Comments of the Public Staff

Duke Energy Progress, LLC and Duke Energy Carolinas, LLC
2022 Carbon Plan

Docket No. E-100, Sub 179

July 15, 2022

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Executive Summary

North Carolina General Statute § 62-110.9

On October 13, 2021, North Carolina Governor Roy Cooper signed Session Law 2021-165 (formerly known as House Bill 951) into law, which has now been codified as N.C. Gen. Stat. § 62-110.9 (Section 110.9). Section 110.9 requires the North Carolina Utilities Commission (the Commission) to "take all reasonable steps" to ensure that statewide carbon dioxide (CO_2 or carbon) emissions from electric generating facilities are reduced by 70% from 2005 levels by 2030, and to achieve carbon neutrality[1] by 2050. Section 110.9 directs the Commission, by December 31, 2022, to develop a Carbon Plan that represents the least cost path for compliance with the emission reduction goals.[2]

Section 110.9 only applies to two electric public utilities in North Carolina—Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP) (together, Duke or the Companies)—and requires that the Commission consider input from Duke and other stakeholders in the process of developing its Carbon Plan. Section 110.9 allows for additional time to meet the interim 70% target, subject to certain conditions. Finally, Section 110.9 requires that the Carbon Plan

[1] N.C.G.S. § 62-110.9(a) defines "carbon neutrality" as follows: "for every ton of CO_2 emitted in the State from electric generating facilities owned or operated by or on behalf of electric public utilities, an equivalent amount of CO_2 is reduced, removed, prevented, or offset, provided that the offsets are verifiable and do not exceed five percent (5%) of the authorized reduction goal."

[2] A list of abbreviations used in these comments is attached as Public Staff Appendix A.

ultimately adopted by the Commission be reviewed every two years and allows for adjustments "as necessary."

Duke's Proposed Carbon Plan

On November 19, 2021, the Commission issued its Order Requiring Filing of Carbon Plan and Establishing Procedural Deadlines (Scheduling Order), in which the Commission determined that future Carbon Plan proceedings would be aligned with the traditional comprehensive Integrated Resource Plan (IRP) process carried out pursuant to Commission Rule R8-60. In addition, the Commission delayed Duke's next comprehensive IRP filings to September 2023.

In its filing on May 16, 2022, Duke submitted a verified Petition for Approval of Carbon Plan (Petition), which requests, in part, that the Commission hold the next comprehensive IRP in abeyance until September 2024 in order to synchronize the Carbon Plan and IRP proceedings and that the Commission adopt the Carbon Plan proposed by Duke (Proposed Carbon Plan). The Proposed Carbon Plan is similar in scope and depth to Duke's traditional comprehensive IRP filings.

In its Proposed Carbon Plan, Duke also requests that the Commission take specific actions, such as conclude that the Proposed Carbon Plan is reasonable for planning purposes, approve several near-term supply-side development and procurement activities, and acknowledge that Section 110.9 established new public policy goals that will inform the Companies' transmission planning process. These requests are addressed in the Requests for Relief Section.

Duke's Proposed Carbon Plan lays out two pathways and four unique portfolios for compliance with Section 110.9's interim carbon reduction goal and 2050 carbon neutrality goal. The two pathways deviate on the timing of the interim compliance goal, with the first pathway (Portfolio 1, or P1) achieving a 70% reduction by 2030 and the second pathway (Portfolios 2, 3, and 4, or P2, P3, and P4, respectively) delaying interim compliance by two to four years, as permitted by Section 110.9.[3] Citing the uncertainty surrounding the availability of certain non-emitting resources such as offshore wind and nuclear small modular reactors (SMRs), the four portfolios envision different technology additions along with interim compliance years. The Proposed Carbon Plan proposes portfolios that achieve interim compliance by: 2030 with offshore wind (P1); 2032 with offshore wind (P2); 2034 with SMRs (P3); and 2034 with offshore wind and SMRs (P4). Notably, all portfolios rely upon an expansion of DEC's Bad Creek pumped storage hydro-electric station in 2032.

[3] N.C.G.S. § 62-110.9(4) states, in relevant part, that "the Commission shall not exceed the dates specified to achieve the authorized carbon reduction goals by more than two years, except in the event the Commission authorizes construction of a nuclear facility or wind energy facility that would require additional time for completion due to technical, legal, logistical, or other factors beyond the control of the electric public utility, or in the event necessary to maintain the adequacy and reliability of the existing grid."

The Proposed Carbon Plan touches on all aspects of utility planning, including generation, transmission, and distribution systems. Significant quantities of solar, battery storage, onshore wind, SMRs, advanced nuclear reactors, and natural gas plants capable of burning hydrogen are added in all portfolios. Each portfolio includes substantial investments in expanding the transmission system to accommodate new generation and to reliably retire existing coal generation.

Duke also provided an alternative set of portfolios that are based on the assumption that firm natural gas supply from the lower-cost Dominion South (DS) hub trading point does not materialize and that gas supply from the Transco line is limited.[4] Access to this gas supply would rely upon Appalachian gas delivered to North Carolina by natural gas pipelines that have not yet been completed—specifically, Mountain Valley Pipeline, LLC (MVP) and MVP Southgate. Given the uncertainty around this major issue and the Public Staff's concern about access to DS gas, the Public Staff has also reviewed the alternative portfolios.

The Proposed Carbon Plan further provides the expected cost of each portfolio in terms of its Present Value of Revenue Requirement (PVRR) and its retail bill impact. These costs as presented in the Proposed Carbon Plan do not

[4] Duke's potential access to firm Appalachian gas has been a contested issue in prior IRP and avoided cost proceedings. The Public Staff first identified this as an issue in the 2020 Avoided Cost proceeding (*see* Initial Comments of the Public Staff, filed on January 25, 2021, in Docket No. E-100, Sub 167, at 44-46), and again in the 2020 IRP proceeding (*see* Initial Comments of the Public Staff, filed on February 26, 2021, in Docket No. E-100, Sub 165, at 92).

paint a full picture of the total costs to ratepayers. For instance, many costs that are common to all portfolios, such as the Red Zone Transmission Expansion Plan (RZTEP), ongoing spending on the Grid Improvement Plan, and storm securitization costs, are not included in the PVRR or bill impact analysis, which leads to understated costs. While the Public Staff understands that the costs are presented to compare the relative impact of each portfolio, including all costs would paint a clearer picture of the financial burden imposed on ratepayers over time. All Proposed Carbon Plan portfolios project significant increases in customer bills through 2035, as the resulting increases in rate base and increasing natural gas prices more than outweigh any fuel cost savings from incorporating high levels of renewable energy.

In support of the Proposed Carbon Plan portfolios, Duke includes an execution plan that differentiates between near-term actions, intermediate-term actions, and long-term planning in support of Section 110.9's carbon reduction goals. Duke is seeking approval of certain activities related to its existing and planned supply-side resources that are consistent with the pace of deployment across all portfolios, while monitoring certain execution risks and adjusting the Carbon Plan in the future as uncertainties are resolved. Generally, the Public Staff agrees with this approach as discussed more fully below, particularly given the substantial uncertainty around key assumptions such as future natural gas pricing and supply, development timing and the capital and operational costs of technologies not deployed at scale in North Carolina (e.g., offshore wind and SMRs), future load growth and the impact of electrifying the transportation and industrial sectors, and the costs of integrating and producing hydrogen as a replacement for natural gas.

Taken as a whole, the Proposed Carbon Plan represents an earnest effort by Duke to meet the carbon reduction goals mandated by Section 110.9, with an ambitious set of near-term actions and multiple pathways to achieve compliance. After a thorough review of the Proposed Carbon Plan and Duke's discovery responses, the Public Staff has three overarching concerns with regard to the Companies' modeling assumptions: (1) the Companies may have overstated the magnitude of the need for natural gas generation by utilizing aggressive assumptions about hydrogen and natural gas availability and prices; (2) the Companies may have undervalued some renewables through rigid solar and storage modeling and inflexible third-party assets; and (3) the Companies may have understated the actual costs ratepayers will bear to implement the transition to carbon neutrality. In light of these concerns, the Public Staff recommends modifications—both immediate and in the longer term—as presented in more detail throughout these comments.

The Public Staff views this initial, truncated review period to serve as an opportunity for stakeholders to review the inputs, assumptions, and conclusions, and to make recommendations to the Commission to improve the accuracy and execution of the Proposed Carbon Plan that is ultimately adopted by the Commission. The Public Staff's analysis will undoubtedly continue to evolve as these proceedings progress, and the Public Staff will utilize its evolving analysis to provide input in the biennial reviews and adjustments of the Carbon Plan.

Summary of the Public Staff's Investigation and Recommendations

The Public Staff has reviewed the Companies' Proposed Carbon Plan and investigated many of the driving assumptions and inputs to the models used to determine a path to compliance with the emission reduction targets in Section 110.9 and ascertain the least cost portfolio. The Proposed Carbon Plan modeling relies on thousands of factors which shape each portfolio. While the Public Staff may not agree with each of Duke's model inputs, the Public Staff has focused on those factors that are likely to be material to the Carbon Plan outcomes with respect to both the interim 70% CO_2 reduction target and the 2050 carbon neutrality target.

The Public Staff presents its findings and recommendations in two sections: (1) the first section addressing the requests within Duke's Petition, including the short- to medium-term actions meant to ensure achievement of the 70% CO_2 reduction target; and (2) the second section addressing the requests related to the achievement of the 2050 carbon neutrality target, which may not need resolution until future Carbon Plan updates.

The Public Staff is committed to achieving the CO_2 reduction goals set forth in Section 110.9 through the Carbon Plan process. The interim goal of a 70% reduction from 2005 levels by 2030 represents the most immediate challenge, and the Commission must make decisions based upon both Duke's Proposed Carbon Plan and input from intervenors. The Commission will also be required to make future adjustments to the Carbon Plan to reach the 70% target. Due to the significant amount of uncertainty regarding the assumptions made in each portfolio, a deterministic evaluation of portfolio costs and bill impacts does not provide sufficient information for the Public Staff to select or endorse a particular portfolio. As shown in the sensitivity analysis in Proposed Carbon Plan Figure 3-11, the total cost of each portfolio could be significantly influenced by changes in the capital cost of new generation. For example, P1's PVRR could increase by as much as $8 billion, or approximately eight percent, if the capital cost curve for solar capacity does not decline as forecasted. This variable is only one of thousands that could impact the final PVRR and bill impact analysis.

Proposed Carbon Plan Tables 3-2 and 3-3 summarize Duke's metrics upon which it evaluated each portfolio, relative to several objectives such as cost and affordability, CO_2 emissions impact, reliability and flexibility, and executability.

Execution risks will likely pose the most significant challenge to achieving the CO_2 reduction goals in Section 110.9, and should, therefore, be given substantial attention by the Commission. Simply selecting the least cost portfolio based on PVRR, without considering other factors, would put ratepayers at significant risk of higher than projected costs if the lower costs do not materialize.

<u>Execution Risk</u>

Executability is a major factor in each portfolio. For example, the Commission must determine the earliest potential date for operation of offshore wind or SMRs, or the upper limit for annual interconnections of new solar and storage resources given existing transmission constraints. Currently, these values are not certain. Therefore, the Public Staff has attempted to ascertain which portfolios are most dependent on the most aggressive assumptions and thus are at the highest risk of failing to achieve their stated goals at their estimated costs.

Table 1 below summarizes several key risk factors that exist across all four portfolios. The Public Staff selected these risk factors based on its review of the major differences between each portfolio, but the list is not exhaustive. For example, the 2032 expansion of DEC's Bad Creek pumped storage hydro station is not identified in this list; it is not economically selected, but rather "forced" into each portfolio despite significant uncertainty if the project cost estimates are reasonably accurate or the project can even be completed.

Table 1: Key Risk Factors Across Portfolios

Portfolio	Average Pace of Interconnections, MW, 2026-2030, for:		First Year for:		Total Natural Gas by 2035		% of DEC Load Served by DEP, 2035
	Solar	Batteries[5]	OSW	SMR	MW	% of Total Generation	
P1	High (~1,420)	High (~488)	2029	2032	3,559	21%	10.6%
P2	Moderate (~984)	Moderate (~284)	2029	2033	3,559	24%	13.0%
P3	Moderate (~1,014)	Moderate (~252)	None	2032	3,934	26%	10.8%
P4	Moderate (~925)	Low (~166)	2031	2032	3,559	26%	10.4%

Relying on very high, unprecedented levels of annual solar interconnections—and any necessary interconnection facilities and transmission upgrades—could jeopardize interim compliance. P1 adds an average of over 1,400 MW of solar each year from 2026 through 2030. Duke would have to accelerate interconnection processes and transmission upgrades significantly to accommodate this schedule, which would cause cost increases that are not reflected in the PVRR estimates or bill impacts.

Offshore wind (reflected in tables throughout as OSW) is added in all portfolios but P3, with P1 and P2 adding their first 800 MW block in 2029 and P4 delaying the addition of offshore wind until 2031. P2 adds a second 800 MW block in 2031, which is a rapid deployment of a technology with which utilities have

[5] Including batteries co-located with solar.

limited experience in the United States. While it is possible that offshore wind could be in service by 2029, significant delays could be caused by regulatory challenges, supply chain issues, and large transmission upgrades. Duke acknowledges that bringing offshore wind online by 2030 would require partnering with a project that has advanced beyond the leasing stage; the nearest such project would be the Kitty Hawk lease area.[6]

Similarly, SMRs are a novel technology not currently commercially available. All portfolios rely on SMR capacity first being deployed in 2032 or 2033, with one additional reactor added in each year from 2034 through 2036. If the Nuclear Regulatory Commission (NRC) delays granting licenses to SMR generators, construction of the modular reactors is delayed, or fuel supply constraints arise, reaching interim compliance while relying on SMRs could prove difficult. P4 has the latest offshore wind dates, while P2 adds an additional year to install its first SMR. The large-scale deployment of offshore wind in P2, with 1,600 MW by 2031, represents a significant development risk.

Each portfolio has a significant expansion of Duke's natural gas fleet. Today, natural gas makes up slightly over 30% of total energy generation by Duke. The continued operation and new construction of natural gas generation despite the carbon reduction goals in Section 110.9 is enabled by an increasing reliance

[6] *See* Proposed Carbon Plan Appendix J at 6.

on hydrogen to supplant natural gas. As discussed in Proposed Carbon Plan Appendix O, Duke assumes that: (1) the blend of green hydrogen[7] will increase from three percent in 2035 to 15% in the early 2040s; (2) new peaking plants built in 2040 and beyond can run entirely on hydrogen; and (3) new Combined Cycles (CCs) are converted to 100% hydrogen in the late 2040s. These assumptions are based on achieving United States Department of Energy target electrolysis efficiencies and having sufficient excess renewable energy to produce the necessary quantities of hydrogen. Thus, new natural gas capacity represents a portfolio risk because if the production and blending of hydrogen does not materialize, meeting the carbon reduction goals will require substantial new generation to replace natural gas plants that would become stranded assets for which ratepayers would be responsible.

Rate Disparity

Duke's PVRR for each portfolio and the bill impact analyses are almost certainly understated, and the growing rate disparity between the rates of DEC and DEP customers is likely also understated. The PVRR and bill impact analyses provided do not reflect certain costs, such as the RZTEP upgrades identified in Proposed Carbon Plan Appendix P. The Public Staff has spoken extensively in

[7] Green hydrogen refers to hydrogen produced via electrolysis using 100% renewable energy. All references to hydrogen in these comments refer to green hydrogen, unless otherwise stated.

stakeholder meetings about the rate disparity between DEC and DEP. This disparity and factors that may exacerbate it in the future are discussed in more detail later in these comments. Approximately six percent of DEC's annual energy demand is served by generation resources located in DEP territory in all four portfolios in model year 2022. By 2035, the percentage grows substantially in each portfolio, with P2 having the highest level of transfers.

This percentage represents a proxy that indicates how generation and transmission assets built in DEP's territory and recovered via base rates from DEP customers could increasingly serve DEC's customers. While amending the Joint Dispatch Agreement (JDA) between DEC and DEP could reallocate the costs of this arrangement between the two utilities, the Public Staff is concerned that amending the JDA would be insufficient to equitably allocate shared Carbon Plan costs between DEC and DEP. The goal of more closely aligning the rates of DEC and DEP is not a specific objective of Section 110.9; however, the Commission should take steps in its Carbon Plan to prevent worsening of an already significant disparity. The costs of complying with the Carbon Plan should be allocated in proportion to the degree by which each utility relies upon those investments to meet its Section 110.9 compliance. The continued planning of two systems through one carbon reduction plan presents significant inefficiencies and challenges, both from a technical and financial perspective. Duke should promptly evaluate the steps necessary to consolidate the DEC and DEP utilities into a single operating entity and present the Commission with a timeline for implementation. Consolidating the utilities will reduce inequitable cost allocation among customer groups, maximize planning efficiencies, and reduce administrative burdens by eliminating duplicate processes and proceedings. The Public Staff recognizes that consolidation involves many moving parts but believes consolidation is the most prudent means for addressing current and potentially increasing rate disparity.

