to have all batteries depleted and ready for charging at the time of optimum grid status.

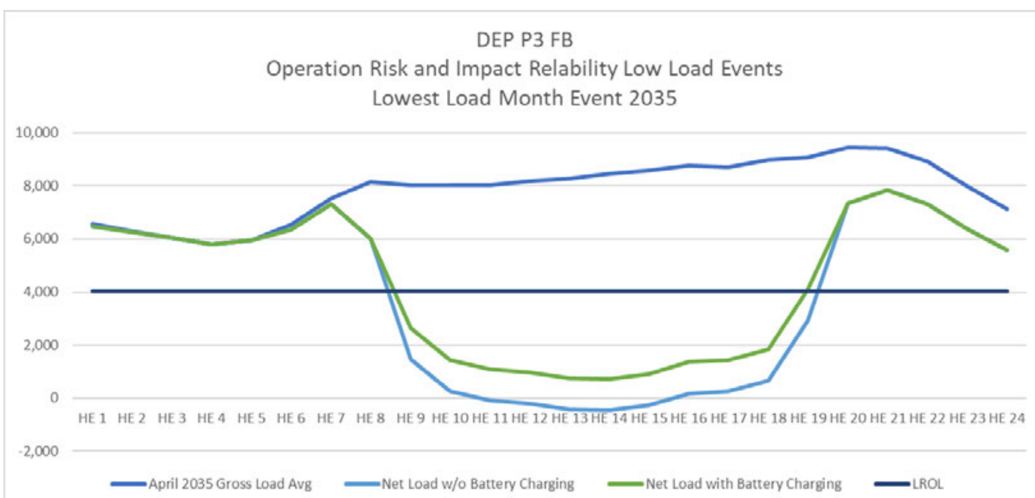
With regard to DEC, it is clear that without battery charging, the system would breach the LROL “floor,” but implementation of battery charging

[35] DEC has a larger nuclear generation fleet and therefore is likely to have a higher occurrence of simultaneous nuclear refueling outages.

would prevent DEC system operators from needing to reduce nuclear power plant output.

The results for DEP, on the other hand, are extremely alarming. In a worst-case scenario, not only would DEP need to curtail all nuclear power output but would also need to find a buyer to export energy, potentially even at negative pricing (i.e., paying buyers to take the energy, a.k.a. “dumping”) given the excess.

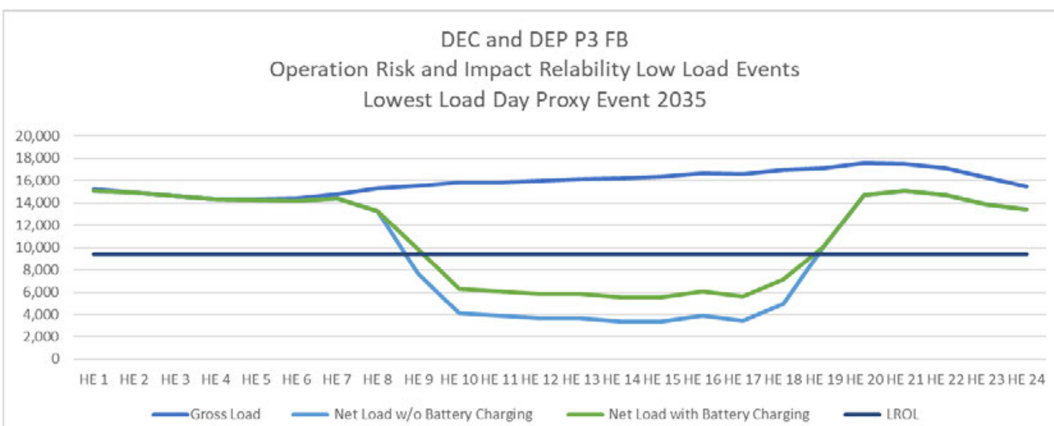
Due to the extreme impacts of the DEP case, I evaluated the DEP system over the entire month, using the same methodology described above and matched both hourly loads and solar generation in the same hours.



The results of a Lowest Load Month in DEP’s service territory are not that different from the Lowest Load Day. It is also noteworthy that I combined the DEP East and DEP West Balancing Areas in all of these examples in order to add additional load. Stated differently, this analysis, if done more precisely, would look worse with the DEP East Balancing Area as a standalone case. DEP East would have less load, while the total solar installed would be virtually unchanged (there are minimal solar resources in DEP West compared to DEC East), not to mention all of the pre-existing solar PV not paired with storage.

While system operators must resolve their individual Balancing Areas, I also analyzed a DEC and DEP combined system. The graph below shows the current day dispatch of non-firm energy between the Companies as well as a potential outcome if the Companies were to merge. Given that the two low load periods between DEC and DEP occur in different months, I performed a simple average of the SPS hourly contribution and added the loads together. This analysis was to emulate a potential "shoulder day proxy."

DEC and DEP:



The addition of DEC load "helped" DEP but not enough to avoid curtailments. On this particular day, either solar must be curtailed or about half of the combined DEC and DEP nuclear fleet will need to be curtailed or the entire nuclear fleet reduced to half power, notwithstanding the impacts to other generation units and cycling considerations.

The Commission must understand that larger curtailments of solar or impacts to the nuclear fleet are no longer possibilities; they are now a given.

Q. Based upon your discovery, did the Companies raise any concerns about this reliability event, either low load or LROL?

A. Yes. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

The Companies' own analysis was more detailed than mine, and they factored in additional resource generation profiles, not just solar. The following graphs step through the changes from 2032 to 2035 to 2038 using Duke's P3 FB assumptions.

[BEGIN CONFIDENTIAL]

[redacted]

[redacted] **[END CONFIDENTIAL]**

Q, Previously, you discussed load ramp constraints. Please elaborate.

A. Referencing Duke's confidential LROL graphs above is informative for determining the ramp rate.

Listed below is the Duke 2035 LROL graph from above but with a narrower set of hours. **[BEGIN CONFIDENTIAL]** [redacted]

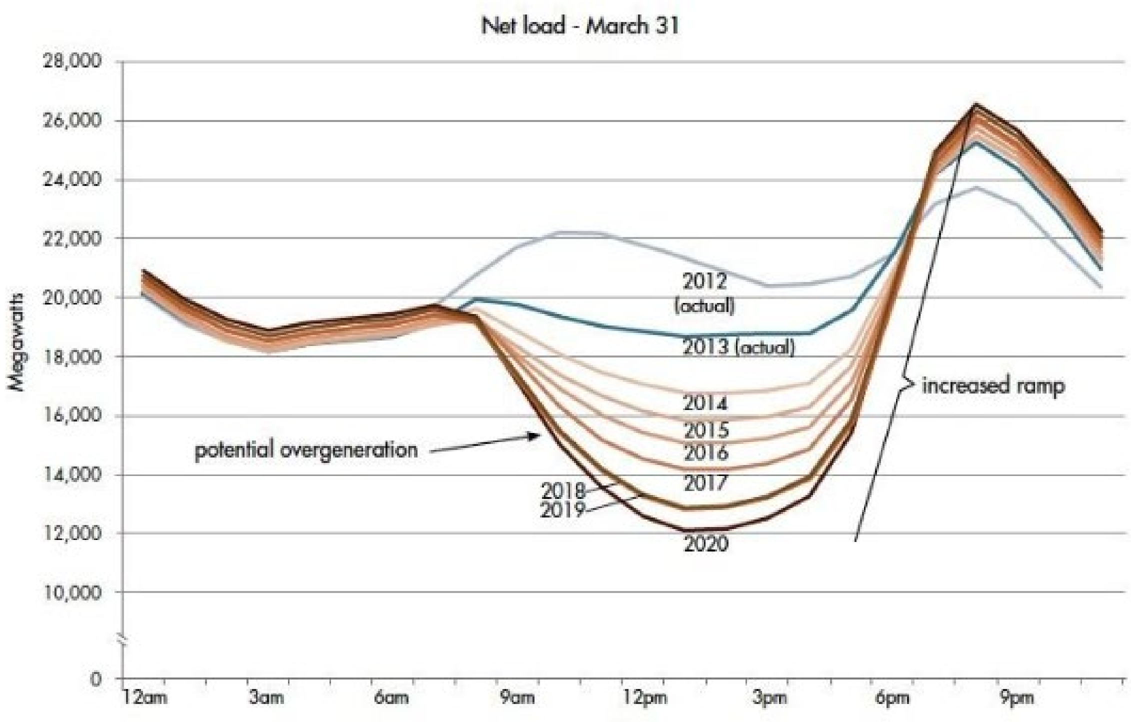
[redacted]