Portfolio Costs

The Public Staff reviewed costs and bill impacts for each portfolio, as shown in Table 2 below. While the Public Staff is concerned with whether each portfolio represents a reasonable and realistic plan for CO_2 emission reductions while maintaining system reliability, costs are also critical to meeting the least cost mandate in Section 110.9. While P3 appears to be the least cost portfolio, the difference between P3 and P4 PVRR is nearly negligible. As shown in Proposed Carbon Plan Table 3-3, all portfolios predict a widening of the rate disparity between DEC and DEP, with P1 and P2 increasing this disparity substantially, demonstrating these portfolios' heavy reliance on generation and transmission expansion in DEP's territory needed to serve DEC's load and Duke's overall carbon reduction goals. As discussed later in these comments, the PVRR and bill impact analysis exclude significant costs that are considered common across all portfolios, and therefore, do not provide a complete picture of expected bill increases for retail customers.

Table 2: Cost Impacts of Each Portfolio

Portfolio – 70% Year	PVRR 2035 ($M)	% Over Least Cost (LC)	PVRR 2050 ($M)	% Over LC	Monthly Bill Impact (2030)	
					DEC	DEP
P1 – 2030	47,276	7.6%	101,106	6.2%	$8	$35
P2 – 2032	45,543	3.6%	98,767	3.7%	$5	$29
P3 – 2032	43,944	LC	95,202	LC	$7	$19
P4 – 2034	44,071	0.3%	95,503	0.3%	$5	$18

Portfolio Preference

The Proposed Carbon Plan has many ambitious assumptions, only some of which are addressed here. The Public Staff believes P1 has the most significant development risk because it relies heavily on interconnecting unprecedented levels of solar and batteries to meet the interim compliance goal, while simultaneously adding significant quantities of both offshore wind and SMRs. Given the lengthy construction schedules estimated for transmission system upgrades identified in Duke's recent Transition Cluster Study (TCS),[8] the Public Staff is not persuaded that such a buildout of solar resources is possible at this time. P2 may be unrealistic given the schedule for offshore wind development, even if it allows one additional year to bring the first SMR online. P3 has no offshore wind planned, ignoring significant resource potential in the Kitty Hawk and Carolina

[8] Some of the upgrades identified in the TCS Phase 1 Report are also identified as necessary to alleviate congestion in the "red zone" in Proposed Carbon Plan Appendix P. Several of these upgrades, such as all reconductoring projects on the Cape Fear – West End 230 kV line, are estimated to require five and a half years to complete. *See* TCS Phase 1 Report at 24, accessible at https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/2022-02-28_DEP_TC_Phase_1_Study_Report.pdf (accessed June 30, 2022).

Long Bay lease areas, and instead relies on natural gas, solar, batteries, and SMR deployment to meet the interim goal in 2032. P4 relies upon a balance of resources and a slightly less aggressive interconnection schedule and may represent the most achievable portfolio, particularly given recent supply chain issues and inflationary pressures affecting the entire economy.

Given the development risks and the costs of each portfolio, the Public Staff believes that P4 currently represents the most feasible portfolio in the Proposed Carbon Plan. However, at this time the Public Staff is not selecting or endorsing any particular portfolio, as too much remains unknown, and the iterative Carbon Plan updates should provide a process by which the short-term execution plan can be adjusted to align with long-term goals and developments. The Commission should not lock onto any one portfolio at this time. However, a diverse mix of resources, without overreliance on any single resource type, will provide Duke's ratepayers with the most robust and least cost path to compliance. As more confidence is gained in development timelines for new resources in this proceeding and future Carbon Plan updates, the Public Staff may be in a better position to endorse a more aggressive portfolio. At this time, however, P1 (and to a lesser extent P2) appears to put ratepayers at the most undue risk of significant rate impacts.

The Public Staff's Recommendations[9]

The Public Staff recommends that the Commission direct Duke to develop a new portfolio (Portfolio 5 or P5) that should include the refinements itemized in the list below. The Public Staff requests that Duke complete the P5 model run and determine if the short-term execution plan detailed in its Petition, particularly item 3(a), still aligns with the results from P5. Duke should provide the model results in a supplemental filing no later than August 19, 2022. To the extent that actions identified in the short-term execution plan are validated by the P5 model run, the Public Staff recommends approval of those actions within the near-term execution plan. The Public Staff acknowledges that Duke has performed a substantial amount of modeling for the Proposed Carbon Plan, including transitioning to an entirely new set of models, in a condensed time period relative to past IRPs. To the extent that Duke believes a P5 recommendation may be difficult or impossible to implement during this proceeding, Duke should address this in its reply comments or direct testimony, as applicable, and propose an alternative solution. However, the intent of the P5 model run is to validate the short-term execution

[9] The Public Staff's recommendations as set forth in these comments are summarized in Public Staff Appendix B.

plan, and the Public Staff believes Duke should begin implementing the recommendations as soon as possible to facilitate a timely supplemental filing.[10]

Recommended Portfolio 5 Model Run

The Public Staff recommends that Duke incorporate the changes listed below into a new P5 model run, as well as in all future Carbon Plan filings.

1. Set an interim compliance year of 2032, with solar interconnections limited as in P4, and allow the economic selection of both SMR and offshore wind resources.
2. Model the Belews Creek generation facility at 50% capacity on natural gas beyond 2036. Belews Creek has the capability to run both units up to 50% on natural gas, yet Duke plans to retire this plant entirely at the end of 2035. Keeping this plant online could potentially defer the selection of advanced reactors in every DEC portfolio in 2037. *See* Modeling Results and Evaluation section.
3. Make corrections to solar plus storage (S+S) modeling. Duke's current modeling of S+S resources does not include a battery component that can be dispatched by Encompass, its primary model. Rather, Duke predetermined the output profile, based on outside modeling using hourly

[10] At this time, the Public Staff is unable to perform its own P5 model runs due to the difficulty in validating Duke's output data and the complexity of the external modeling processes performed for each portfolio. These issues are discussed in more detail later in these comments.

avoided cost prices that are not related to, or derived from, EnCompass. Duke should correct the method by which it models S+S resources to allow EnCompass to select and optimally dispatch the energy storage component. The Public Staff's modeling suggests that Duke's modeling of S+S may be leading to material changes in resource selection. *See* Modeling Results and Evaluation section.

4. Remove limits on the total amount of 4-hour and 6-hour battery capacity that can be added. These limits were implemented in recognition of the declining capacity value of storage resources, but the EnCompass model already includes declining capacity value constraints for solar, battery storage, and wind resources. *See* Modeling Results and Evaluation section.
5. Remove dependence on hydrogen to run natural gas plants. *See* Commodities section.
6. For new selectable solar, model 45% of the total capacity as a Power Purchase Agreement (PPA), rather than a rate-based utility asset. This would reflect the split mandated by Section 110.9. PPA solar should be allowed to be dispatched down based on economics and should not be modeled as must-take. *See* Modeling Results and Evaluation section.
7. Utilize the Low Case assumption for Energy Efficiency (EE). *See* Grid Edge Programs section.
8. Remove access to Appalachian natural gas. *See* Commodities section.

9. Use a simple average of Transco Zone 4 and Zone 5 pricing for existing and future CC natural gas-fired plants and Zone 5 pricing for combustion turbines (CTs). *See* Commodities section.
10. Set fuel oil to a minimum blend of 20% in January for CTs and a minimum blend of zero percent in January for CCs. *See* Commodities section.
11. Allow the model to select both J-Class and F-Class CCs and CTs and utilize retirement dates for existing CTs that match the most recent depreciation studies. *See* Modeling Results and Evaluation section.
12. Implement a transmission tariff for the DEP to DEC intertie in EnCompass to match, at a minimum, the current Federal Energy Regulatory Commission's (FERC) approved utility specific non-Firm Service annual $/kWh tariff as found in the publicly available Open Access Transmission Tariff (OATT) for each utility. *See* Transmission System section.
13. Utilize an optimization period spanning the entire planning horizon for at least one model run. This should validate whether natural gas CCs are still selected if future hydrogen conversion costs are known. *See* Portfolio Costs and Risks section.

Additional Recommendations

In addition to the P5 model run described above, the Public Staff recommends that the Commission:

14. Grant Duke's request to delay its next comprehensive IRP to 2024. Duke should be required to file updated IRPs, pursuant to Commission Rule R8-60(j), in 2023. This report should update the Commission and stakeholders on milestones and development activities pursuant to the Commission's 2022 Carbon Plan.
15. Order Duke to proceed with the activities related to developing offshore wind and SMR capabilities outlined in its Petition and provide substantive updates on progress toward offshore wind and SMR development in its 2023 IRP update and again in its Carbon Plan filing in 2024. Duke should also provide a general timeline of the Bad Creek II project along with expected project spend on a quarterly basis from 2023 to the project in-service date. *See* Request for Relief section and Portfolio Costs and Risks section.
16. Direct Duke, in future Carbon Plan proposals, to include other costs such as those related to the RZTEP in the PVRR and bill impact analysis, even if those costs are presumed to be common across all portfolios. *See* Portfolio Costs and Risks section.
17. Require Duke to provide an update in its 2024 Carbon Plan update regarding any changes to the modeling of the replacement of battery storage resources at the end of their operable lives in order to address Public Staff concerns regarding the continual replacement of capacity that

has reached the end of its operable life with identical resources. *See* Modeling Results and Evaluation section.

18. Direct Duke to update transmission cost adders for future Carbon Plans with the results of the most recent interconnection cluster study. *See* Transmission Upgrade section.
19. Direct Duke to expand its internal transmission planning horizon to 20 years. *See* Transmission Planning section.
20. Require Duke to continue to provide updated locational guidance maps in future Definitive Interconnection System Impact Study (DISIS) and procurement solicitations, and to show any proactive transmission upgrades expected to be in service in this locational guidance. *See* Transmission Planning section.
21. Direct Duke to clearly identify any proactive transmission upgrades and provide justification and the lead time to construct them in future Carbon Plans. *See* Transmission Planning section.
22. Require Duke to file supplemental testimony prior to the date of the evidentiary hearing explaining the findings of its proposed interconnection cluster study to allow proper consideration by the Commission in its preparation of its Carbon Plan. *See* Transmission Planning section.

23. Disallow the recovery of any costs of any proactive transmission projects identified in the Commission's plan in any form until each project is placed into service and is used and useful. *See* Transmission Planning section.
24. Direct Duke, in its next Carbon Plan proposal, to include fixed operations and maintenance (O&M) costs for existing units in its modeling. *See* Portfolio Costs and Risks section.
25. Direct Duke to pursue procurement of at least 1,000 MW of solar capacity in the 2022 Solar Request for Proposals (RFP), based on a minimum, "no-regrets" quantity of 3,381 MW of economically selected solar and S+S in the Proposed Carbon Plan, plus an anticipated Competitive Procurement of Renewable Energy (CPRE) shortfall of 591 MW. *See* 2022 Solar RFP Target Capacity section.
26. Direct Duke, in its 2024 Carbon Plan filing, to utilize the results of the 2022 Solar RFP to create solar resources in the EnCompass model that reflect actual bids received in DEC and DEP territories, and then allow the model to select solar optimally across the combined territories based on economic factors. *See* 2022 Solar RFP Target Capacity section.
27. Direct Duke, in its 2024 Carbon Plan update, to provide the model with the option to retire natural gas CCs and CTs in 2047 as an alternative to converting all plants to run on 100% hydrogen. *See* Portfolio Costs and Risks section.

28. Direct Duke to perform a transparent analysis in future Carbon Plans that clearly illustrates the impact on the load forecast of: (1) the enablers described in Proposed Carbon Plan Appendix G, (2) the effects of market transformation, and (3) any other changes that might be considered in the context of a future multi-year rate plan (MYRP).
29. Deny Duke's request for approval of its proposed plan to update the DSM/EE utility system benefits and value of those benefits and instead allow consideration of this plan during a review of the DSM/EE Mechanism in which all components of the Mechanism, including Portfolio Performance Incentive (PPI) and Performance Return Incentive (PRI) percentages, can be considered together.
30. If the Commission approves Duke's EE proposal, require that the issue of the treatment of "as-found" savings for EE cost recovery purposes be considered in a separate proceeding initiated for this purpose.
31. Defer a decision on Duke's request to move forward with its Grid Edge programs and require Duke to file for approval of the individual programs in separate dockets and request a review of the EE Mechanism for any changes that would impact cost effectiveness, savings, or costs.
32. Direct Duke, in its 2024 Carbon Plan update and general rate cases, to propose cost allocations that address the rate disparity between DEC and DEP and equitably allocate costs of new generation and transmission in a

manner that is proportionate to the benefits received by each utility's customers as an interim measure. In addition, Duke should promptly evaluate the steps necessary to consolidate the DEC and DEP utilities into a single operating entity and present the Commission with a timeline for implementation. *See* Portfolio Costs and Risks section.

Interim Compliance Year

Section 110.9 allows for a delay in the interim compliance target of 2030 by no more than two years, unless more time is necessary to enable offshore wind or SMRs, or to ensure the adequacy and reliability of the existing grid. While the Public Staff's starting point is to attain 70% CO_2 emissions reduction by 2030, the Public Staff recommends that the Commission consider several factors when determining the year in which Duke must comply with the interim compliance goal. The primary factor the Commission should consider is the risk of failure to achieve the interim 70% target in the event that key assumptions underlying the Carbon Plan prove to be incorrect. Achieving interim compliance will greatly depend upon whether the required new resources are able to interconnect in a safe and reliable manner in the timelines proscribed by each portfolio. The greater the level of annual solar and battery storage interconnections, and the earlier each plan relies upon onshore wind, offshore wind, and SMRs, the greater the overall risk. The level and pace of interconnections also will place significant strain on the transmission system, where upgrades often take years to complete. The Public Staff views execution risk as the greatest determinant of whether the Commission should grant a delay in achieving interim compliance. Execution risk is discussed in more detail in the Portfolio Costs and Risks section of these comments.

In addition, the Public Staff recommends that the Commission consider the relative costs of earlier compliance in P1. As shown in Figure 1, the CO_2 emissions associated with each portfolio follow similar trajectories toward zero emissions in 2050. In determining whether a delay in interim compliance might be justified, the Public Staff sought to understand the carbon reduction in each portfolio relative to the costs.

Figure 1: Annual CO2 Emissions in Each Portfolio

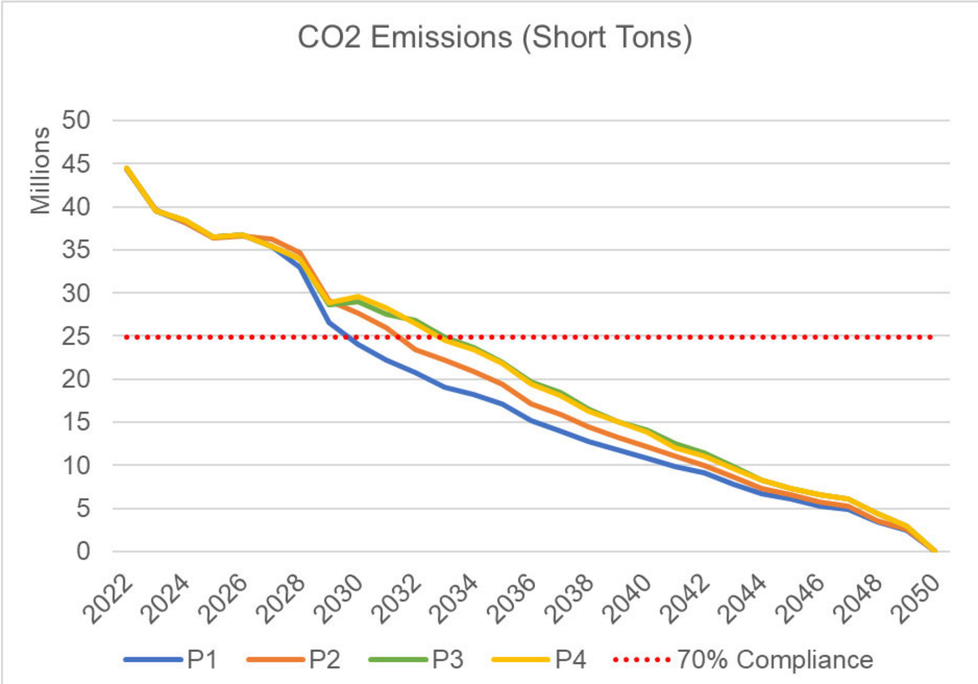


Table 3 below shows an analysis of each portfolio's combined system cumulative CO_2 emissions and total PVRR through 2035 and 2050. By dividing the reduction in PVRR relative to P1 by the increase in CO_2 emissions in other portfolios relative to P1, the cost of carbon abatement for P1 relative to the delayed portfolios can be estimated. While there is currently no state or federal direct cost of carbon assigned to the Companies, one useful metric in evaluating the reasonableness of this cost of carbon abatement is the Social Cost of Carbon (SCC), estimated by the Interagency Working Group on Social Cost of

Greenhouse Gases.[11] While this estimate is not binding on the Commission, Duke, or the Public Staff, it can serve as a useful reference point in evaluating whether a delay in interim compliance is warranted.[12]

[11] US Gov't, Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990, at 5 (February 2021).

[12] On January 7, 2022, Governor Cooper issued Executive Order 246, which encourages non-cabinet agencies such as the Commission to incorporate the SCC published by the Interagency Working Group into their decision-making processes.

Table 3: Summary of Carbon Abatement Costs Relative to P1

Portfolio	Cumulative CO_2 (M short tons)	Incremental CO_2, Relative to P1 (M short tons)	Total PVRR ($B)	PVRR Savings, Relative to P1 ($B)	Cost of Carbon Abatement ($/short ton)	US Gov SCC[13] ($/short ton)
Through 2035						
P1	412	-	$ 47.3	-	-	$ 61
P2	435	23	$ 45.5	$ (1.7)	$ 76	
P3	448	36	$ 43.9	$ (3.3)	$ 93	
P4	448	36	$ 44.1	$ (3.2)	$ 89	
Through 2050						
P1	532	-	$ 101.1	-	-	$ 61
P2	568	36	$ 98.8	$ (2.3)	$ 65	
P3	601	69	$ 95.2	$ (5.9)	$ 86	
P4	599	67	$ 95.5	$ (5.6)	$ 84	

This table illustrates the cost of carbon abatement by showing the cost per short ton to meet the interim compliance goals in 2035 and 2050 by implementing P1, relative to other portfolios. For example, if interim compliance is delayed from 2030 (P1) to 2032 (P2), P2 emits an incremental 36 million short tons of CO_2 through 2050 while saving ratepayers $2.3 billion in present value costs. Relative to P2's delayed compliance, P1 could achieve interim compliance in 2030 at an average cost of $65 per short ton. Compared to the $61 per short ton SCC, this outcome suggests that the incremental cost to ratepayers to achieve earlier compliance is not justified by the estimated SCC. This analysis is supported by

[13] At a three percent discount rate and an emission year of 2035, the report cites $67 per metric ton, or $61 per short ton.

Duke's federal CO_2 tax production cost sensitivity analysis, which found that the "earlier incremental cost to enable CO_2 emission reductions is not fully offset by applying the Social Cost of CO_2 through 2050."[14]

System reliability is also an important factor. In its Proposed Carbon Plan, Duke identifies two key metrics for reliability and flexibility: 95th percentile expected net load ramp in MW/hour, and average CC starts per unit per year. The Public Staff agrees that these are reasonable metrics. A more extreme net load ramp requires resources either to rapidly respond to changing net load or risk having to shed load. CCs are designed to run as a baseload source and increasing the number of unit stops and starts will lead to higher O&M costs and potentially increase the risk for unit failures. By 2035, P1 clearly requires the most system flexibility, with an expected net load ramp of 10,803 MW/hour and an estimated 99 CC starts per unit per year. Of the delayed portfolios, by 2035, P4 has the lowest expected net load ramp of 7,922 MW/hour and the fewest expected CC starts at 67.[15]

Portfolios and Public Staff Evaluation

This section presents the Public Staff's detailed analysis, comments, and recommendations on the technical aspects of the portfolios presented in the

[14] *See* Proposed Carbon Plan Appendix E at 95-96.

[15] *See* Proposed Carbon Plan Chapter 3, Table 3-3 at 20.

Proposed Carbon Plan and provides the analytical support underlying many of the Public Staff's proposed recommendations. These recommendations are based on the Public Staff's review of the Proposed Carbon Plan, Duke's responses to discovery requests, and independent EnCompass model runs.

Modeling

In energy planning, modeling is the process of formulating and evaluating proposed plans, typically using computer software. In early 2022, the Public Staff confirmed that Duke would be utilizing the EnCompass energy modeling software developed by Anchor Power Solutions (APS) in preparing its Proposed Carbon Plan. Per APS, EnCompass has served as the basis for regulatory filings in 17 states. Thereafter, the Public Staff also obtained a license to use EnCompass. This was the first time either the Public Staff or Duke had used EnCompass in connection with an IRP proceeding. EnCompass provides the Public Staff with the ability to run both capacity expansion models and production cost models.[16]

Capacity expansion models are those that look out over the planning horizon (2022 through 2050) and make decisions regarding what generation resources to build and retire and how to dispatch units. With its generator resource

[16] EnCompass has the ability to run successive energy models. For example, a capacity expansion plan can select new generation resources for optimization and those resources can directly feed into a production cost model for a more detailed dispatch optimization.

decisions, a capacity expansion model will normally utilize typical on-peak and off-peak load days divided into several multi-hour blocks of time. Thus, a capacity expansion model solves for fewer than 8,760 hours per year, which reduces computational complexity and run times while optimizing the selection of new generators and the dispatch of all generators. However, due to the lower hourly granularity of the capacity expansion model, it cannot fully capture dispatch behavior around peak and minimum loads.[17]

Production cost models are those that look out over the entire planning horizon, or a shorter time period, and make decisions on how to dispatch a portfolio of generation resources over all 8,760 hours per year. New and retired resources determined in the capacity expansion model will flow into the production cost model. Without the need to make resource selection and retirement decisions, the production cost model is free to optimize not only over representative days and hours, but over every hour in the year. This optimization yields more accurate generator dispatch, production costs, and emissions data, because the model more closely resembles the actual demand faced by system operators.

To develop its recommendations, the Public Staff ran multiple capacity expansion models and production cost models of Duke's portfolios, first to validate

[17] *See* Proposed Carbon Plan Figure E-10 for a visual example.

Duke's outputs and later to test the impact of various assumptions in the Proposed Carbon Plan.

With support from APS, the Public Staff loaded Duke's EnCompass input files into its own databases and attempted to re-run the capacity expansion and production cost models to validate that they produced the same output values Duke obtained. However, the Public Staff was unable to directly validate the output from Duke's models. While some slight differences might be expected due to variance in generator outage timing, particularly in generator dispatch, results should align closely. The Public Staff's initial attempts to run the capacity expansion models failed, and differences in dispatch decisions, emissions, and system costs were found in the production cost models. Other intervenors encountered this problem as well, which Duke fixed on May 25, 2022.[18] Two weeks later, on June 8, 2022, Duke published a document to its Datasite identifying the aforementioned issue as well as an additional issue with capacity expansion plans (*see* Public Staff Exhibit 1).

After resolving both issues, the Public Staff re-ran the models and produced results that were closer to Duke's, but still not exactly the same. However, much of the deviation occurred in later years, 2040 and beyond, and the Public Staff was

[18] *See* the July 8, 2022 letter filed in this docket by the Southern Alliance for Clean Energy (SACE), the Sierra Club, the Natural Resources Defense Council, and the North Carolina Sustainable Energy Association (NCSEA), detailing issues with validating Duke's datasets and model runs.

therefore comfortable using EnCompass as a tool to determine the relative impact of some of Duke's assumptions. As described in Chapter 2 and Proposed Carbon Plan Appendix E, Duke utilized a series of modeling steps to arrive at the final capacity expansion plan. These steps are summarized in Table 5 below. Some of these steps, such as estimating system reliability using the Strategic Energy and Risk Valuation Model (SERVM), require external modeling or analysis that is performed outside of the EnCompass model. Given the complex nature of these additional steps, the novelty of the EnCompass software to the Public Staff, the delay caused by the capacity expansion model error and production model issues, and the compressed time period for these detailed and complex proceedings, the Public Staff is not submitting its own carbon plan in this proceeding. Instead, the Public Staff used EnCompass as a tool in its investigation. By varying inputs and assumptions in the linked capacity expansion and production cost models in steps 3 and 4, and in the final production cost model in step 8, the Public Staff was able to determine the general impact of the inputs and assumptions used in the Proposed Carbon Plan and enhance its understanding of their materiality.

Table 4: Summary of Carbon Plan Modeling Steps

Step	Step Description	Requires External Model or Analysis?
1	Base Capacity Expansion (CapEx) Run with Fixed Coal Retirement Dates.	No
2	Re-run of CapEx model with coal units retired economically; an estimated capital and O&M cost schedule for running coal units is derived from Step 1's model outputs.	Yes
3	Final CapEx model, with the coal retirement dates from Step 2 fixed.	No
4	Production Cost (PC) model, using the resource selections from Step 4.	No
5	Rerun of Step 4 PC model, with some batteries replaced with CTs due to reliability concerns.	Yes
6	Rerun of Step 5 PC model with additional CTs forced in, if necessary and as determined from SERVM model, to ensure LOLE targets are met.	Yes
7	Rerun of Step 6 PC model with nuclear capacity and/or contract capacity added in later years to reduce Energy Not Served (ENS).	Yes
8	Rerun of Step 7 PC model with solar additions levelized.	Yes

As will be discussed in more detail later in these comments, the Public Staff's investigation has resulted in the identification of several modeling issues that the Public Staff is recommending Duke correct by running a modified portfolio (Portfolio 5, or P5).

Carbon Baseline and Compliance with Interim and 2050 Targets

Proposed Carbon Plan Appendix A (Carbon Baseline and Accounting) provides Duke's method for: (1) determining its level of CO_2 emissions in 2005; (2) calculating the reduction in CO_2 emitted by its generating facilities; and (3) quantifying and verifying CO_2 offsets. In calculating its 2005 baseline and compliance with emissions targets, Duke explained that it would account only for CO_2 emissions, and not for other greenhouse gases. It further explained that it would not include CO_2 emissions from electric generating facilities located outside the state of North Carolina. Duke included three categories of generation in its baseline: generation owned by Duke, generation operated by Duke, and generation operated on behalf of Duke.

To set the 2005 CO_2 emissions baseline, Duke utilized the United States Environmental Protection Agency's Emission and Generation Resource Integrated Database (eGRID). The Public Staff has corresponded with The North Carolina Department of Environmental Quality's Division of Air Quality, which agrees with Duke's carbon baseline and accounting of CO_2 emissions. Duke's North Carolina CO_2 emissions were approximately 76 million tons in 2005 and approximately 41 million tons in 2021, a 46% reduction. To achieve a 70% reduction, Duke will need to reduce CO_2 emissions to approximately 23 million tons per year.

In 2005, DEP co-owned the Roxboro plant and Mayo plant generating facilities with the North Carolina Eastern Municipal Power Agency, which possessed ownership interests in these plants of 12.94% and 16.17%, respectively. Duke did not partially operate any generating facilities in North Carolina at the time. Currently, Duke does not co-own or partially operate any generating facilities in North Carolina. The Rowan County CC facility and several co-generators and small power facilities sell their output to Duke and are part of its CO_2 baseline.

Duke identified a need for Commission guidance concerning the question of whether the Commission will consider CO_2 emissions from out-of-state generating resources selected to be part of the Carbon Plan as if such emissions occurred in North Carolina, given the fact that Duke has dual-state systems. In its model, Duke assumed that new CO_2 emitting resources would be located in North Carolina but stated that it would consider siting new resources inside or outside of the state depending upon the suitability of the site.

Finally, Section 110.9 allows Duke to use carbon offsets for up to five percent of its 2050 carbon neutrality goal. While Duke notes that it currently has no plans to use carbon offsets to meet the 2050 target, it also explains that, before using any carbon offsets in the future, it would first propose a calculation methodology for regulatory approval. The Public Staff does not object to this approach and will review future detailed plans as Duke proposes them.

Load Forecast

Load forecasting is the process of predicting future energy needs, including peak demand. As with previous IRPs, the Public Staff has reviewed the 15-year peak and energy forecasts (2023 to 2037) of the Companies both before and after the impacts of DSM and Utility Energy Efficiency (UEE). Given the extended period of the proposed Carbon Plan to 2050, the Public Staff also reviewed the hourly load forecasts incorporated in the EnCompass model. As in prior IRPs, DEC and DEP employed econometric and statistical adjusted end-use analytical models to forecast hourly energy sales for residential, commercial, industrial, and wholesale customers.

DEC's and DEP's dominant seasonal peak has historically occurred during summer afternoons between the hours ending 3:00 p.m. and 5:00 p.m. However, the larger amount of solar generation in DEP's service area and the reduced saturation of residential natural gas heating customers have contributed to DEP's dominant peak shifting to the winter season. From 2015 through 2019, DEP's annual peaks have all occurred at the hour ending 8:00 a.m. during either January or February. Meanwhile, during this same period, DEC has realized a more balanced mixture, with annual peaks occurring during winter in some years and summer in other years. DEC's summer peaks are predicted to be the dominant peak throughout the forecast; however, even though DEC is a summer peaking utility, it operates as a winter planning utility.[19]

This section presents the Public Staff's forecasted annual summer peak demands for DEC and winter peak demands for DEP and their annual energy sales over the next 15 years (as done in prior IRPs) followed by a review of forecasted growth through 2050. The annual peak and energy sales forecasts are based on load data found in the Proposed Carbon Plan's Tables F-21 and F-22, which is the hourly load data used in the EnCompass model and based on Duke's responses to various data requests.

Duke Energy Carolinas, LLC

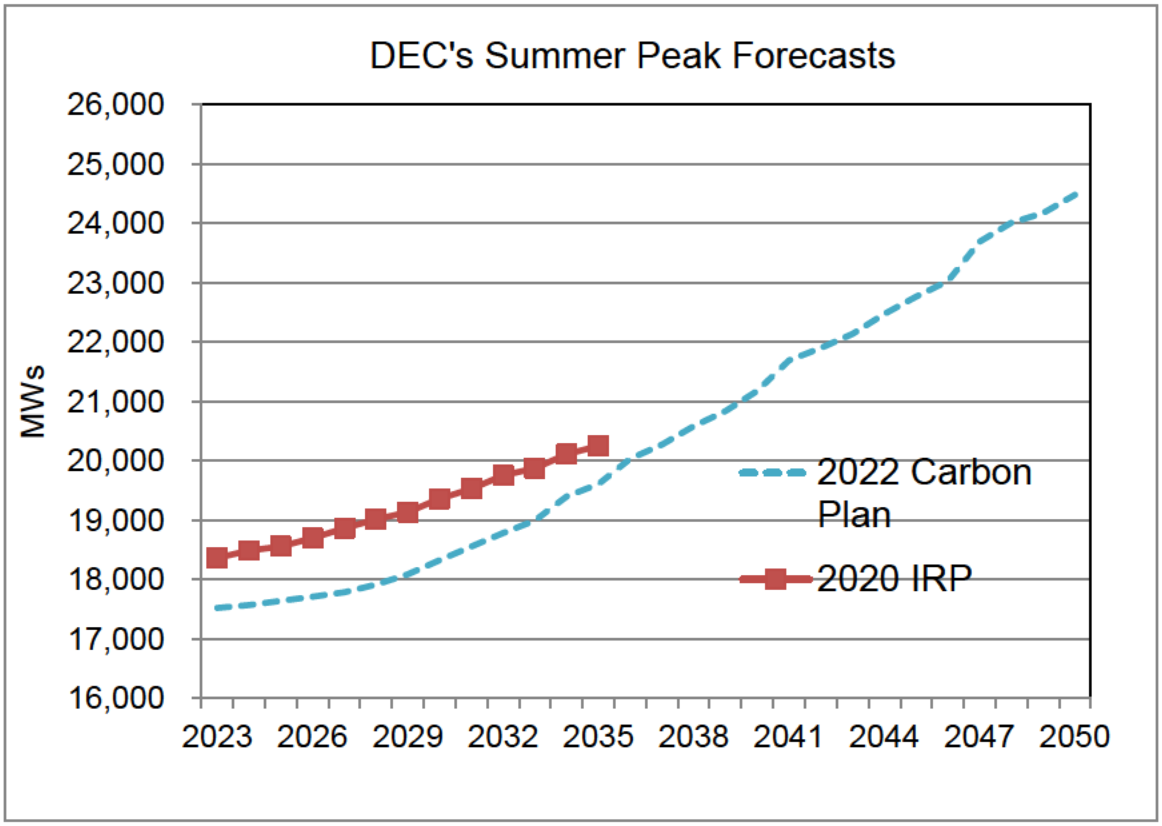
DEC's forecasted summer peak loads, after incorporating load reductions associated with new UEE programs,[20] and the additional peak demand associated with electric vehicle (EV) charging, reflect a compound average growth rate (CAGR) of one percent over the forecast years of 2023 through 2037. Thereafter, the annual growth rate increases to 1.2% over the extended period through 2050. While the new UEE efforts will reduce total load, EV energy sales will add 552 MW

[19] *See* Proposed Carbon Plan Appendix E at 69.

[20] Includes savings with the Critical Peak Pricing, integrated volt-VAR control programs, and Net Metering.