[redacted]

[END CONFIDENTIAL]

The ability to have a controlled ramp, which includes turning on and even turning off this magnitude of generation assets, is likely to create additional challenges for system operators, leading to difficulties maintaining grid reliability. This observation is heightened when individual utility balancing areas are interconnecting solar generation in amounts that are not commensurate with their respective loads nor in consideration of their present solar-to load ratios (i.e., solar penetration to load). To the extent that solar is located in the DEP East balancing area because it is “cheaper” or because the design of the DEP transmission system makes it more robust for supporting larger quantities of solar interconnections than the DEC transmission system, does not justify DEP ratepayers shouldering a disproportional share of the risks and costs for statewide carbon reduction compliance.

The general relationship of load and ramping illustrated in the confidential graphs above is similar to the U.S. DOE Solar Energy Technologies 2017 article that estimated incremental ramping by 2021.[36] Listed below is a 2013 chart published by the California Independent System Operator (CAISO) that illustrates the ramping requirements.

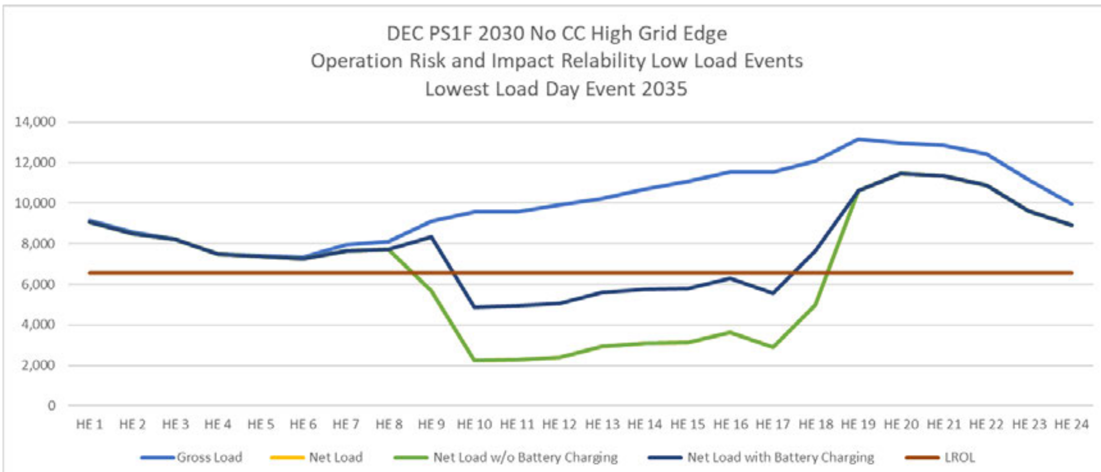


[36] https://www.energy.gov/eere/articles/confronting-duck-curve-how-address-over-generation-solar-energy

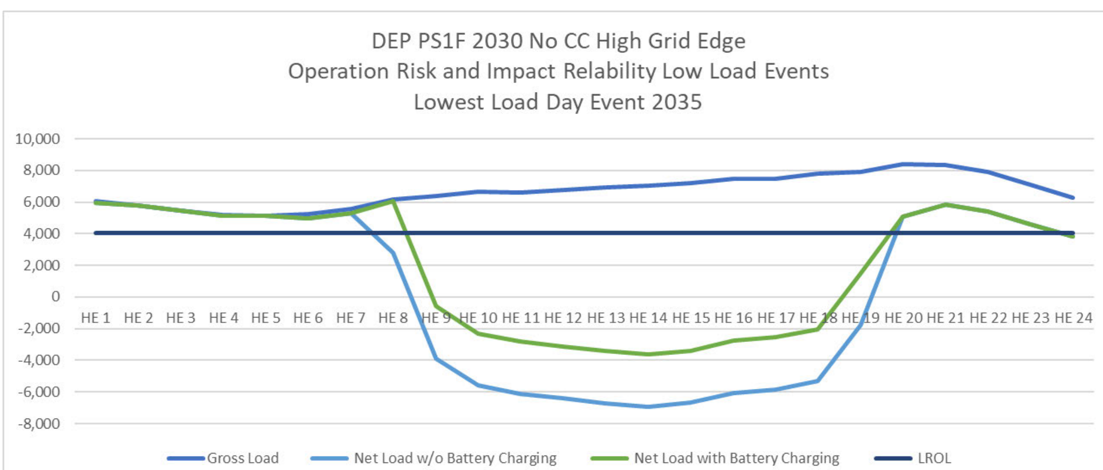
Q. Earlier in your testimony you referenced a "no combined cycle case" that enabled more solar and solar plus storage annual interconnections. Did you perform a similar lowest load day analysis for this portfolio?

A. Yes. The results for each utility are shown below.

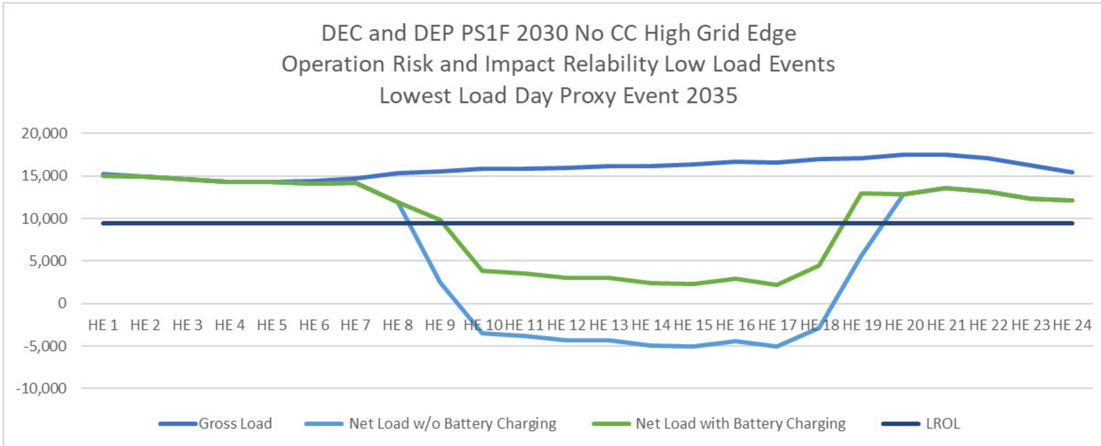
DEC:



DEP:



DEC and DEP:



Q. Please describe the takeaways from these graphs when using a higher amount of solar interconnection.

A. Ultimately, the reliability of the electric system defaults back to the responsibility of the Companies. While I am not a system operator, the above graphs do illustrate *an alarming situation* involving curtailments, cycling of massive generator units, and responding to dynamic system conditions in an unprecedented manner that will likely jeopardize system reliability. A balanced approach of resource additions per utility service area is critical to mitigate the identified risks.