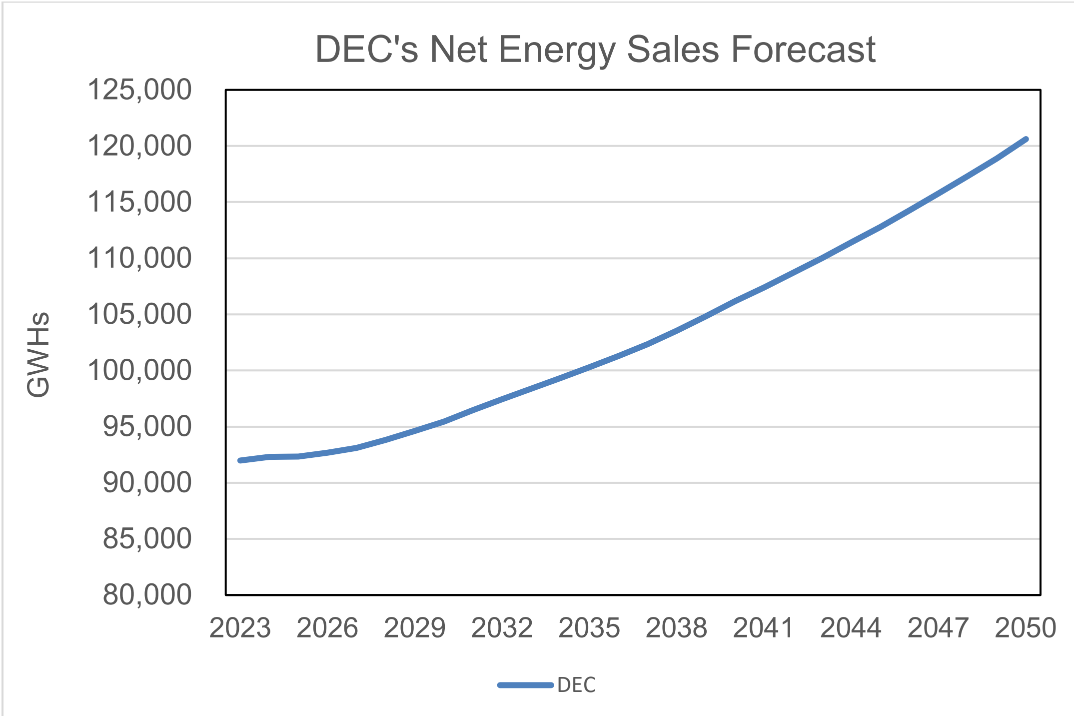
to the summer peak demand in 2037 and 1,932 MW to the peak demand by 2050. Without the added demand from EV energy sales, DEC's CAGR would be 0.9% through 2037 and 2050. In comparison, DEC forecasted a 0.8% CAGR in Docket No. E-100, Sub 163 (2020 IRP). The Proposed Carbon Plan's average annual growth in summer demand through 2037 is 197 MW and 258 MW for the extended period through 2050. To add historical context, for the last ten years, DEC's weather-normalized peaks have grown at a 0.4% CAGR and actual summer peaks have shown zero load growth. Figure 2 below summarizes DEC's summer peak forecast.

Figure 2: Summer Peak Forecasts for DEC



DEC forecasts that its energy sales, net of UEE savings, but including the energy demands necessitated by increased EV use, will grow at a CAGR of 0.8% for the period through 2037. Thereafter, the energy sales are projected to increase to a 1.0% CAGR over the extended period through 2050. Both growth rates are significantly higher than the 0.5% growth rate DEC forecast in its 2020 IRP. Figure 3 below summarizes DEC's net energy sales forecast.

Figure 3: Net Energy Sales Forecast for DEC



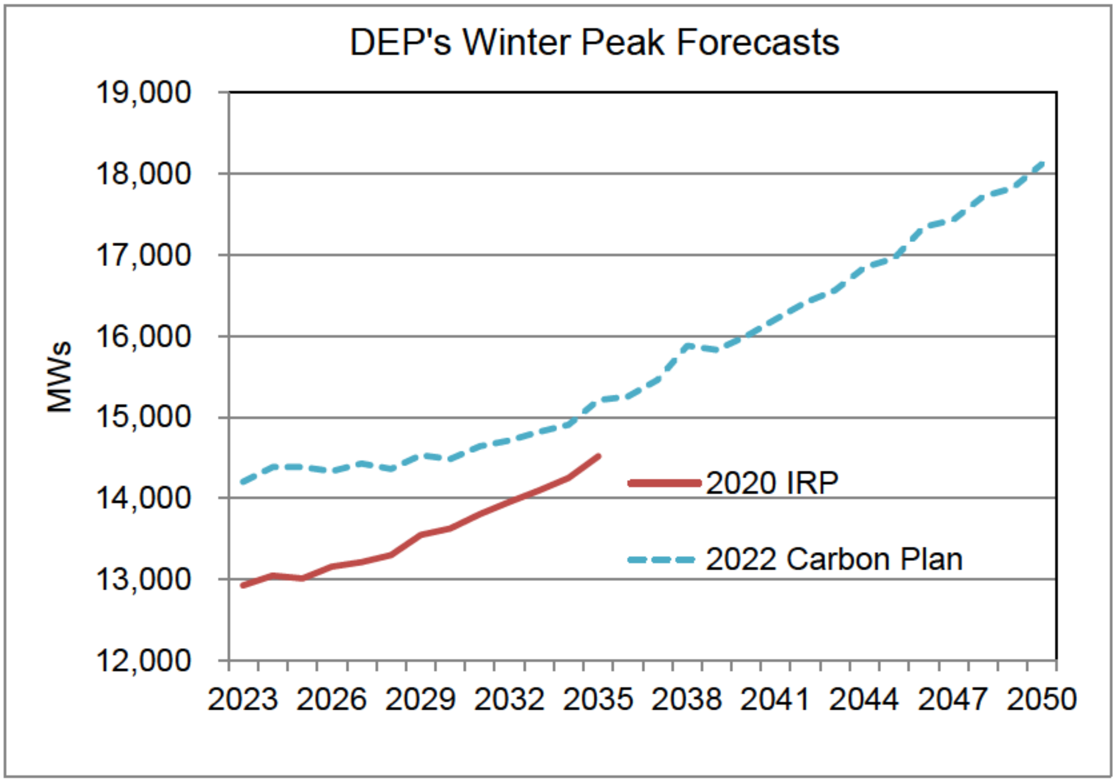
Load factor is a ratio comparing average load to peak load and is calculated by dividing a utility's energy sales by the utility's peak load, which is multiplied by 8,760 (the number of hours in a year). Higher load factors reflect greater energy sales relative to fixed production plant costs, whereas a declining load factor tends to result in higher costs. DEC projects its load factor to be approximately 60% over the next 7 years, falling to 56% by 2050. This decrease in load factor is largely explained by the increase in summer peak demand resulting from EV charging.

Duke Energy Progress, LLC

DEP's forecasted winter peak loads, after incorporating load reductions associated with new UEE programs[21] and the additional peak demand associated with EV charging, reflect a CAGR of 0.6% over the forecast years of 2023 through 2037. Thereafter, the annual growth rate increases to 0.9% over the extended period through 2050. While the new UEE efforts will reduce total load, EV energy sales will add 57 MW to the winter peak demand in 2037 and 146 MW to the peak by 2050. Customers are expected to charge their EVs during off-peak hours (e.g., overnight), lessening the impact of EV-related load in winter peaking systems. Accordingly, even without the added demand from EV energy sales, DEP's CAGR is forecasted to remain at 0.6% through 2037 and 0.9% through 2050 because DEP is a winter peaking system. In comparison, DEP forecast a 0.8% CAGR in its 2020 IRP. The Proposed Carbon Plan's average annual growth in winter demand through 2037 is 113 MW and 157 MW for the extended period through 2050. For the last ten years, DEP's weather-normalized peaks have grown at a 1.0% CAGR and actual winter peaks have shown a 0.4% CAGR. Figure 4 below summarizes DEP's winter peak forecast.

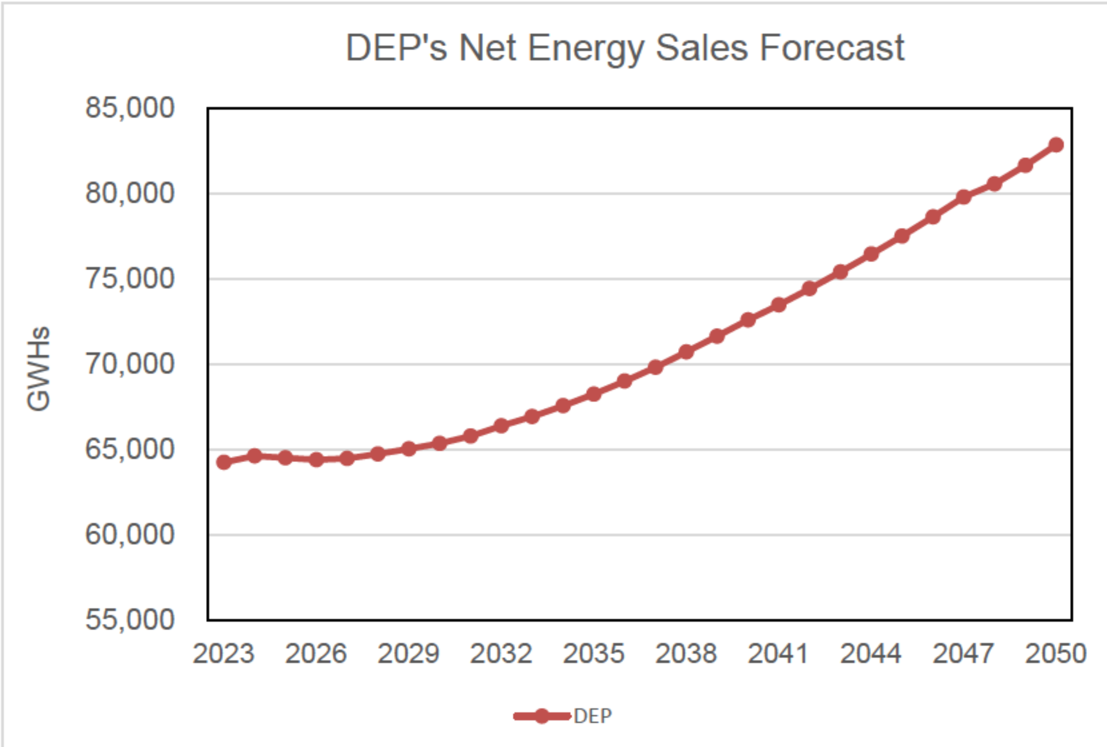
[21] Includes savings from Critical Peak Pricing, integrated volt-VAR control programs, and Net Metering.

Figure 4: Winter Peak Forecast for DEC



DEP forecasts its energy sales, net of UEE savings, but including the energy demands necessitated by increased EV use, will grow at a CAGR of 0.6% for the period through 2037, increasing to a 0.9% CAGR over the extended period through 2050. These forecasts are comparable to DEP's 0.8% CAGR growth forecast in its 2020 IRP. Figure 5 below summarizes DEP's net energy sales forecast.

Figure 5: Net Energy Sales Forecast for DEC



In addition, DEP projects its load factor to be approximately 52% over the next 15 years, comparable to the 51% load factor projected in its 2020 IRP.

Table 6 below summarizes the forecasted growth rates for DEC's and DEP's system peak demand and energy sales. The Public Staff has reviewed the econometric equations underlying the forecasts for the Companies and believes that their economic, weather-related, and demographic assumptions are reasonable and consistent with prior IRPs.

Table 5: Peak and Energy Sales Growth Rates including UEE, Net Energy Metering, and EVs

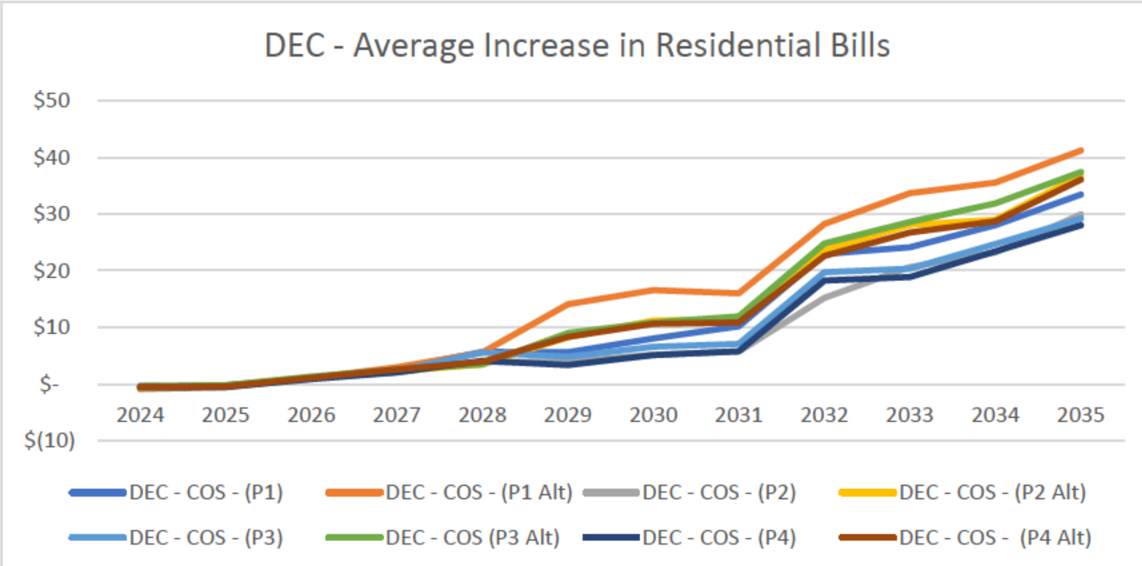
BA	Time Period	Summer Peak	Winter Peak	Energy Sales	Annual Summer MW Growth
DEC	2023-2037	1.0%	0.8%	0.8%	197
	2023-2050	1.2%	1.0%	1.0%	258
DEP	2023-2037	0.8%	0.6%	0.6%	109
	2023-2050	1.1%	0.9%	0.9%	155

Based on its investigation, the Public Staff concludes that Duke's 2022 peak demand and energy forecasts are reasonable for planning purposes.

Grid Edge Programs

In the Proposed Carbon Plan, Duke's load forecast incorporates the traditional components of UEE, EV, and Net Energy Metering (NEM) impacts in determining the net load forecast. The Proposed Carbon Plan also incorporates integrated volt-VAR control (IVVC) and time-of-use (TOU) rate designs, with each of these components playing a critical role in developing the load forecast. Duke's presentation of its Grid Edge programs further illustrates a high level of uncertainty in the load forecast itself. The Proposed Carbon Plan introduces several “program enablers/signposts” that the Public Staff believes require individual Commission approval or legislative changes before implementation. While the Companies’ load forecasts are relatively consistent with the approaches used in recent IRPs, the speculative and undeveloped nature of some of the Grid Edge assumptions creates uncertainty as to the accuracy of the load forecasts and their impact on Duke’s modeling. If these assumptions have not been appropriately assessed and incorporated, both Companies’ projected need for capacity resources within the Proposed Carbon Plan may be distorted. At present, however, the impacts of these policy enablers/signposts are not material to the load forecast in the Proposed Carbon Plan, which gives the Commission time to evaluate each of the policy enablers/signposts and their impacts on cost of service. Even so, the first significant increases in capital costs identified in the Proposed Carbon Plan’s portfolios are not expected to exert a material impact on the PVRR and customer bills until after 2028, as illustrated in Figure 6 below. DEP’s residential bill impacts increase similarly over time.

Figure 6: Average Increase in Residential Bills, DEC



Duke established three primary Grid Edge categories—programs that: (1) empower customers to reduce CO_2 (UEE, clean energy, and NEM); (2) manage the electric system to reduce CO2 (rate designs, demand response, Conservation Voltage Reduction/IVVC, and EVs); and (3) transform the electric system to enable CO2 reduction (SOG and advanced communication systems). While each of these categories has its own impact on load forecasting and capacity resources, the largest enablers are UEE, demand response, NEM, EVs, and rate designs, which are discussed in more detail below.

Utility Energy Efficiency

Duke has traditionally relied on its Market Potential Study (MPS) to establish a benchmark for new EE measures and savings. However, the Proposed Carbon

Plan deviates from the traditional approach and has hard-coded the achievement of at least a one percent reduction in retail sales, contrary to the achievable reductions projected in its MPS for measure/program development. Duke acknowledges that "this target reflects an aggressive long-term forecast of EE savings that is more than double the level assumed in the Companies' 2020 IRP."[22] Most recently, DEC achieved a 0.8% reduction in kWh sales from EE,[23] while DEP achieved a reduction of 0.7%.[24] As can be observed from Figure 7 and Figure 8 below, an increase in EE savings to 1% of both total and available sales would be substantial, particularly after 2030. Duke should provide further insight into the policy changes that it envisions as necessary to reach this 1% target. However, it appears to the Public Staff that achievement of this target would require a number of legislative and regulatory changes, including changes that would affect the Companies' ability to develop these EE programs in a cost-effective manner. Accomplishment of this target would also require far greater customer adoption, most notably greatly increasing the EE savings from industrial customers that are eligible to opt-out or are currently opted-out of participation in utility-sponsored DSM and EE programs.