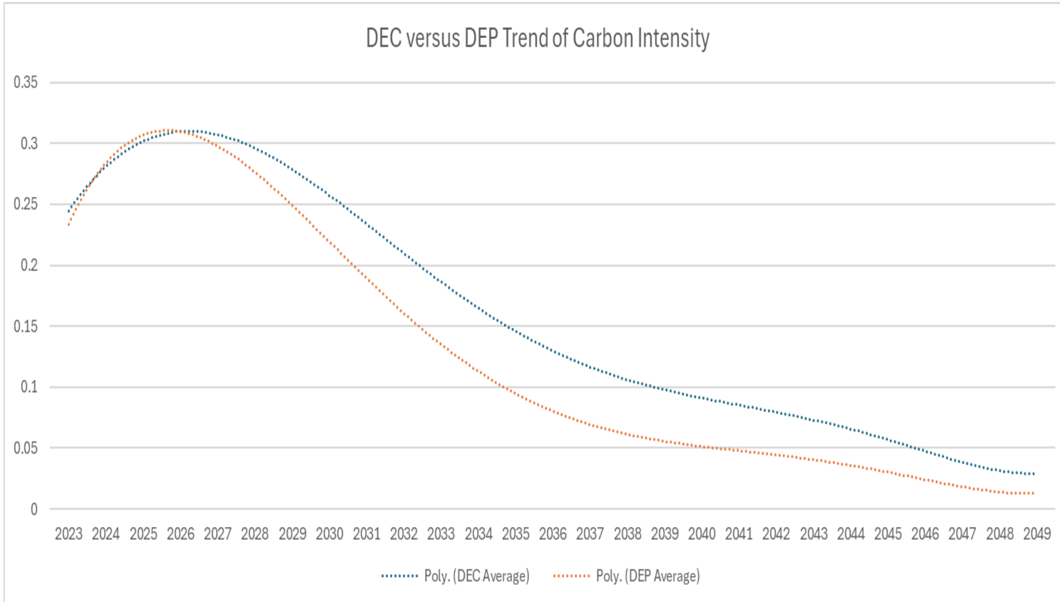
X. CARBON INTENSITY

Q. Please describe carbon intensity and why you evaluated it.

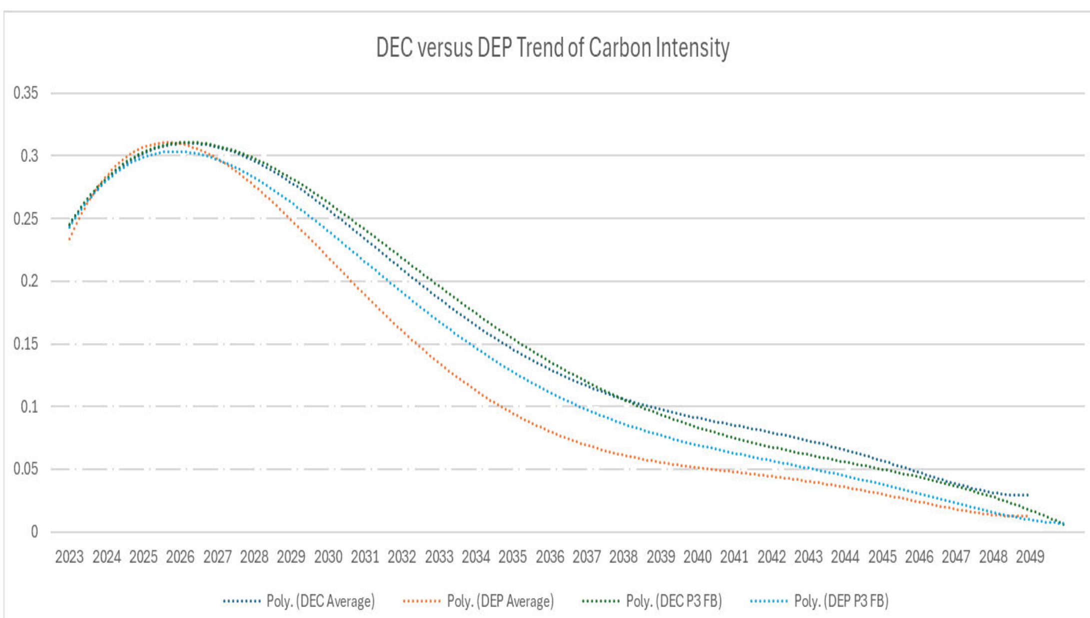
A. For purposes of my testimony, I sought to track the modeled projections of carbon intensity for each of the Companies on a short ton of CO_2 emitted per MWh generated metric. I believed that trending this data would give insight as to the carbon reduction progress each individual utility is making and whether a certain portfolio achieves overall less CO_2 emissions than another. This analysis will allow the Commission to consider the overall net reductions of CO_2 per portfolio and/or sensitivity given the amount of incremental load that has been projected by the Companies.

Q. Please provide a summary of your evaluation.

A. My analysis of carbon intensity for DEP and DEC reveals a notable difference in environmental impact. DEP's carbon footprint is currently less intense than that of DEC, with this gap expected to widen between 2026 and 2037 due to DEP reducing its carbon intensity at a more rapid pace. This trend suggests that DEC's strategy relies in part on DEP's generation assets to achieve total CO_2 reductions, highlighting a potential equity issue in the distribution of environmental efforts (and costs) between the two utilities. The graph immediately below, which averages Duke's P2 FB and P3 FB portfolios along with multiple Public Staff sensitivities, serves as a visual representation of this disparity, illustrating the separate trajectories of DEC and DEP in terms of carbon intensity. Such insights are crucial for understanding the dynamics of energy transfers and the equitable distribution of responsibility for reducing carbon emissions within the two Companies.



The following graph compares the average carbon intensity, shown above, to the Companies' P3 FB portfolio. The results of this graph show that the Companies' P3 model runs are more carbon intensive than the average of multiple portfolios.



My evaluation also tracked the total CO_2 emissions per portfolio in years 2033, 2035, 2038, and 2050 over different Duke and Public Staff models.

		Total Cummaltive CO2 Emissions (M Short Tons)			
		2033	2035	2038	2050
DEC and DEP	D P2 FB	488	540	604	728
	D P3 FB	520	582	653	786
	PS1F 2032	478	522	585	726
	PS1F 2034	510	559	619	751
	PS1F 2034 Limit OnSW	511	561	624	762
	PS1F 2034 Accel SMR	512	561	622	756
	PS1F 2034 Shared Capacity	507	557	618	750
	PS1F 2034 SC CC	519	575	647	813
	PS1F 2034 EPA 40% CC Limit	527	577	637	772
	PS1F 2035	517	572	636	768
	PS3F_2037_Force DEP CC, 2035 OffSW, EPA 40% CF	544	618	693	818

The results shown in the table above indicate the general trend of higher CO_2 emissions per year for certain portfolios. The darker blue equates to less carbon emittance, transitioning to opaque, and then more carbon intensive portfolios, which are darker red.

XI. HYDROGEN PILOT PROGRAM

Q. Given the recent EPA CAA Rule and the cost uncertainty of your proposed future carbon regulation proxy price, do you have recommendations for the Commission to consider in these areas?

A. Yes. Due to the uncertainty around the use of onsite hydrogen generation and its utilization in natural gas generation plants in the Carolinas, it is reasonable at this time for Duke to propose a pilot project. The Public Staff is willing to work with Duke on the scope, length, and potential rate impacts of a proposed pilot.

Q. Mr. Metz, have you proposed that DEC come forward with such a pilot project before?

A. Yes. In my MYRP testimony in Docket No. E-7, Sub 1276, I recommended that DEC propose a more specific hydrogen pilot program instead of the more generic MYRP project that lacked any type of economic justification.