[22] *See* Proposed Carbon Plan Appendix G at 5.

[23] *See* Duke's response to SACE DR1-12 in Docket No. E-7, Sub 1265.

[24] *See* Duke's response to SACE DR1-20 in Docket No. E-2, Sub 1273.

Figure 7 and Figure 8 below illustrate the disparity between DEC's and DEP's three UEE forecasts modeled for the Carbon Plan. The Base UEE forecast (Low Case assumption) represents the "Achievable Potential" determined from the Companies' MPS attached as Attachment IV to their filing.[25] In their second UEE forecast, the Companies modeled the target of a reduction of one percent of prior year retail sales (minus opt-out), labeled as "1% of Available Sales." This model is the forecast chosen for inclusion in the Net Load Forecast. Last, the Companies created a UEE forecast reflecting a reduction of 1% of prior year retail sales (including opt-out). This model is labeled as "1% of Total Sales" and is illustrated by the following figures developed from Duke's response to a discovery request.

[25] In the Companies' MPS, both Companies went beyond the "Achievable Potential" and determined "Program Potential" to better demonstrate the true potential of their portfolio.

Figure 7: Utility Energy Efficiency in DEC

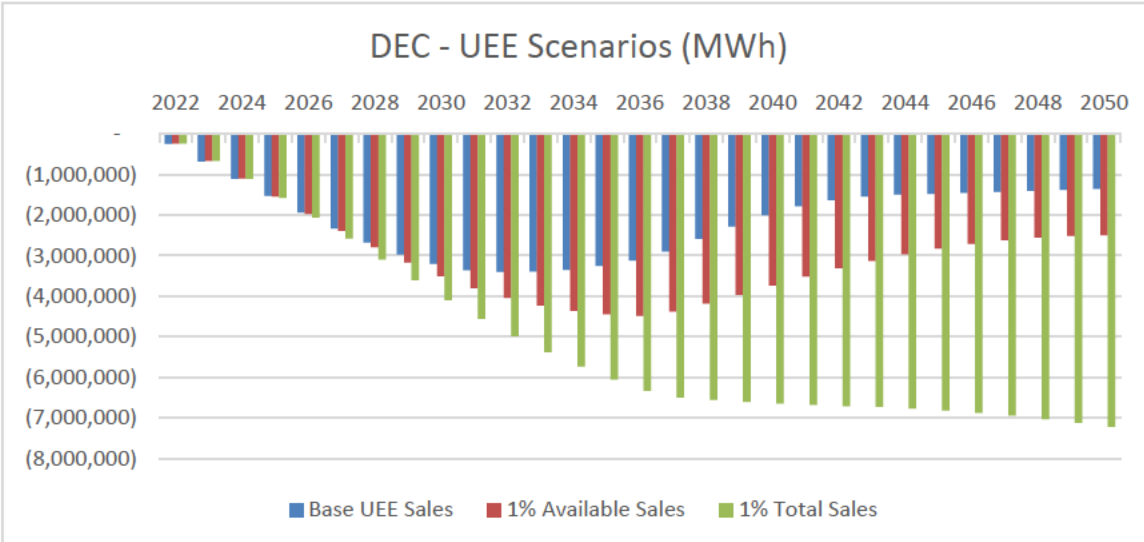
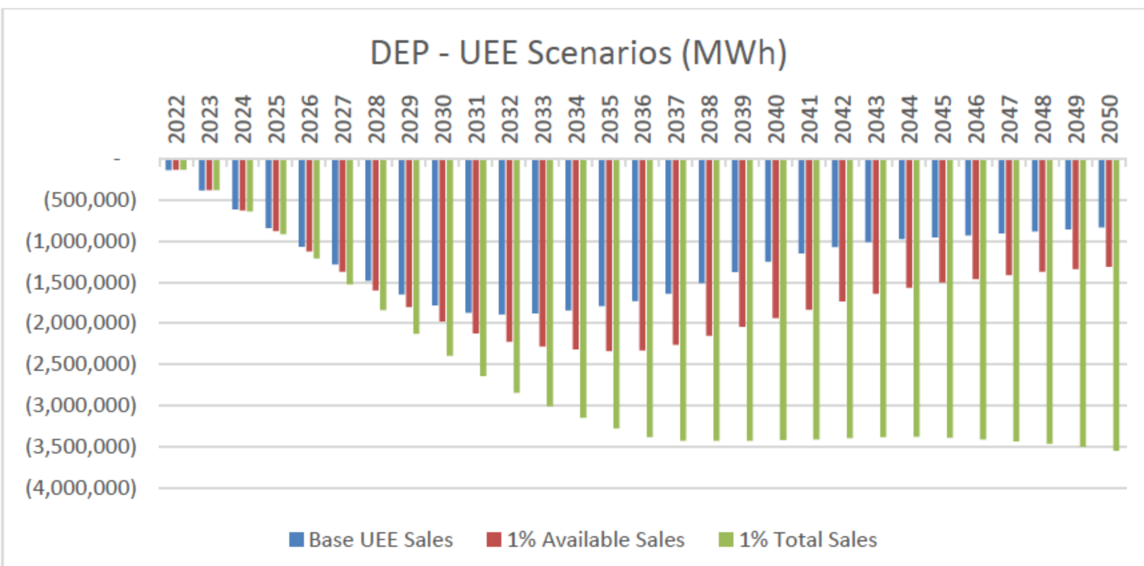


Figure 8: Utility Energy Efficiency in DEP



The figures clearly illustrate the formidable task ahead for Duke in increasing UEE from its current level. While Duke has proposed actions and enablers to achieve the one percent of Available Sales goal, it has recognized certain barriers of entry that, if overcome, could help achieve its goal.

The proposed enablers as discussed on pages 12 through 15 in Proposed Carbon Plan Appendix G and the Public Staff's responses are as follows.

<u>EE Cost-Benefit Modification</u>: Duke proposes to change how cost-effectiveness is calculated. This change would require a thorough study of the impact on cost recovery, the level of bonus incentives granted to Duke for verified EE savings, and goals for achieving certain energy reduction. It would also call into question the inputs used in the calculation to address non-energy benefits or the impact of Duke's avoided costs on the value of those benefits. The Commission has well-established cost-effectiveness tests and methods of calculation set out in the DSM/EE Mechanism, and any changes would require a thorough review of the DSM/EE Mechanism and Commission approval.

<u>As-Found Baseline for EE measures</u>: Duke proposes to offer another means to calculate energy savings in addition to the traditional "baseline method" that has been the mainstay method for most of Duke's EE portfolio. The "as-found" method uses the difference between the energy usage associated with the EE measure and the energy usage associated with the "as-found" measure (the old

appliance/measure that is replaced) when the new EE measure is installed. Traditional recognition of energy savings using the "baseline method" has been based on the difference between the EE measure and the energy consumption of the baseline measure consistent with the federal appliance standards or building codes in effect at the time the EE measure was installed regardless of the energy consumption of the appliance/measure that was replaced. The Public Staff has recognized the validity of the "as-found" method for program measures where there were no clear efficiency standards. Both methods are appropriate for Carbon Plan compliance purposes.

However, Duke should not be rewarded solely for persuading customers to adopt a measure sooner than they would have otherwise. If customers choose to replace a less efficient measure sooner than they would have, they still could not install a new measure that was less efficient than the standard requires. In other words, the timing is irrelevant to the transaction. Either way, the customer would be required to install a measure that complied with the minimum standard in effect at the time of replacement and would be getting a more efficient appliance.

If cost recovery based on "as-found" savings is to be considered on a broader scale or as a substitute for the baseline method, such consideration should only occur in the context of a cost recovery mechanism review that would review all factors related to program approval, cost-effectiveness, and cost recovery, including the PPI and PRI percentages. Further, there should be consideration of a limit on the use of the "as-found" savings, given that the older appliance or other measure likely would have been replaced with, at a minimum, a standard efficiency appliance or measure at some point in the planning horizon.

Code Compliance for Non-Lighting: Similar to the previous two enablers, Duke contemplates incentivizing early replacement of non-lighting measures to accelerate adoption of non-lighting measures that bring these measures up to code. The Public Staff's position on this proposal is the same as for the "as-found" savings discussed above.

Advance Codes and Standards Adoption: Duke hopes to encourage non-residential customers to meet existing energy codes in place at the time of new construction or by renovating existing construction. This plan is similar to the "as-found" savings discussed above.

Duke's efforts to address these barriers to its achievement of its EE targets are worthy of consideration. However, Duke has not provided a concrete plan for addressing these barriers and improving EE savings. Moreover, the energy savings attributable to the removal of each barrier have not been calculated or incorporated into the modeling. The Companies instead forced a hard-coded value of one percent into the model, increasing the energy reductions of all EE programs until the one percent threshold is achieved. Additional low-income programs and funding, increasing participant incentives, and on-tariff financing are three options Duke cites as ways to overcome these barriers. However, the impacts to program costs, NLR, PPI, and PRI incentives, or cost-effectiveness that will result from increasing EE savings to achieve a one percent target remain unclear.

The Public Staff also notes two items that are not discussed in the Proposed Carbon Plan. The first is related to the Companies' continued heavy reliance on behavioral-related EE programs. The current five-year forecast for both Companies has annual increases in the percentage of energy savings attributable to its behavioral programs in the range of 50% to 80%. Second, the Companies do not discuss market transformation in their portfolios. The Companies' forecasts simply assume that all technologies currently included in the portfolio today will be eligible technologies going forward. The Companies should acknowledge technologies that could experience market transformation. Whether market transformation is revealed through the Evaluation, Measurement, and Valuation process or occurs by modernizing the grid to improve the customer experience, EE savings will be diminished as determined by current cost recovery mechanisms. Both behaviorally oriented savings and savings occurring after market transformation eventually become part of the base load forecast, not the UEE forecast.

Demand Response

Demand response and other DSM programs have traditionally been treated in IRPs as capacity resources, primarily intended for limited use during times of stress to the systems. The Proposed Carbon Plan appropriately continues this same treatment.

However, the Proposed Carbon Plan shifts from a focus on peak shaving to one of "load shaping." The purpose of this change in focus is to plan for capacity resources that either are designed to reduce or encourage loads that are more responsive to system conditions and needs. Duke classifies these resources into two categories: "emergency" resources to respond to system reliability conditions, and "flexible" resources to respond to more routine changes in system conditions.

Much of Duke's existing demand response resources are "emergency" resources. Batteries, standby generators, thermostats, and water heaters that can respond to Company signals are a few examples of these small, individual resources. Non-residential demand response resources are well-established as emergency resources but may not be conducive to more frequent interruptions of service.

The Proposed Carbon Plan has five areas in which future opportunities for new demand response may exist:

- Building Code Changes: This initiative incorporates electricity demand management into building standards. Examples include controllable water heaters, smart panels that would enable EV charging and other managed loads.

- Summer Thermostat Capability: With the shift from summer planning to winter planning, the emphasis on summer load control and the value to the system as a resource has diminished. However, Duke asserts that summer load shaping capabilities remain viable resources, particularly for individual distribution circuits.

- Cost-Effectiveness Test Flexibility; Non-Residential Demand Response Rider and Flexible Demand Management Economics; and Customer Compensation and Convenience: These enablers are similar to each other in that they seek to modify the treatment of program costs, participant incentives, and program usage limitations to improve participation, provide greater incentives, and allow more system flexibility.

Stakeholders in the EE Collaborative have also expressed interest in developing new demand response programs and rate designs that provide a level of flexibility to Duke. However, as noted by Duke in Proposed Carbon Plan Appendix G at 31, some programs like water heater control programs struggle to demonstrate cost-effectiveness because of the small demand savings per participant. Duke also notes the reluctance of residential and small and medium commercial customers to participate in demand response programs that they perceive could create a level of physical discomfort they are unwilling tolerate. The balance between the level of participant incentives needed to increase participation, the frequency and degree of using demand response resources, and the level of discomfort participants are willing to tolerate, are just some of the factors to consider in program design. The Public Staff supports pilot programs to test the validity of these and other factors; however, that support must be grounded in a firm understanding that any new pilot must eventually demonstrate long-term cost effectiveness potential before becoming a permanent program offering.

The Public Staff also does not foresee any significant change in customer acceptance and behavior regarding demand response. Since these programs rely on customers <u>voluntarily participating</u>, balancing Duke's need for demand response with the need for maintaining and increasing participation is critical to any program's success and is particularly true for Duke's efforts to increase winter-oriented demand response. Duke states in Proposed Carbon Plan Appendix G at 27 that it needs to focus on reducing the winter peak demands to which the residential class tends to contribute significantly. Customers are unlikely to tolerate significant inconvenience resulting in cold indoor temperatures or limited hot water supply. Development of new flexible load shaping programs with appropriate incentives may encourage residential customer participation.

As described by Duke, the Public Staff does not take issue with any of these demand response enablers. However, none of the specific demand response proposals outlined in the Proposed Carbon Plan should be approved outside of the individual program approval process. Program applications should demonstrate cost-effectiveness and comport with Commission Rules R8-68 and R8-69. Any pilot program submitted for approval should be based on sound estimates of cost-effectiveness and be of sufficient scale and scope to provide meaningful data for Duke to develop a full-scale program.

Net Energy Metering

Duke also included NEM as a Grid Edge program that would further support its decarbonization targets. The Public Staff has reviewed the forecast assumptions regarding NEM growth and, at this time, has no issue with the assumptions used to develop the NEM forecast, including the Companies' estimated incremental NEM capacity growth of approximately 575 MW (system) for DEC and 307 MW (system) for DEP by calendar year 2035.

Additionally, Duke relies on its two pending filings[26] as justification: Docket No. E-100, Sub 180, "Solar Choice Net Metering," and Docket Nos. E-2, Sub 1287 and E-7, Sub 1261, "$mart Saver Solar." The Public Staff requests that the Commission take judicial notice of the Public Staff's comments filed in those dockets. The Public Staff supports approval of the Solar Choice Net Metering proposal as described in its comments filed in Docket No. E-100, Sub 180, but recommends the Commission deny approval of the $mart Saver Solar Program as an EE Program. However, in its comments, the Public Staff proposed that Duke review the potential of providing a rebate for the installation of residential solar if it is a resource that could assist Duke in achieving a least cost Carbon Plan.

Electric Vehicles

The Proposed Carbon Plan includes both plug-in-hybrid vehicles and electric vehicles in the EV load forecasts. Duke's EV load forecasts appear to be reasonable for the purposes of developing the Commission's Carbon Plan. The EV market is developing and has the potential to introduce significant amounts of additional load in the coming years. Since this market is nascent, the times of day at which the load will be placed on the system are largely unknown. Duke has several programs currently underway studying the impacts of EVs on the grid and

[26] Solar Choice Net Metering was originally filed in Docket Nos. E-2, Sub 1219 and E-7, Sub 1214 but was transferred to Docket No. E-100, Sub 180, and the $mart Saver Solar Program was filed in Docket Nos. E-2, Sub 1287 and E-7, Sub 1261.

customer responses to those EV-specific programs. EV load is unique in the way that it can shift throughout the day, particularly with managed charging programs. Additionally, rates and programs that Duke is implementing now can shape customers' charging behaviors and habits, rather than waiting to implement new rates after EV adoption is more mature and customers have established charging behaviors. By managing the charging behaviors of customers and shifting the load away from peak periods and times when ramping resources are needed, Duke can avoid having to serve EV load with more carbon intensive resources operating during peak times.

Duke has not included the impacts of EV-specific programs and rate schedules in its EV load forecast due to the uncertainty of customer response to these programs. Duke's exclusion of these impacts is not unreasonable at this time, but the EV demand has been modeled as unmanaged and may forecast significant EV charging demand during peak hours, despite Duke's efforts to induce managed charging. For example, without any incentives to do otherwise, residential customers are likely to begin charging their EVs when they arrive home from work on any given day of the week. Duke's inclusion of its estimate of unmanaged EV load in future years shows that the timing of this load could increase the peak demand. The Companies have used a mid-level forecast for EV adoption rates but forecast a high contribution to afternoon peaks and ramping. Due to the load management capabilities of EVs, a moderate adoption scenario and high contribution to peak is unlikely to occur. With proper price signals, EV owners would be incentivized to delay their charging until off peak hours. Failing to properly manage this new type of load could result in increased system peaks and acceleration of the need for new system resources in the future.