Q. What key factors or details should be in the pilot program?

A. Ultimately, the key factors and details will be heavily dependent on the EPA's final rule for new natural gas plants and how the State enacts its proposed plan of compliance. To obtain insight into technology implementation, project scheduling, and risk impacts to ratepayers, the Companies should produce feasibility studies and high-level cost estimates to blend up to thirty percent hydrogen for both CTs and CCs with scaling analysis to higher amounts. Incorporation of project costs into DEC's pending Marshall CT design for example, or any equivalent first-to-be-built advanced class CTs, could prove beneficial. Design and procurement on the front end of a project can result in longer-term cost savings for both the utility and its ratepayers.

The exact parameters of this feasibility study for hydrogen blending would need to be worked out with the Companies, as developing a defined pilot project was beyond the scope of my investigation in this case. However, such a feasibility study should include, but not be limited to, (1) PEM technology, (2) co-located carbon-free generation to produce hydrogen, (3) maximization of federal tax credits on behalf of ratepayers, (4) analysis of PEM generation's abilities to mitigate system reliability events with ramp constraints and/or mitigate lowest reliable operating limits (LROL), and (5) analysis of the impacts of not cycling baseload nuclear power generation.

I request that the Companies provide in rebuttal their opinion of the potential value of implementing such a pilot, or an alternative, to explore hydrogen blending.

Finally, I request that the Commission direct the Companies and the Public Staff to work together to identify any areas of agreements on a potential pilot project of this type, and to the extent that either party disagrees on the scope, to file a comprehensive list of the areas of disagreement with the Commission within six months of issuance of the Commission's final order in this proceeding.

XII. RATE DISPARITY

Q. Please summarize your concerns on the DEP versus DEC equity issues raised throughout your testimony.

A. My concerns regarding the long-term impacts on ratepayers of the increasing volume of energy transfers between DEP and DEC are significant. The energy infrastructure and the associated costs required for this transfer of energy have implications on both the future reliability of service and the financial burden on customers. Thus, it is essential that the costs related to such transfers are managed equitably to ensure that no single group of ratepayers bears a share of the costs to serve another group of customers.

Q. Do you consider it reasonable for DEP customers to pay costs to serve the energy needs of DEC customers?

A. No, particularly when the situation is so one-sided. If DEC and DEP were to have near equal transfers of energy to and from each other throughout the year or even over a couple of years, and the total cost of the energy was roughly equivalent, one might consider that result to be reasonable and just. However, our investigation shows that is neither the current reality nor forecasted to be a future reality; it is a very one-sided situation. DEC customers are the beneficiary of lower rates due to generation and transmission, built in DEP territory and paid for by DEP customers, to serve the energy needs of DEC customers.

Q. Does the Commission have the authority to take into consideration the overall impacts to DEP customers?

A. While I am not an attorney, based upon the plain language of HB 951 and Chapter 62, I believe that not only does the Commission have the authority to consider discrete impacts to DEP customers, the Commission is required to do so. Chapter 62 grants the North Carolina Utilities Commission significant discretion in shaping the state's approach to utility resource planning and ratemaking while mandating that rates be just, reasonable, and nondiscriminatory. The Commission's authority to continually update the Carbon Plan reflects a dynamic approach, allowing adjustments as new information and technologies become available. Moreover, the Commission's rate-setting power is crucial to ensuring that costs are allocated fairly among different customer classes and utilities.

The concerns about equitable cost distribution raised in my testimony and the Public Staff in prior proceedings highlight one of the complexities of rate design, namely the importance of adhering to cost causation principles. One of the most fundamental cost causation principles in the utilities sector is that rates should be proportional to the cost of service provided. This principle ensures that no single group of ratepayers is disproportionately burdened with the costs of providing service necessary to ensure a functioning and reliable grid. Equitable cost causation maintains fairness and economic efficiency through ensuring each customer pays the costs associated with providing them utility service. While this principle has traditionally been applied to ensure rate equity between different classes of customers under a single utility, the cost causation principle is equally necessary to ensure that ratepayers of one utility do not bear the costs caused by another utility.

Q. Does the Public Staff have concerns about equity and rate disparities between DEC and DEP?

A. Yes. This point was made in the 2022 Carbon Plan proceeding by witness James McLawhorn, and the concern has only grown. The scale of the disparity between DEC and DEP continues to grow, and urgent attention is required before electric rates in DEP far exceed those in DEC. The disparity is driven by the growing amount of generation located in DEP territory to serve DEC load requirements and is further complicated by the transfer of energy from DEP to DEC given the complexities of each utility's load forecasts and rate disparities.

Q. Please provide examples of when the issues of rate disparities between DEC and DEP and appropriate allocation of costs based upon causation have been raised and what actions the Commission requested to resolve the issues.

A. Members of the Public Staff's Energy Division raised these concerns during the 2022 Carbon Plan stakeholder discussions and in testimony, essentially requesting that the Companies honor their 2012 merger commitment to create a single utility. In recent rate cases for DEC and DEP, the concept of a transmission cost allocation adjustment to account for DEC's use of DEP's grid to access low carbon power developed in DEP was proposed by the Public Staff, agreed to in a comprehensive settlement between the Companies and the Public Staff, and approved by the Commission.

In the Commission's 2022 Carbon Plan Order, the Commission stated:[37]

> Based upon the foregoing and the entire record in this proceeding, the Commission finds that it may be appropriate

[37] 2022 Carbon Plan Order, at 128.

> for Duke to pursue a merger of DEC and DEP according to the timeline set forth in the panel testimony of Duke witnesses Peeler and Bateman; however, the Commission will not prematurely judge the prudency of such a merger proposal and will only consider such when an application is properly before the Commission. Until such a time, the Commission directs Duke to take reasonable steps to mitigate further exacerbation of the rate disparity between DEC and DEP attributable to the Carbon Plan by presenting solutions where appropriate, including but not limited to in its pending general rate case applications.

Q. Based upon your review in this proceeding, do you conclude that the portfolios filed by both the Companies and the Public Staff would increase the rate disparity that already exists?

A. Yes. Duke has not proposed any mitigation in its CPIRP nor has it taken reasonable steps in this CPIRP to mitigate further exacerbation. Its only officially proposed strategy is to pursue the merger of DEC and DEP.

Q. Are DEP customers disproportionately bearing the costs of implementing a Statewide Carbon Plan?

A. Yes.

Q. Would it be fair to classify your concerns as more appropriate for addressing in a general rate case?

A. To an extent, yes. Ratemaking issues, including equitable cost allocation and rate design, are typically reviewed within the context of a general rate case. However, establishing one resource expansion plan for both utilities requires the evaluation of each individual utility's needs and whether the plan will lead to adequate, reliable, and economical utility service. The magnitude of the decisions being made in this case is different than in the previous CPIRP. The impacts of requiring multiple actions on longer lead time items, the nature of the Companies' proposed request for relief, and the recent CAA Rule all point to longer term impacts to ratepayers flowing from the decisions made in this case. It is imperative that the Commission be cognizant of these issues as it renders a decision in this docket.

Q. What recommendations do you have to address your concerns?

A. Before making my recommendations, I acknowledge that these recommendations are complex, and they will likely require additional discussion with the Companies and refinement.

A transmission cost-sharing mechanism is one approach to distribute the financial responsibilities associated with capital investments and operational expenses, and one such mechanism was approved by the Commission in the most recent DEP and DEC general rate cases. Such a mechanism should comprehensively cover the capital requirements for new investments in generation and transmission infrastructure but exclude investments in the distribution system. Additionally, it should account for the ongoing operation and maintenance costs that arise from utilizing another utility's systems.

Duke should propose a cost-sharing mechanism in rebuttal testimony to allow for a detailed examination by the parties and the Commission. Should the Companies fail to present a cost-sharing proposal, the Commission should order Duke to develop and propose an equitable cost-sharing mechanism within six months of the CPIRP order. Duke should submit monthly progress reports to ensure transparency until the final proposal is filed with the Commission. The cost-sharing mechanism should include, but not be limited to, the following:

- The cost-sharing mechanism should be applied to the bill impact analysis of both P3 FB and PS1F 2034. The Companies should provide an updated bill impact analysis with the cost sharing in rebuttal testimony.
- The cost-sharing mechanism should be based upon the annual energy transfers, subject to further analysis and discussion between the Public Staff and the Companies.
- The cost-sharing mechanism would terminate in the first general rate case that allocates system costs of the merged DEP and DEC utilities.
- The cost-sharing mechanism should only affect the NC Retail allocation.
- No additional DEP CPCNs should be submitted by the Company for Commission approval without inclusion of a proposed cost-sharing mechanism and appropriate bill impact analysis for all DEP and DEC retail customers in North Carolina.

Q. Why not wait until the proposed merger of DEC and DEP is completed?

A. At this point, the merger is merely a concept and we must plan to meet the Carbon Plan based upon today's situation where DEC and DEP are separate utilities. While the Public Staff expects the utilities will successfully merge, there are many uncertainties. The merger must be approved by this Commission, the South Carolina Public Service Commission, and FERC. No merger proceeding has been initiated before any of these regulatory bodies. We do not know the timeframe these regulatory bodies will use to consider the request or the components of their decision. Hinging all solutions on the expectation that the merger will be approved by all regulatory bodies in a timely manner is not a plan, particularly as commitments to major investments are being made today. The Companies must look for a way, today, to mitigate the impact of both current and future cost disparities in the event the merger does not take place.

Q. Would a cost-sharing mechanism, or an equivalent alternative of the concept you proposed above, comply with the Commission's final order in the 2022 Carbon Plan proceeding?

A. Yes.

XIII. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your conclusions and recommendations.

A. The comprehensive analysis conducted by the Public Staff has culminated in a robust proposal that provides a diversified approach to new generation assets. This planning strategy underscores the importance of not pursuing resource procurement indiscriminately, but rather with prudent oversight and adaptable measures in place. The Companies' proposed offshore wind ARFI, however, presents a degree of ambiguity that could dampen the enthusiasm of offshore wind lease holders, suggesting the need for a more defined framework. The establishment of a new docket dedicated to offshore wind procurement could foster deeper exploration and discourse on this front. Moreover, the engagement of an independent evaluator would enhance the structural integrity, oversight, and transparency of the procurement process. My testimony delves further into the synergies between new nuclear development and offshore wind, emphasizing the necessity of updated cost assessments for offshore wind, particularly if the acceleration of SMRs is not feasible within the timeframe of the projected energy load forecast. This holistic view advocates for a balanced and forward-thinking approach to energy and capacity procurement, ensuring that strategic decisions are made with a comprehensive understanding of the interplay between various energy sources and their long-term implications on the energy landscape.

The integration of new generation assets must be balanced with the practical limitations of system capacity and the need for maintaining reliability. The inclusion of a transmission transfer rate is crucial for evaluating the economic viability of future resources, especially considering the disparities in generation assets and total utility service between DEC and DEP. The analysis indicating significant power transfers from DEP East to DEC highlights the necessity for equitable cost distribution among ratepayers, particularly in light of the targets set forth in HB 951. Furthermore, the recent EPA CAA Rule introduces additional complexities, particularly concerning the future of natural gas additions and the impending retirement of coal assets. It underscores the importance of strategic planning and the potential need for CAA Rule mitigation in future CPCN filings, ensuring compliance while minimizing the financial impact on customers. The evolving regulatory landscape necessitates a careful examination of individual utility rate impacts and a concerted effort to manage the clean energy transition.

There is a strong interrelationship between replacing existing coal generation with CCs and CTs in the near-term planning horizon. Also, to the extent that a CC is built despite modeling showing it to be uneconomic in one utility’s service area versus the other utility’s service area where modeling economically selected the resource, the future siting of combustion turbines is also impacted. Thus, a ripple effect occurs when evaluating the need for and reasonableness of CPCNs, while, at the same time, the present modeling approach appears to be closer to joint utility planning versus independent utility planning. This ripple effect compounds the equity issue arising between DEP and DEC ratepayers.

I request that Duke complete a SERVM analysis on the Public Staff's proposed PS1F 2034 at a minimum. The results of the SERVM analysis should be reported in the Companies' rebuttal testimony.

The Companies have not provided sufficient support for their plan to seek five natural gas CC CPCNs prior to issuance of the next Commission-approved CPIRP, notwithstanding further changes in the load forecast resulting in additional incremental load. This conclusion is supported in part by the recent EPA CAA Rule. The Companies have not presented a plan indicating how they will comply with the CAA Rule in their primary portfolio, or even for the two active natural gas CPCNs at Marshall and Roxboro.

The 2023 CTPC Public Policy results highlight significant challenges and opportunities within the electrical transmission system. The findings underscore the necessity for a comprehensive transmission plan that aligns with the projected load forecast and the integration of additional generation assets. The 2023 CTPC report revealed that approximately 1,100 miles of the transmission system experienced strain (overloads), necessitating an estimated $2.6 billion investment to address the overloads. Moreover, six utility-to-utility interties were also affected by these overloads, indicating a broader impact on the grid's stability. However, the 2023 CTPC results did not fully account for the additional generation needed for the Companies' updated load forecast, thus it is likely that even more upgrades will be required in the coming years. In response to these findings, it is imperative that future CPIRPs incorporate a robust transmission plan that can accommodate the proposed portfolio of the Companies. This approach would ensure a more integrated planning process, moving away from the current method, which seems antiquated under such a dynamic buildout of generation resources. Such a plan would not only address the immediate needs identified in the 2023 CTPC study, but also provide a resilient framework to support the evolving demands of the electrical transmission system.

The Companies have not demonstrated that the initial and first supplemental RZEP 2.0 projects resolve a known reliability issue or that failure to proactively build out these projects would materially impair future interconnection of resources since the upgrades were estimated to take appropriately four years to complete. Four years of interconnection upgrades are in line with solar procurement cycles and expected commercial operation. In addition, the Companies' request for relief requested that the Commission approve the RZEP 2.0 projects. I have explained why it is not necessary for the Commission to approve these projects and the risks to customers if the Commission were to approve the Companies' request.

My testimony went into significant detail to explain the aggregated results of multiple Public Staff and Company portfolios and modeling sensitivities. I demonstrate to the Commission the resource selection for each utility and the respective costs.

I identified a heightened concern around future system reliability and what actions should be taken to inform future CPIRPs. The Companies will no longer need to evaluate summer and winter peaks, but rather low load conditions, which occur multiple times a year during shoulder seasons (i.e., spring and fall).

The integration of significant solar energy into the grid is a complex issue that requires careful analysis to ensure system reliability. A comprehensive study, as suggested, would involve assessing the theoretical maximum solar capacity that can be added annually per utility, while also evaluating the potential for curtailments—instances where solar energy generation exceeds demand or transmission capacity. This study would need to consider the role of battery storage or other energy storage solutions in mitigating these curtailments. It is crucial to understand how much storage will be required to balance the grid during periods of excess generation and determine if storage is being added at a pace commensurate with solar. Additionally, identifying risk factors associated with high levels of solar penetration, such as grid stability and the ability to meet peak demand without relying on curtailments, is essential. Collaborative efforts between the Public Staff and the Companies can ensure that the study's scope is well defined and that the deliverables provide actionable insights for integrating solar energy effectively and reliably.

My analysis demonstrated the carbon intensity for each utility. The analysis showed the general trends of decreasing carbon intensity as well as the aggregated total CO_2 emissions per portfolio.

I recommend that the Companies propose, and the Commission direct, a hydrogen pilot project feasibility study with the scope including, but not limited to (1) PEM technology, (2) co-located carbon-free generation to produce hydrogen, (3) maximization of federal tax credits on behalf of ratepayers, (4) analysis of PEM generation’s abilities to mitigate system reliability events with ramp constraints and/or mitigate lowest reliable operating limits (LROL), and (5) analysis of the impacts of not cycling baseload nuclear power generation. The feasibility study and future cost scoping would inform future CPIRP filings.