To help illustrate this increase, Figure 9 and Figure 10 below show the projected light duty EV summer average hourly loads for 2023 through 2030. Overlayed with the load shapes is the percent of hourly nameplate output for a typical sunny summer day, and shaded regions represent the critical peak pricing summer discount period and summer peak pricing time periods. As these figures illustrate, the solar generation begins to decrease in the afternoon before the peak EV load. Additionally, the peak EV load occurs through the peak pricing periods. Implementing critical peak pricing for EV owners could shift load from these high demand periods and increase the EV loads during the early morning hours. The Companies should continue to study consumer EV charging behaviors, market trends, and continue to develop rates and programs that encourage managed charging behaviors.

Figure 9: DEP Light Duty EV Summer Average Hourly Demand

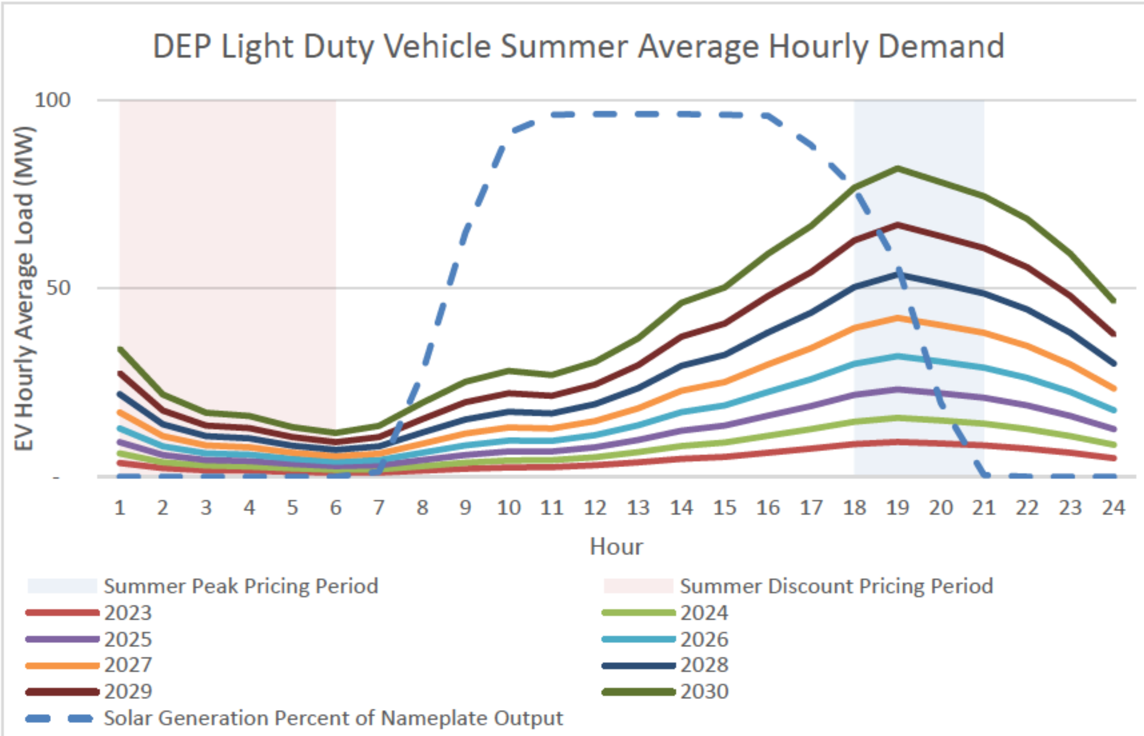
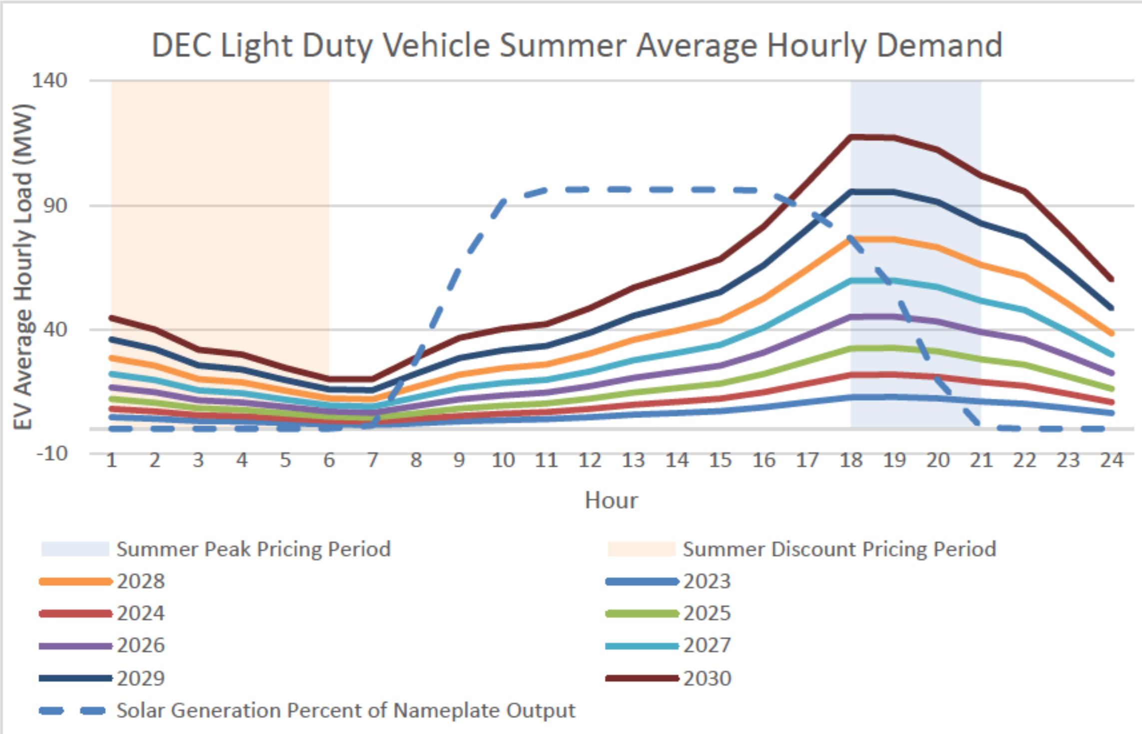


Figure 10: DEC Light Duty EV Summer Average Hourly Demand



Rate Designs

Duke's Comprehensive Rate Study recently concluded with the filing of their "Comprehensive Rate Design Study Roadmap" [27] This stakeholder process involved several stakeholders who offered rate design proposals, some of which Duke highlighted in the Proposed Carbon Plan. Stakeholders presented several proposals during those stakeholder meetings that could provide new rate design opportunities such as more TOU and dynamic pricing strategies and new designs

[27] Duke filed its "Comprehensive Rate Design Study Roadmap" on March 31, 2022, in Docket Nos. E-2, Sub 1219 and E-7, Sub 1214.

based on marginal costs and non-firm loads. Some proposals were controversial and had little consensus. However, the Public Staff believes the proposals stemming from this stakeholder process should be explored, and if shown to improve system efficiency and avoid significant cost shifts between customer classes, they should, at a minimum, be offered on a pilot basis. Additional rate design opportunities are likely to be developed along with demand response programs, particularly around those focusing on residential winter peak demand reductions.

Another potential rate design is subscription rates where customers pay a flat or fixed amount for service. Duke suggests that such programs might be combined and coordinated with other energy management programs such as flexible load demand response, particularly for customers who seek bill certainty. Duke relies on its winter demand study[28] as the basis for possible program designs. One example cited by Duke is a residential fixed bill with peak time rebate structure that could be associated with electric HVAC, water heating, and cooking appliances. One concern with subscription-based or fixed bill rate designs is the potential to increase energy usage overall. Previous rate designs that allowed fixed bills demonstrated an increase in consumption and were eventually terminated by

[28] *See* Duke's "Winter Peak Targeted DSM Plan" filed January 19, 2022, in Docket No. E-100, Sub 165.

the Commission.[29] However, Duke has received Commission approval of an EV managed charging pilot that is a subscription-based rate design.[30]

As with demand response, the Public Staff currently does not oppose any of these proposals but does not recommend any of the specific rate design proposals in the Proposed Carbon Plan. Any such proposals should be fully reviewed as part of a program application.

Grid Edge Recommendations

The Public Staff recommends that the Commission:

1. Require a more reasonable UEE forecast in Duke's Net Load Forecast to be used in the Public Staff's recommended P5 and in future Carbon Plan filings, comparable to the forecast methodology of prior UEE forecasts in Duke's IRPs. The Low Case assumption provides a better estimation of the impacts to future load; therefore, the Public Staff recommends that Duke perform a transparent analysis in future Carbon Plans that clearly illustrates how: (1) these enablers might affect the load forecast; (2) the effects of market transformation; and (3) any other changes that might be considered in the context of a future MYRP;

[29] *See* the Commission's Order Ruling on Fixed Payment Programs dated March 14, 2008, in Docket Nos. E-2, Sub 847 and E-7, Sub 710.

[30] The Public Staff supported this pilot. *See* Order Approving Electric Vehicle Managed Charging Pilot Programs dated June 24, 2022, in Docket Nos. E-2, Sub 1291 and E-7, Sub 1266.

2. Deny Duke's request for approval of its proposed plan to update the utility system benefits and value of those benefits and require it be considered in a comprehensive DSM/EE Mechanism review with all components of the DSM/EE Mechanism considered together;
3. Address the appropriateness of using "as-found" savings for Carbon Plan compliance, and in a separate proceeding, how "as-found" savings would be treated for EE cost recovery purposes; and
4. Defer a decision on Duke's request to move forward with its Grid Edge programs and require Duke to file for approval of the individual programs in separate dockets and request a review of the EE Mechanism for any changes that would impact cost effectiveness, savings, or costs.

Commodities

Duke's Proposed Carbon Plan is highly dependent on fuel commodity prices. The Public Staff does not take significant issue with Duke's approach but does recommend modifications. For commodities (fuel sources) not specifically listed in this chapter, the Public Staff does not propose a change at this time.

<u>Natural Gas</u>

Each of the four portfolios in the Proposed Carbon Plan will increase Duke's current dependence on natural gas, affecting both large baseload combined cycle generators as well as intermediate and peaking combustion turbines. If Duke retires nearly 9 GW of dispatchable coal generation over the next decade as currently anticipated, and estimated forward natural gas price curves prove correct, Duke will rely on natural gas generation for decades into the future.

The current high price of natural gas was not forecasted when most of Duke's existing fleet of natural gas-fired generation was planned and constructed, and as a result, Duke is currently exposed to significant price volatility, especially Henry Hub (HHub) Zone 5 price volatility. However, the natural gas forecasts contained in the Proposed Carbon Plan affect capacity expansion starting around year 2026, well beyond the current price volatility. Figure 11 below compares the different natural gas price curves used in the Proposed Carbon Plan. As discussed later in this section, these fuel prices include the impact of hydrogen blending.

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The Public Staff has expressed concerns regarding future natural gas supply and deliverability in past dockets.[31] This issue is also extensively addressed by Duke in its Proposed Carbon Plan. Over the past year, development of new natural gas pipelines and deliverability to the Carolinas has continued in various stages. The MVP would bring Marcellus and Utica shale natural gas from West Virginia through Virginia to North Carolina once completed yet continues to have

[31] *See*, e.g., Docket No. E-100 Sub 165, 2020 IRP Comments of Public Staff, p. 91-94.

in-service delays.[32] An additional pipeline that may impact North Carolina is the MVP Southgate, a pipeline lateral of the main MVP line that would connect in Virginia and be routed into North Carolina. Given the continued uncertainty of the main MVP line and MVP Southgate's dependence on the main MVP line, the viability of MVP Southgate is uncertain.

Because of the continued uncertainty as to the completion of the MVP due to legal challenges, the Public Staff recommends that Dominion Zone South be disallowed at this time as a selectable fuel supply resource in Duke's primary portfolios.[33] Given the recent proposals for Williams Transco upgrade projects, however, the Public Staff supports the use of HHub Z4 and Z5 gas pricing for modeling purposes and planning. In the short term (pre-2030), HHub Z4 and Z5 natural gas prices have some disparity during the winter months; however, over time (post 2030), the winter natural gas price volatility of the two zones lessens.

The Public Staff recommends that Duke use a simple average of the HHub Z4 and Z5 price for existing and future CC plants but use the HHub Z5 pricing[34]

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[32] *See* MVP's Letter to the FERC "Request for Extension of Time." Requested in-service date to October 13, 2026. Document Accession #: 20220624-5132 filed June 24, 2022.

[33] On March 30, 2022, the Public Staff filed Supplemental Reply Comments in Docket No. E-100, Sub 165, recommending that the Commission direct Duke to utilize a limited Appalachian gas portfolio as the base case for its Proposed Carbon Plan.

[34] This approach of "averaging" is similar to Duke's current purchasing of natural gas and cost assignment within the Annual Fuel Riders. The EnCompass model could use a percent blending of two different fuel sources in order to maintain the integrity of the zonal pricing or a post process input linked to combined cycle generation units.

for CTs (intermediate and peaking generators) in the Public Staff's requested Portfolio 5. This will more accurately represent how Duke uses the natural gas system and will likely use it in the future. CC plants will most likely have firm natural gas supply procured well before commercial operation, enabling purchases from different gas zones and averaging of costs. Traditionally, CT gas demands are supplemented on an as-needed basis, exposing them to as-available non-firm Zone 5 pricing.

<u>Fuel Oil</u>

Fuel oil, or ultra-low sulfur diesel, is a backup fuel used to run certain generation during fuel constraints or initial starts. For example, a CT may need to use backup fuel in the event that the primary fuel is interrupted, or the primary fuel does not have firm transportation and is curtailed. Backup fuel has a higher carbon emittance rate per delivered unit of energy than the primary fuel source. The Public Staff does not take issue with the use of backup fuel, or the commodity price used for backup fuel. However, the Public Staff observes that the alternate portfolios, but not the Primary Portfolios, force new natural gas generation to burn fuel oil for the entire month of January. The Public Staff understands Duke's concerns regarding natural gas supply limitations during this peak winter month in the alternate portfolios and its reasons for incorporating these concerns into its modeling. However, the planned improvement projects by Williams Transco, including increased capacity, may significantly limit the need for fuel oil consumption for all natural gas plants.[35] Duke's modeling constraint in the alternate portfolios may therefore over-represent the use of fuel oil and overstate the increase in the amount of carbon emitted in every given year.

The Public Staff is unaware of an instance in which natural gas has been unavailable for an entire month. During extreme cold weather events, however, operational flow orders (OFO)[36] may occur and high natural gas prices could favor fuel oil over natural gas. Because of how EnCompass models this constraint, the Public Staff recommends that instead of forcing 100% use of fuel oil during January, a 20% fuel oil blend be modeled. The Public Staff further recommends that the primary portfolios use the 20% fuel oil blend as well, with this constraint applying only to new CTs, and not to CC plants. This approach would simulate the several-day period every January with high system loads and a high use of fuel oil (with its higher carbon emittance rate) but would more accurately reflect the lower CO_2 emissions that would result from a less-than-full month of fuel oil consumption. Duke should include both of these recommendations in P5, as well as in future Carbon Plan filings.

[35] The proposed upgrades will not allow an unlimited amount of natural gas delivery but will support at least two additional combined cycle generating plants.

[35] OFOs help maintain the operational integrity of natural gas pipelines. In addition, OFOs are a mechanism used by the natural gas pipeline owner in part to balance supply and demand scheduling and minimize natural gas supply imbalances.

Hydrogen

Green hydrogen (hereafter referred to as hydrogen) is likely the most controversial fuel modeled in the Proposed Carbon Plan given its production risks. While hydrogen is a carbon free fuel source, production risks (including the expense of production and lack of transportation infrastructure) make reliance on hydrogen highly speculative at this time. Further, Duke has not demonstrated that hydrogen is a least cost resource; rather, hydrogen was forced into the model. The Public Staff recommends that Duke remove all hydrogen from the base portfolios and rerun the model for the Public Staff's requested Portfolio P5. Hydrogen should be considered in an alternative portfolio analysis, rather than in the primary portfolios, until Duke and the hydrogen industry resolve uncertainty around development risk, deliverability, and cost. The Public Staff also recommends that the Commission order Duke to engage in discussions with natural gas providers concerning the costs and risks of using hydrogen (e.g., the feasibility of safely transporting hydrogen in higher percentage blending rates on the natural gas piping system without pipeline and pipeline equipment degradation), in addition to assessing the risks related to consumption at the generator site.

In the Proposed Carbon Plan, Duke modeled hydrogen in two ways: (1) gradual blending and increasing the ratio with respect to natural gas over time, starting in year 2035; and (2) building new CT generators that will use 100% hydrogen starting in year 2040. Duke has not demonstrated that hydrogen is an absolute need for the 2050 carbon neutrality goal, but Duke's planned use starting in year 2035 will impact resource selections well before that year. As stated above, Duke forced hydrogen fuel blending into the model and forced in its benefits by blending the price of hydrogen into the fundamental fuel price for natural gas, and by reducing the carbon emission rate of natural gas consumption to reflect various blending levels. The result of this blending on natural gas prices is shown in Figure 12; in later years, the fundamental price forecast for natural gas is increased as a result of this blending.

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In future Carbon Plans where hydrogen is blended with natural gas, Duke should utilize existing EnCompass tools to create separate fuel price forecasts and emission rates for hydrogen and natural gas and allow CCs and CTs to burn hydrogen as necessary to meet CO_2 emission requirements. This modeling would also provide a more transparent accounting of hydrogen demand in each portfolio.

The Public Staff acknowledges that hydrogen may be shown to be a beneficial fuel to achieve CO_2 reduction in the distant future, but it is currently not mature enough to include in the primary portfolios.

Portfolio Costs and Risks

Costs

In its Proposed Carbon Plan, Duke presents the combined PVRRs of each portfolio by 2050. As previously discussed, these PVRRs do not consider all costs that Duke ratepayers will likely face over the planning horizon. Costs that are common across all portfolios and not considered in the modeling, such as the fixed costs of existing generation plants, the RZTEP, and Duke's ongoing Grid Improvement Plan are not included. The PVRR is therefore a comparative analysis between portfolios that considers production costs, new generation and transmission capital costs, EE and DSM costs, capital costs and fixed O&M costs associated with coal plants, and fuel demand costs associated with natural gas pipeline contracts.

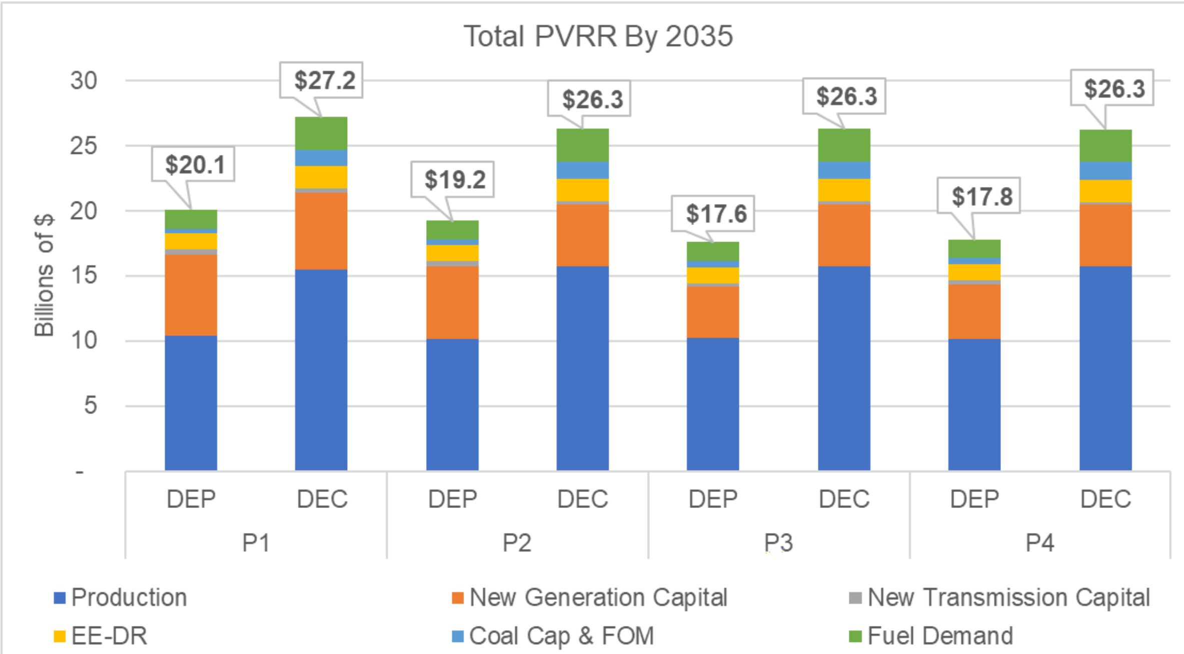
While this high-level view of portfolio costs is helpful in establishing which portfolio might be considered the least cost, reviewing the PVRR over the shorter term is also valuable. As Table 7 below shows, P3 is the least cost portfolio by 2035 and 2050, followed closely by P4. P2 is approximately 3.6% more expensive than P3, and P1 is significantly more expensive than P3 through 2035.

Table 6: PVRR of Each Portfolio, Relative to Least Cost Portfolio (LC)

Portfolio	PVRR 2035 ($B)	% Over LC	PVRR 2050 ($B)	% Over LC
P1	47.3	7.6%	101.1	6.2%
P2	45.5	3.6%	98.8	3.7%
P3	43.9	LC	95.2	LC
P4	44.1	0.3%	95.5	0.3%

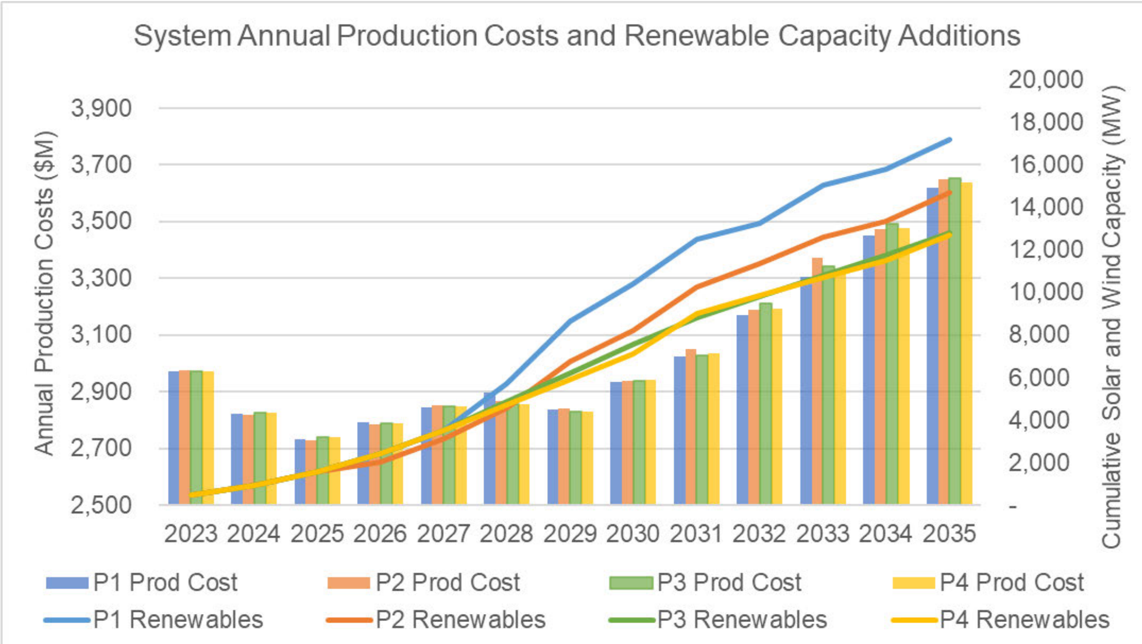
To provide additional nuance, Figure 13 below breaks out the system PVRR estimates by cost category and Company. By 2035, DEC does not show significant variation between the costs of P2, P3, and P4; these portfolios each have a PVRR of $26.3 billion. For DEP, the primary drivers of the higher costs associated with P1 and P2, relative to P3 and P4, are DEP's addition of significant incremental quantities of solar, wind, and battery storage capacity. Because of the rapid pace of resource additions, P1 and P2 are most sensitive to increases in transmission costs and increases in the capital costs of solar and battery storage. These portfolios are also most vulnerable to cost overruns, as expedited construction schedules for transmission outages may increase costs.

Figure 13: Total PVRR by 2035 Across all Portfolios



Theoretically, production costs should decline over time as a substantial amount of renewable capacity with zero fuel costs is added to the system; however, the PVRR analysis illustrates that this is not the case in Duke's Proposed Carbon Plan. Figure 14 below charts the annual production costs for each portfolio (truncated left axis and bar graphs) against the cumulative additions of solar and wind capacity (right axis, line graphs). Very few differences emerge between the annual production costs of each portfolio, despite the variance in cumulative renewables and decline in coal consumption.

Figure 14: System Annual Production Costs and Renewable Capacity Additions Across all Portfolios



While total fuel costs generally stay flat and decline over time, the driver for these increasing production costs appears to be fixed costs, which includes fixed O&M. Duke escalates these unit costs in the model by 2.5% per year. As seen in Figure 15 below, fixed costs increase dramatically, rising at least 1000% between 2022 and 2035 across all portfolios. This large increase is likely due to two factors: (1) fixed costs for existing units are not included in the model, therefore, early years (i.e., 2022 through 2035) have understated fixed costs; and (2) there are significant fixed costs associated with adding tens of thousands of MW of new solar, wind, and battery storage to the grid. As shown in Figure 16 below, it is clear that absent the dramatic increase in fixed costs, production costs would decline over time.

Figure 15: System Fixed Costs by Portfolio, 2023 through 2035

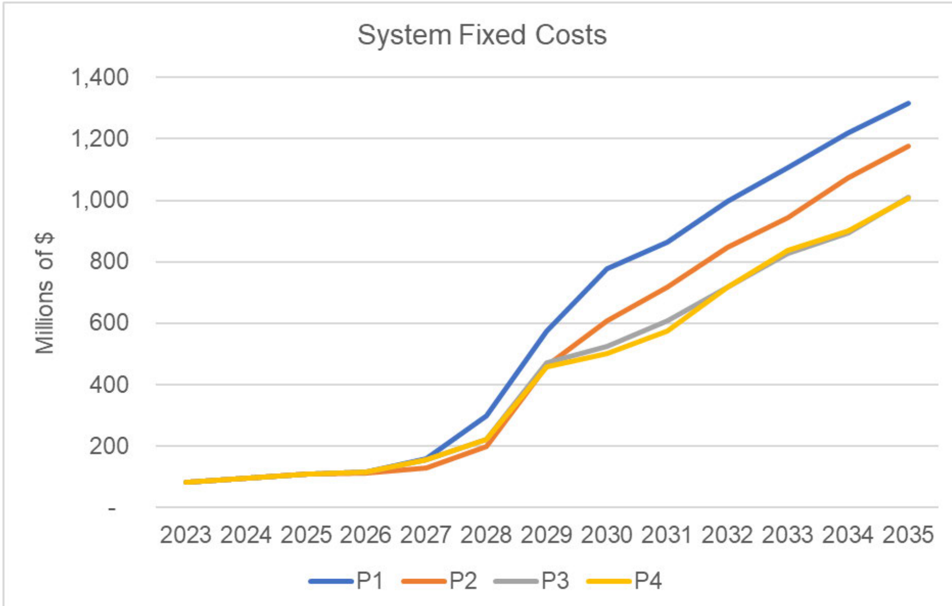
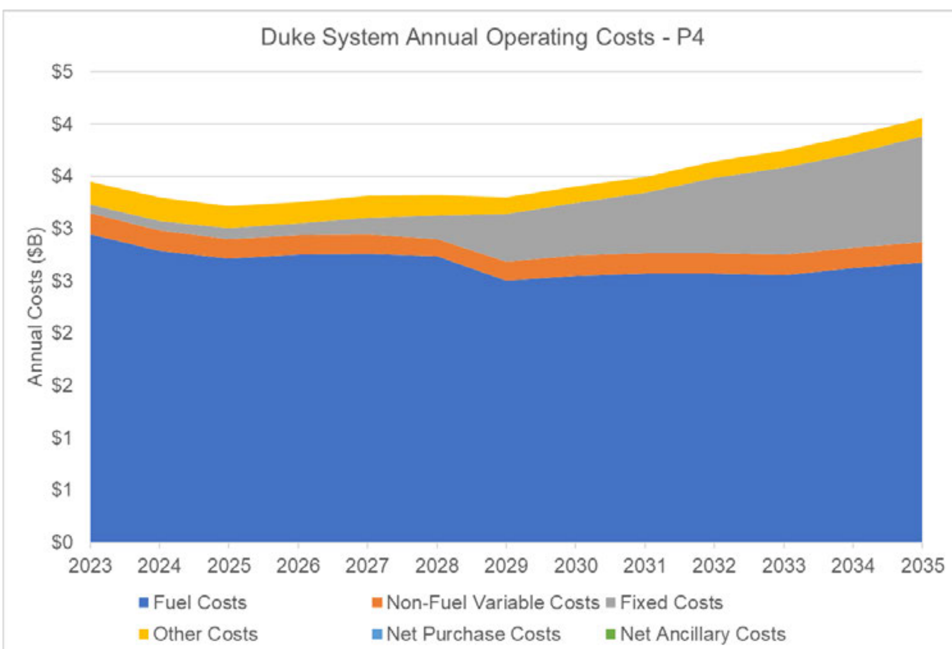


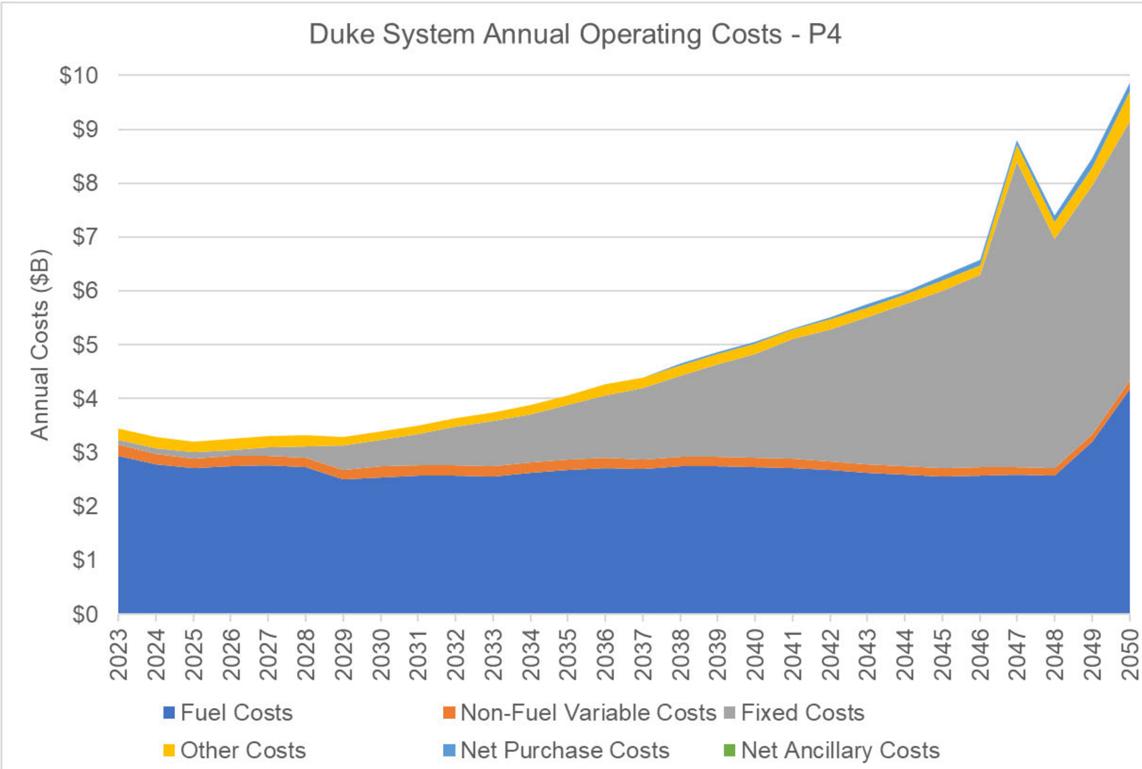
Figure 16: System Annual Operating Costs for Portfolio 4



Between 2035 and 2050, this increase in operating costs is even larger, as shown in Figure 17 below. Because the model did not include fixed costs for existing units, it is difficult to determine the extent to which the increase in operating costs are attributable to existing units. For this reason, the Public Staff recommends that in Duke's 2024 Carbon Plan filing, the Commission direct Duke to include fixed O&M costs for its existing units in its modeling. This should provide a more accurate analysis of production cost changes over time.

The annual production costs for each portfolio show a significant cost increase in 2047, which is evident in Figure 14. This increase represents a one-time fixed cost charge of approximately $1.78 billion, a 45% increase over expected fixed costs in that year. This significant fixed cost is for the conversion of Duke's CT and CC plants (those CT plants built before 2040 and all CC plants operating in 2047) to run on 100% hydrogen blend by 2050. This conversion requires: new hydrogen piping and manifolds; combustion hardware changes for maximum hydrogen operation, controls, instrumentation, and electrical components compatible with hydrogen operations; and enhanced system purging capabilities. The rise in fuel costs in 2049 and 2050 also reflect this conversion to hydrogen, as hydrogen is assumed to be more expensive than natural gas.