Q. Does this conclude your testimony?

A. Yes.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

DUSTIN R. METZ

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

I have over twelve years of combined experience in engineering, electromechanical system design, troubleshooting, repair, installation, commissioning of electrical and electronic control systems in industrial and commercial nuclear facilities, project planning and management, and general construction experience. My general construction experience includes six years of employment with Framatome, where I provided onsite technical support, craft oversight, and engineer design change packages, as well as participated in root cause analysis teams at commercial nuclear power plants, including plants owned by both Duke and Dominion. I also worked for six years for an industrial and commercial construction company, where I provided field fabrication and installation of electrical components that ranged from low voltage controls to medium voltage equipment, project planning and coordination with multiple work groups, craft oversight, and safety inspections.

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

Technology	Duke's NTAP MW	Public Staff NTAP MW	Amended Petition Request ($M)	Public Staff Recommendations:
Solar	6,460 by 2031	Minimum: 6,700 by 2031	$ -	• **2024 Procurement targeting 1,585 MW is under Commission review.** • **2025/2026: Procurements targeting 2,940 to 3,700 MW total solar and SPS** (approx. 2029-2030 in-service date). Significantly larger proportion of SPS than solar-only (between 50% and 85% of solar capacity should be SPS; larger capacity ratio and durations should be considered). • If future RFPs procure less SPS than recommended by the Public Staff, the Companies should provide an update in the Independent Evaluator reports that describe the shortfall and propose remedies to maintain system reliability. • The Companies should propose future transmission projects to the appropriate transmission working group (CTPC or SERTP), while updating the Commission of the progress in future CPIRPs. • The Companies should develop and or procure solar, especially in the DEC service area, with target amounts to be set in the solar procurements. Until the Companies have completed a merger, they should reasonably strive to locate at least 40% of future solar resources in the DEC service area in order to mitigate future transmission congestion in the DEP service area and address cost allocation and equity concerns. • Prior to the Companies next CPIRP, the Companies should provide a report on the comprehensive study on system operation and reliability to address concerns of LROL, ramping, and quantify the amount of future solar procurements that are likely. The Companies next CPIRP should incorporate findings and or limits from this report.

Technology	Duke's NTAP MW	Public Staff NTAP MW	Amended Petition Request ($M)	Public Staff Recommendations:
Battery Storage	2,700 by 2031	Minimum: 2,700 by 2031	$ -	• 2024 to 2026: Develop and study additional 475 MW of stand-alone battery storage incremental to 2022 NC Plan. • 2024 to 2026: Target procurement of at least 1,450 MW of SPS (1,110 MW of SPS incremental to 2022 NC Plan).
Onshore Wind	1,200 by 2033	Minimum: 600 MW by 2031 1,050 MW by 2032 1,800 MW by 2033 Maximum: 2500 MW by 2033	$65.6	• Approve Amended Petition development costs and activities, with conditions. • The final procurement targets should be updated once the Companies are able to develop more accurate cost estimates and obtain data to determine operational characteristics (output profile, capacity value). Future CPIRP cycles should incorporate this information, in parallel with early-stage joint development, to check and adjust. • The Companies shall file report in the next CPIRP summarizing onshore wind development, updated cost information and operational assumptions, and a comparison of projected LCOE to the resource modeled in the CPIRP. • At least 33% of the target quantity should be located in DEC, barring technological, commercial, or economic justifications. • The Companies should seek to expand the sites reviewed and developed for cost-effective onshore wind, particularly in DEC's territory.
CT	1,700 by 2032	849 MW by 2030	$ -	• Public Staff identified the interrelationship of future combined cycles and combustion turbines. Absent a further review of EPA 111(b) impacts, a set number of MWs cannot be determined at this time. • The Companies should file for CPCNs as needed, and future CPCNs should be filed to meet project construction schedules.

Technology	Duke's NTAP MW	Public Staff NTAP MW	Amended Petition Request ($M)	Public Staff Recommendations:
				• CPCNs should be required to address compliance with EPA's 111(b) rules. • The results of SERVM would need to be evaluated and the minimum target adjusted as needed to maintain or improve system reliability. Companies evaluate the reliability of the Public Staff's base portfolio and respond in rebuttal if additional CTs are needed.
CC	6,800 by 2033	<u>Minimum</u>: 1,359 MW by 2030	$ -	• Combined Cycles have more stringent restrictions in EPA 111(b) rules than combustion turbines. **CPCN applications shall demonstrate that the Companies have a reasonable compliance plan in place.** • The Companies require a glide path to properly manage the retirement of approximately 8.5 GW of coal generation while maintaining reliability. • **Public Staff's modeling supports the economic selection of a limited number of combined cycles** to aid in the retirement of the existing coal fleet and meeting new load, subject to obtaining fuel supply on future natural gas firm capacity. • Public Staff's modeling suggests that it may be economic to locate CCs in DEC, not DEP. • Public Staff does not support Duke's proposal to file CPCNs for five combined cycles by 2026 due to concerns about fuel supply, EPA 111(b) regulations, large economic load materialization, and the risk of stranding these assets, if they are not reviewed in the 2025 CPIRP. • The Companies should report in future CPIRP filings on the progress of securing firm capacity for Company proposed CCs 3 through 5 and provide an analysis of the materialization rate of large economic load customers.

Technology	Duke's NTAP MW	Public Staff NTAP MW	Amended Petition Request ($M)	Public Staff Recommendations:
Pumped Storage Hydro	1,834 by 2034	1,834 by 2034	$165	• Approve Amended Petition development costs. • DEC to provide updates on the proposed project in the next CPIRP, or, if appropriate, before the next CPIRP. • If estimated costs increase 15% or more from the 2023 CPIRP filing prior to the next CPIRP, DEC shall inform the Commission of the impact and a revised capacity expansion plan with updated cost information. • Public Staff accepts the Companies modeling approach and economic analysis supporting Bad Creek II. Similar analysis should be completed in the next CPIRP with the most up to date cost information.
Advanced Nuclear	600 by 2035	Minimum: 300 MW by 2034 600 MW by 2035 1,200 MW by 2036	$439	• Approve the Companies Amended Petition development request. • Based upon the PVRR reductions associated with higher SMR deployment, the Companies should progress with SMR development/deployment in the Carolinas as long as the cost estimates used in Encompass stay within a reasonable range. • The Companies should provide annual updates on the progress of development efforts and significant regulatory developments, including a revised project schedule and cost estimate as progression occurs. • To the extent that the Companies cannot achieve the proposed pace or if the original schedule is untenable, the Companies should make plans to replace nuclear generation with other cost-effective low-carbon resources. • DEC territory should be prioritized for the location of the first three SMRs, unless factors arise that would cause a need for accelerated deployment in DEP service area.

Technology	Duke's NTAP MW	Public Staff NTAP MW	Amended Petition Request ($M)	Public Staff Recommendations:
Offshore Wind	2,400 by 2035	Target: 800 – 1,100 MW by 2034 2.2 – 2.4 GW by 2035	$1.4	• Approve Amended Petition to incur development costs. • The Companies should review their proposed schedule and **make reasonable efforts to bring the first block of offshore wind (between 800 and 1,100 MW, depending on costs) online by 2034 or 2035 at the latest, subject to required transmission upgrades.** • Future procurement of offshore wind shall not occur at "all cost" or "any cost." Prior to the ARFI, a confidential reference price or strike price should be created by the independent evaluator. • Bid packages provided in the ARFI that are within a reasonable range of the "strike price" should be considered for joint development agreements with Duke, taking into account the target quantity, cost, and timing. Lower than expected bid prices could merit higher target procurements, and vice versa. • The Companies should report on the ability for DEC to own or co-own these assets since the generation resource is located outside the immediate DEP service area.

Duke Energy Carolinas and Duke Energy Progress System Capacity

	SMR		Combined Cycle			Combustion Turbine			Total Solar			Battery paired with Solar			Battery Standalone			Onshore Wind		Offshore Wind	
Portfolio	2033	2038	2029	2033	2038	2029	2033	2038	2029	2033	2038	2029	2033	2038	2029	2033	2038	2033	2038	2033	2038
PS1F 2030 No CC High Grid Edge	-	1,800	-	-	-	1,698	3,393	3,393	8,550	21,375	25,762	5,560	9,680	9,680	3,100	6,100	6,100	2,100	2,100	1,100	1,100
PS1F 2032	-	600	1,359	8,155	8,155	2,508	4,628	4,628	3,750	12,750	21,937	1,880	7,460	7,460	1,700	5,100	5,100	2,100	2,100	3,300	4,400
PS1F 2034	-	2,100	1,359	4,077	6,796	849	1,269	1,269	2,700	11,700	18,112	1,040	3,260	4,300	200	400	1,400	1,800	2,250	3,300	4,400
PS1F 2035	-	2,100	1,359	6,795	8,155	1,273	1,269	1,269	2,700	11,700	19,912	1,040	2,660	5,700	200	200	2,000	1,350	2,250	-	2,200
PS1F 2034 Limit OffSW	-	1,500	1,359	5,436	8,155	849	845	845	2,700	11,700	21,262	1,040	6,040	7,960	200	3,100	4,100	1,800	2,250	1,100	2,200
PS1F 2034 No Tx Tfr Rate	-	1,800	1,359	4,077	5,436	849	1,269	1,269	3,000	12,000	19,387	1,200	4,220	5,660	300	300	1,500	1,800	2,250	3,300	4,400
PS1F 2034 No Tx Tfr Limit OffSW	-	1,800	1,359	5,436	8,155	849	845	845	3,000	12,000	21,562	1,200	5,160	6,640	300	2,600	3,600	1,800	2,250	1,100	2,200
PS1F 2034 Revised Low Load	-	1,500	1,359	4,077	6,796	424	420	420	2,700	11,700	18,112	1,040	4,120	5,160	300	300	1,300	1,800	2,250	-	1,100
PS1F 2034 Limit OnSW	-	2,100	1,359	4,077	6,795	849	845	845	2,700	11,700	18,112	1,040	4,580	5,620	200	300	1,300	1,800	2,250	3,300	4,400
PS1F 2034 Accel SMR	900	2,700	1,359	5,436	5,436	849	845	845	2,700	11,700	21,262	1,040	3,960	8,960	200	200	2,000	1,800	2,250	-	-
PS1F 2034 Force 2029 DEP CC	-	1,800	1,359	4,077	6,796	1,273	1,694	1,694	2,700	11,700	19,162	1,040	3,940	4,980	200	500	1,600	1,800	2,250	3,300	4,400
PS1F 2034 Shared Capacity	-	1,800	1,359	4,077	5,436	849	845	845	3,000	12,000	19,087	1,200	4,580	5,820	300	400	1,400	1,800	2,250	3,300	4,400
PS1F 2034 High Gas Cost	-	1,800	1,359	5,436	6,796	1,273	1,269	1,269	3,000	11,850	19,012	1,040	3,880	4,920	-	100	1,600	1,800	2,250	3,300	4,400
PS1F 2034 NoEIR	-	2,100	1,359	4,077	6,795	1,273	1,269	1,269	2,700	11,700	17,962	1,040	4,040	5,080	100	100	1,100	1,800	2,250	3,300	4,400
PS1F 2034 EPA 40%CC Limit	1,200	2,700	1,359	4,077	5,436	1,698	1,694	1,694	2,925	12,525	23,512	1,040	3,440	8,060	100	1,400	2,300	2,100	2,250	-	-
PS1F 2034 Low Battery Avail	-	1,800	1,359	4,077	6,796	1,273	1,269	1,269	2,700	11,700	19,162	1,040	3,880	5,340	100	300	1,300	1,800	2,250	4,400	4,400
PS1F 2034 NG Cap to 4 CC	-	1,800	1,359	4,077	5,436	849	1,269	1,269	2,700	11,700	18,637	1,040	4,520	5,560	200	600	1,600	1,800	2,250	4,400	4,400
PS1F 2034 SC CC	-	1,800	1,359	5,436	8,155	1,698	1,694	1,694	2,700	11,700	19,312	1,040	4,200	5,660	100	600	1,600	1,800	2,250	-	1,100
PS1F_2034_2035OSW	-	1,500	1,359	8,155	8,155	849	845	845	2,700	11,700	21,262	1,040	5,560	8,120	200	3,600	5,600	1,950	2,250	-	2,200
PS3F_2037_Force DEP CC, 2035 OffSW, EPA 40% CF	-	2,100	1,359	8,155	8,155	1,273	1,694	3,393	2,700	9,225	18,787	1,040	4,540	8,380	-	1,000	2,700	1,200	2,250	-	1,100
D P2 FB 2033	-	2,100	1,359	5,436	5,436	2,123	2,119	2,119	3,750	12,825	20,512	1,120	3,740	5,600	400	2,300	2,800	2,100	2,250	2,400	2,400
D P3 FB 2035	-	2,100	1,359	6,796	6,796	1,273	2,119	2,119	2,700	9,000	18,037	1,040	1,780	4,520	800	800	1,800	1,200	2,250	800	2,400

Docket No. E-100, Sub 190
Metz Exhibit 3

Duke Energy Carolinas Capacity

	SMR		Combined Cycle			Combustion Turbine			Total Solar			Battery paired with Solar			Battery Standalone			Onshore Wind		Offshore Wind	
Portfolio	2033	2038	2029	2033	2038	2029	2033	2038	2029	2033	2038	2029	2033	2038	2029	2033	2038	2033	2038	2033	2038
PS1F 2030 No CC High Grid Edge	-	1,800	1,359	-	-	(1)	3,393	3,393	1,050	9,375	12,002	400	4,160	4,160	-	2,100	2,100	450	450	-	-
PS1F 2032	-	600	1,359	8,155	8,155	2,508	4,203	4,203	1,500	5,175	9,302	760	2,880	2,880	-	2,400	2,400	450	450	-	-
PS1F 2034	-	1,800	1,359	4,077	6,796	(1)	420	420	1,050	4,725	8,852	400	1,340	1,540	-	100	100	600	600	-	-
PS1F 2035	-	2,100	1,359	5,436	6,796	424	420	420	1,050	4,725	8,852	400	1,360	2,280	-	-	-	-	600	-	-
PS1F 2034 Limit OffSW	-	1,500	1,359	5,436	8,155	(1)	(5)	(5)	1,050	4,725	8,852	400	1,940	2,740	-	600	600	150	600	-	-
PS1F 2034 No Tx Tfr Rate	-	1,800	1,359	4,077	5,436	(1)	420	420	1,050	4,725	8,852	400	1,420	1,620	-	-	200	600	600	-	-
PS1F 2034 No Tx Tfr Limit OffSW	-	1,800	1,359	4,077	6,796	(1)	(5)	(5)	1,050	4,725	8,852	400	1,940	2,540	-	900	900	150	600	-	-
PS1F 2034 Revised Low Load	-	1,200	1,359	2,718	5,436	(1)	(5)	(5)	1,050	4,725	8,777	400	1,460	1,660	-	-	-	150	600	-	-
PS1F 2034 Limit OnSW	-	2,100	-	4,077	5,436	(1)	(5)	(5)	1,050	4,725	8,852	400	1,860	2,060	-	100	100	600	600	-	-
PS1F 2034 Accel SMR	900	2,100	1,359	4,077	4,077	(1)	(5)	(5)	1,050	4,725	8,852	400	1,880	3,480	-	-	100	150	600	-	-
PS1F 2034 Force 2029 DEP CC	-	1,800	1,359	2,718	5,436	(1)	1,694	1,694	1,050	4,725	8,852	400	1,380	1,580	-	200	200	450	600	-	-
PS1F 2034 Shared Capacity	-	1,800	1,359	4,077	5,436	(1)	(5)	(5)	1,050	4,725	8,477	400	1,860	2,060	-	100	100	600	600	-	-
PS1F 2034 High Gas Cost	-	1,800	1,359	5,436	6,796	(1)	(5)	(5)	1,350	5,025	8,852	400	1,180	1,380	-	-	-	150	600	-	-
PS1F 2034 NoEIR	-	2,100	1,359	4,077	5,436	(1)	(5)	(5)	1,050	4,725	8,852	400	1,960	2,160	-	-	-	600	600	-	-
PS1F 2034 EPA 40%CC Limit	900	1,800	1,359	4,077	4,077	424	420	420	1,275	5,250	12,152	400	1,200	4,200	-	-	200	450	600	-	-
PS1F 2034 Low Battery Avail	-	1,500	1,359	4,077	6,796	(1)	(5)	(5)	1,050	4,725	8,852	400	1,760	1,920	-	200	200	600	600	-	-
PS1F 2034 NG Cap to 4 CC	-	1,800	1,359	4,077	5,436	(1)	420	420	1,050	4,725	8,327	400	1,540	1,740	-	-	-	450	600	-	-
PS1F 2034 SC CC	-	1,500	1,359	5,436	6,796	424	420	420	1,050	4,725	8,852	400	1,440	1,900	-	-	-	150	600	-	-
PS1F_2034_2035OSW	-	1,500	1,359	6,796	6,796	(1)	(5)	(5)	1,050	4,725	8,852	400	1,940	2,820	-	1,200	1,300	300	600	-	-
PS3F_2037_Force DEP CC, 2035 OffSW, EPA 40% CF	-	1,800	-	5,436	5,436	1,273	1,694	3,393	1,050	3,750	7,877	400	1,880	3,480	-	-	-	-	600	-	-
D P2 FB 2033	-	2,100	-	2,718	2,718	2,123	2,119	2,119	1,500	5,175	9,152	380	1,100	1,980	300	400	400	450	600	-	-
D P3 FB 2035	-	2,100	-	4,077	4,077	1,273	2,119	2,119	1,050	3,750	7,877	400	840	1,440	500	500	500	-	600	-	-

Duke Energy Progress Capacity

	SMR		Combined Cycle			Combustion Turbine			Total Solar			Battery paired with Solar			Battery Standalone			Onshore Wind		Offshore Wind	
Portfolio	2033	2038	2029	2033	2038	2029	2033	2038	2029	2033	2038	2029	2033	2038	2029	2033	2038	2033	2038	2033	2038
PS1F 2030 No CC High Grid Edge	-	-	-	-	-	-	-	-	5,100	12,000	13,760	3,240	5,520	5,520	1,500	4,000	4,000	1,650	1,650	1,100	1,100
PS1F 2032	-	-	-	-	-	-	425	425	2,250	7,575	12,635	1,120	4,580	4,580	1,700	2,700	2,700	1,650	1,650	3,300	4,400
PS1F 2034	-	300	-	-	-	850	850	850	1,650	6,975	9,260	640	1,920	2,760	200	300	1,300	1,200	1,650	3,300	4,400
PS1F 2035	-	-	-	1,359	1,359	850	850	850	1,650	6,975	11,060	640	1,300	3,420	200	200	2,000	1,350	1,650	-	2,200
PS1F 2034 Limit OffSW	-	-	-	-	-	850	850	850	1,650	6,975	12,410	640	4,100	5,220	200	2,500	3,500	1,650	1,650	1,100	2,200
PS1F 2034 No Tx Tfr Rate	-	-	-	-	-	850	850	850	1,950	7,275	10,535	800	2,800	4,040	300	300	1,300	1,200	1,650	3,300	4,400
PS1F 2034 No Tx Tfr Limit OffSW	-	-	-	1,359	1,359	850	850	850	1,950	7,275	12,710	800	3,220	4,100	300	1,700	2,700	1,650	1,650	1,100	2,200
PS1F 2034 Revised Low Load	-	300	1,359	1,359	1,359	425	425	425	1,650	6,975	9,335	640	2,660	3,500	300	300	1,300	1,650	1,650	-	1,100
PS1F 2034 Limit OnSW	-	-	-	-	1,359	850	850	850	1,650	6,975	9,260	640	2,720	3,560	200	200	1,200	1,200	1,650	3,300	4,400
PS1F 2034 Accel SMR	-	600	-	1,359	1,359	850	850	850	1,650	6,975	12,410	640	2,080	5,480	200	200	1,900	1,650	1,650	-	-
PS1F 2034 Force 2029 DEP CC	-	-	1,359	1,359	1,359	-	-	-	1,650	6,975	10,310	640	2,560	3,400	-	300	1,400	1,350	1,650	3,300	4,400
PS1F 2034 Shared Capacity	-	-	-	-	-	850	850	850	1,950	7,275	10,610	800	2,720	3,760	300	300	1,300	1,200	1,650	3,300	4,400
PS1F 2034 High Gas Cost	-	-	-	-	-	1,274	1,274	1,274	1,650	6,825	10,160	640	2,700	3,540	-	100	1,600	1,650	1,650	3,300	4,400
PS1F 2034 NoEIR	-	-	-	-	1,359	1,274	1,274	1,274	1,650	6,975	9,110	640	2,080	2,920	100	100	1,100	1,200	1,650	3,300	4,400
PS1F 2034 EPA 40%CC Limit	300	900	-	-	1,359	1,274	1,274	1,274	1,650	7,275	11,360	640	2,240	3,860	100	1,400	2,100	1,650	1,650	-	-
PS1F 2034 Low Battery Avail	-	300	-	-	-	1,274	1,274	1,274	1,650	6,975	10,310	640	2,120	3,420	100	100	1,100	1,200	1,650	4,400	4,400
PS1F 2034 NG Cap to 4 CC	-	-	-	-	-	850	850	850	1,650	6,975	10,310	640	2,980	3,820	200	600	1,600	1,350	1,650	4,400	4,400
PS1F 2034 SC CC	-	300	-	-	1,359	1,274	1,274	1,274	1,650	6,975	10,460	640	2,760	3,760	100	600	1,600	1,650	1,650	-	1,100
PS1F_2034_2035OSW	-	-	-	1,359	1,359	850	850	850	1,650	6,975	12,410	640	3,620	5,300	200	2,400	4,300	1,650	1,650	-	2,200
PS3F_2037_Force DEP CC, 2035 OffSW, EPA 40% CF	-	300	1,359	2,718	2,718	-	-	-	1,650	5,475	10,910	640	2,660	4,900	-	1,000	2,700	1,200	1,650	-	1,100
D P2 FB 2033	-	-	1,359	2,718	2,718	-	-	-	2,250	7,650	11,360	740	2,640	3,620	100	1,900	2,400	1,650	1,650	2,400	2,400
D P3 FB 2035	-	-	1,359	2,718	2,718	-	-	-	1,650	5,250	10,160	640	940	3,080	300	300	1,300	1,200	1,650	800	2,400

CERTIFICATE OF SERVICE

I certify that I have served a copy of the foregoing on all parties of record or to the attorney of record of such party in accordance with Commission Rule R1-39, by United States mail, postage prepaid, first class; by hand delivery; or by means of facsimile or electronic delivery upon agreement of the receiving party.

This the 28th day of May, 2024.

Electronically submitted
/s/Nadia L. Luhr