Figure 17: Duke System Annual Operating Costs for P4



One potentially material impact of the cost to convert to 100% hydrogen combustion is that when the model selects CCs in 2028, the model does not know that this significant fixed cost will be required in 2047. Because Duke optimized its capacity expansion model over an eight-year period rather than the full planning horizon,[37] the model does not have perfect foresight regarding fixed unit costs beyond each eight-year period. As such, it is difficult to determine whether the

[37] This decision was made largely to reduce model run times. Completing all capacity expansion models using a full optimization period creates a significantly more complex problem to solve and can extend model run times exponentially. Generally, the Public Staff does not take issue with the eight-year optimization period, although specific concerns such as these hydrogen conversion costs could be validated through a longer optimization period model run.

natural gas CCs selected in the late 2020s in both DEC and DEP would still be selected if the required costs of hydrogen conversion were known. While models with perfect foresight often make decisions that are not realistic in actual system operations, in this case, the model actually has more uncertainty as to future costs than Duke's system planners. In addition, this conversion is forced into the model without considering whether converting all CCs and CTs to run on 100% hydrogen is the least cost solution.

Duke must resolve the issue of unknown hydrogen conversion costs before it requests a Certificate of Public Convenience and Necessity (CPCN) for any new CTs and CCs that it has stated are necessary. Duke intends to file the CPCN applications for two CTs totaling 800 MW and one CC of 1,200 MW in 2023. The Public Staff recommends that the Commission direct Duke to submit a supplemental filing in this proceeding validating that the model would still select CCs if the hydrogen conversion costs are known at the time they are selected by the model, ideally by extending the optimization period used in its capacity expansion modeling for at least one capacity expansion model run.[38] This would be included in the P5 filing recommended by the Public Staff in these comments. In future Carbon Plans, the Public Staff recommends that Duke provide the model with the option to retire natural gas CCs and CTs in 2047 as an alternative to

[38] The extension of the optimization period in EnCompass, coupled with other changes requested by the Public Staff, can significantly increase the model run time and may not be practical for all capacity expansion model runs.

hydrogen conversion. The Public Staff is not recommending this change in this proceeding, as it would only impact the last few years of the model and would require more substantial modifications to the model.

Risks

As previously discussed, the Proposed Carbon Plan must be evaluated using multiple metrics. Estimated cost is one such metric, maintaining or enhancing reliability is another, and the risk to successfully executing a particular portfolio is an additional one. If a portfolio cannot be achieved due to unrealistic assumptions, compliance with interim carbon reduction goals may be delayed, and costs may increase due to delayed in-service dates or expedited construction schedules. It is important to not only assess each portfolio based on its PVRR estimate, but also on the likelihood of the specific resources selected being successfully constructed and brought online in the timeframe envisioned. While this high-level view of portfolio costs is helpful in establishing which portfolio might be considered the least cost, reviewing the PVRR over the shorter term is also valuable. As Table 7 shows, P3 is the least cost portfolio by 2035 and 2050, followed closely by P4. P2 is approximately 3.6% more expensive than P3, and P1 is significantly more expensive than P3 through 2035.

Table 8 below summarizes several key risk factors that exist across all four portfolios. The Public Staff selected these risk factors based on its review of the major differences between each portfolio, and the list is not exhaustive. For example, the 2032 expansion of the Bad Creek pumped hydro station is not identified in this list despite it being a major risk, given that it is present in each portfolio and the viability and feasibility of such an expansion is not certain.

Table 7:[39] Key Risk Factors Across Portfolios

Portfolio	Average Pace of Interconnections, MW, 2026-2030, for:		First Year for:		Total Natural Gas by 2035		% of DEC Load Served by DEP, 2035
	Solar	Batteries[40]	OSW	SMR	MW	% of Total Generation	
P1	High (~1,420)	High (~488)	2029	2032	3,559	21%	10.6%
P2	Moderate (~984)	Moderate (~284)	2029	2033	3,559	24%	13.0%
P3	Moderate (~1,014)	Moderate (~252)	None	2032	3,934	26%	10.8%
P4	Moderate (~925)	Low (~166)	2031	2032	3,559	26%	10.4%

Interconnection

The average pace of interconnections for solar and batteries represents a significant risk because the amount of capacity that must be interconnected to satisfy each portfolio is unprecedented in Duke's history in North Carolina. While Duke's interconnection queue has substantial amounts of solar, the amount that can be interconnected each year is dependent on multiple factors, including increasingly complex transmission studies and interconnections, the cost and

[39] Table 8 is identical to Table 1 and is reproduced here for ease of reference.

[40] Inclusive of batteries co-located with solar.

construction schedules for required transmission upgrades, and land availability. Duke's proposed RZTEP outlines a series of upgrades that it states is necessary to integrate the levels of solar called for in the Proposed Carbon Plan, but those upgrades would likely take years to construct, and other transmission upgrades would still be required in addition to the RZTEP in order to interconnect solar in the Carolinas.[41] Thus, higher levels of solar interconnections over the near term is a significant execution risk, even if Duke's RZTEP is approved as filed.

With respect to batteries, while some utilities across the country have been installing significant quantities of battery storage, Duke is still in the early stages of battery storage adoption. Each portfolio calls for less total battery storage capacity than solar capacity, but interconnection will likely still present issues. P1, for example, expects to add an average of 488 MW of battery storage annually from 2026 through 2030. However, only approximately 240 MW of active battery storage projects are currently in Duke's North Carolina interconnection queue, with no assurance of how much will actually be built.[42] It is also not clear whether battery storage projects can be dispatched by Duke in order to mitigate transmission congestion issues, or if they will instead contribute to congestion issues. The one

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[41] While the RZTEP projects are identified in multiple generator interconnection studies, those same studies often call for other upgrades not included in the RZTEP. These upgrades can be significant and would not necessarily be able to be constructed in parallel with the RZTEP upgrades.

[42] This figure does not include battery storage projects in South Carolina. It is based on an analysis of DEC's and DEP's quarterly queue status reports for the first quarter of 2022, filed in Docket No. E-100, Sub 101A.

100 MW battery storage project that has been studied in DEP's territory triggers no upgrades when discharging but would trigger $104.5 million of transmission upgrades when charging.[43] The need for battery storage is clear in the Proposed Carbon Plan portfolios, but until Duke has proven its battery storage development capabilities, a more ambitious interconnection schedule presents significant challenges.

Offshore Wind

Offshore wind is economically selected in every portfolio except P3, which prohibits its selection. While offshore wind is a rapidly maturing technology with significant deployment in Europe and Asia, it is still a relatively nascent technology in North America. Block Island Wind and Coastal Virginia Offshore Wind (CVOW) Pilot Project are the only two commercially operational offshore wind facilities in North America. The Block Island Project has five turbines with 30 MW total generation capacity. The community's desire to reduce its reliance on diesel generation aided in the relatively quick construction timeline from beginning construction in early 2015 to commercial operation in December 2016.

The CVOW Pilot Project has two turbines with a total of 12 MW of generation capacity which were installed under a research lease application to the

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[43] *See* the Generator Interconnection Facilities Study Report for Queue # 479, accessed at DEP's OASIS website https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/Q479_Fac_Study_r1.pdf (last accessed July 1, 2022).

United States Bureau of Ocean Energy Management (BOEM) in February 2013. The research lease was not fully approved until June 2019, which allowed construction to begin. Commercial operation of the two turbines was achieved in late 2020. The technical feasibility and construction of offshore wind in North America is complex and must be considered accordingly. For instance, while both commercial projects were constructed in a relatively short time span, the necessary transmission cables were less than 50 miles long. In addition, the regulatory and engineering work took over six years in the case of the CVOW – Pilot Project.

Another significant risk to offshore wind development in the US is the Jones Act, which places limitations on ships that carry cargo between US ports. In 2020, just over 30 ships specifically designed for turbine construction existed in the world. However, the Jones Act presents many logistical issues for using these ships for turbine construction because they would not be allowed to take on materials at ports inside the US due to their lack of US construction, ownership, or operations.

The offshore wind lease area near Kitty Hawk, North Carolina, was awarded to Avangrid Renewables, LLC on November 1, 2017. According to Addendum "B" of that lease agreement (OCS-A 0508), the Site Assessment Term will end in November 2023, after which a 25-year Operations Term will commence. Currently, 500 MW is expected to be operational in 2025, but this timeline will likely depend on the availability of ships for construction. Blue Energy, an indirect subsidiary of Dominion Energy, has contracted for the construction of a Jones Act compliant ship named Charybdis that is expected to be sea-ready by late 2023. However, this ship may be in high demand as BOEM has issued leases for over 5,000 MW of offshore wind in the Northeast that are targeting commercial operations between 2023 and 2025. This question of ship availability and lack of additional Jones Act compliant ships represents significant risk to development of offshore wind for North Carolina. The recent Carolina Long Bay auction resulted in the execution of leases to Total Energies Renewables USA, LLC[44] and Duke Energy Renewables Wind, LLC.[45] However, the availability of offshore wind capacity in this lease area is uncertain, and Duke has stated that it is not feasible for offshore wind projects in that area to be online by 2030.[46] In addition, no routing path has been provided to date and as such there is some uncertainty as to the mileage of transmission necessary to interconnect offshore wind resources in the Carolina Long Bay lease area.

Another engineering risk is that offshore wind in the Northeast does not face as great a risk for severe hurricanes as North Carolina, which has experienced three category 4 hurricanes in the previous 150 years according to NOAA. If the

[44] *See* Executed lease OSC-A 0545.

[45] *See* Executed lease OSC-A 0546.

[46] *See* Proposed Carbon Plan Appendix J at 6.

engineering risks can be mitigated and regulatory processes can be streamlined, offshore wind may be feasible for providing power to North Carolina on the timelines envisioned in the Proposed Carbon Plan. However, the lack of Jones Act Compliant ships is currently the greatest risk to commercial offshore wind operations for the lease areas off North Carolina's coasts.

New Nuclear

All portfolios add SMRs in either 2032 or 2033, with all portfolios reaching a cumulative total of 1,140 MW of SMR capacity by 2036, with incremental additions occurring later in the planning horizon. Notably, Duke used the GE Hitachi (GEH) BWRX-300 SMR unit in its model.[47] This SMR is currently in the pre-application step with the NRC. Other SMR designs, such as those submitted to the NRC by NuScale Power, LLC (NuScale), were not modeled. GEH has partnered with Ontario Power Generation and expects to deploy its first BWRX-300 reactor as early as 2028.[48] NuScale has partnered with the Utah Associated Municipal Power Systems (among others), and estimates deployment of its first reactor in 2029, three years later than original estimates of 2026.[49] Even if the

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[47] *See* NRC Docket 99900003.

[48] *See* GEH website, accessible at https://nuclear.gepower.com/build-a-plant/products/nuclear-power-plants-overview/bwrx-300 (last accessed July 1, 2022).

[49] *See* NuScale's Fall 2018 newsletter, accessible at https://www.nuscalepower.com/newsletter/nucleus-fall-2018/uamps-update (last accessed July 1, 2022).

most recent manufacturer estimates are correct, a significant amount of development must first occur, much of which is outside of Duke's control (such as fuel supply chain, NRC approvals, and construction activity), in order to have Duke's SMRs online by 2032 or 2033.

All portfolios also add their first advanced reactor with integrated thermal storage in 2037,[50] and continue to add advanced reactors every year until 2047, when each portfolio calls for 4,830 MW of advanced reactors. TerraPower, the manufacturer of the advanced reactor used in Duke's Proposed Carbon Plan, has partnered with PacifiCorp to site its first reactor at a retiring coal plant in Kemmerer, Wyoming. This reactor is estimated to be online in 2028.[51]

While the Public Staff agrees that SMRs and advanced reactors are likely necessary to achieve compliance with Section 110.9's CO_2 reduction goals, particularly if hydrogen availability falls short of Duke forecasts, the pace and timing of these additions are very aggressive and represent significant portfolio risk. Given that the NRC has not given approval to any SMR or advanced reactor design at this time, the timelines are highly speculative. The Public Staff recommends that Duke perform required research and near-term development

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[50] In its Proposed Carbon Plan, Duke assumes the advanced reactors will be the TerraPower and GE Hitachi Natrium reactor, NRC Docket 99902087.

[51] *See* December 13, 2021 Natrium press release, accessible at https://www.terrapower.com/natrium-reactor-reality-2021/ (last accessed July 1, 2022).

and planning activities for SMRs to be sited in its territories by the planned in-service dates as requested in its Petition. Advanced reactors appear to be necessary for compliance with the 2050 carbon reduction target, but near-term development activities on Duke's part related to advanced reactors may not be required at this time. Duke should report on the progress of new nuclear in its 2024 Carbon Plan filing.

New Natural Gas Plants

As discussed above and in the Commodities section of these comments, Duke's Proposed Carbon Plan relies on hydrogen blending with natural gas to achieve its carbon reduction targets. Duke's current assumption is that hydrogen blending will not begin until 2035, after it achieves the interim 70% target. However, Duke plans to expand its natural gas fleet significantly in all portfolios, as shown by Table 9 below. Much of the natural gas additions in later years represent CTs and CCs capable of running on 100% hydrogen. Duke's decision to build these natural gas units over the next five to ten years is justified largely by the assumed hydrogen blending.[52]

The Public Staff is concerned that if hydrogen is not available at the volume and price Duke estimates, or not available at all, the natural gas plants built in

[52] Duke's Proposed Carbon Plan identifies a need for the first new CTs to be added between 2027 (P1) and 2030 (P2 through P4), and the first new CCs to be added in 2028 (all portfolios).

anticipation of hydrogen blending may end up being stranded assets as Duke proceeds toward meeting its 2050 compliance target. As part of a strategy to address this risk, the Public Staff recommends that hydrogen blending be removed from the model runs entirely as part of its proposed P5 filing. If the model still economically selects natural gas plants, even without access to hydrogen, it would provide some assurance as to the risk of stranded natural gas assets.

Table 8: Hydrogen Blending and New Natural Gas Capacity (MW)

Fuel Blend	2030	2035	2040	2045	2050
H2 % By Volume	0%	10%	15%	15%	100%
Portfolio	2030	2035	2040	2045	2050
P1	3,559	3,559	4,686	5,438	9,196
P2	3,559	3,559	4,686	5,438	8,820
P3	2,807	3,934	5,062	5,813	9,947
P4	3,183	3,559	4,686	5,813	9,196
Alternative Portfolio	2030	2035	2040	2045	2050
P1A	3,067	3,067	4,194	4,570	8,704
P2A	1,939	2,315	4,194	4,946	8,328
P3A	1,563	3,067	4,946	5,697	11,710
P4A	1,939	3,818	5,321	6,073	11,710

The Companies' Rate Disparity

The last, but far from least, risk identified in Table 8 above is the amount of DEC's annual energy demand that is served by DEP resources by 2035. The rate disparity between DEC and DEP has grown in recent years and continues to grow. The typical residential bill for a customer in North Carolina is approximately $105 in DEC and $115 in DEP,[53] a $10 disparity. By 2030, this disparity is expected to increase under the Proposed Carbon Plan. The typical residential bill, averaged across all primary portfolios, is projected to be $115 in DEC and $141 in DEP, a $26 disparity.

The increasing amount of DEC load that is served by DEP generation resources reflects generation and transmission assets that are built in DEP's territory that will be used to serve DEC's load. Absent a change to how rate-based costs are allocated, this increase in DEC load served by DEP will exacerbate the existing rate disparity. The Public Staff has identified this issue in several dockets, most recently within the context of the 2022 Solar Procurement.[54] The goal of more closely aligning the rates of DEC and DEP is not a specific objective of the Carbon Plan, but the Commission should take steps to prevent its Carbon Plan from worsening the existing rate disparity. In fact, the Commission has directed both Duke and the Public Staff to "get to work on a solution to this significant issue."[55] A solution begins with equitable allocation of Carbon Plan costs in the interim and

[53] The Public Staff's calculations of DEP's current residential rate schedule reveals that DEP's current typical residential bill is actually $124. However, the $115 starting value is derived from DEP's bill impact analysis and is used here to illustrate the expected change to DEP customer bills.

[54] *See* Initial Comments of the Public Staff, n.5 at 7, filed in Docket Nos. E-2, Sub 1297 and E-7, Sub 1268.

[55] *See* Order Authorizing a Competitive Procurement of Solar Resources Pursuant to House Bill 951 and Establishing Further Procedures, Docket Nos. E-2, Sub 1297 and E-7, Sub 1268, at 5 (May 26, 2022).

should end with a full merger of the utilities. However, to date, Duke has not proposed any concrete cost allocation mechanism to address this rate disparity. It is the Public Staff's position that Duke should propose a reasonable and equitable cost allocation mechanism to fairly allocate the costs of HB 951 compliance while it pursues a full merger of the utilities, which goes beyond the planned combination of balancing areas.

Other Risk Factors

Another concern of the Public Staff is the 1,680 MW Bad Creek powerhouse expansion (Bad Creek II), which Duke assumes to be in service by 2032 in all portfolios. Duke projects that construction would have to commence by 2027 in order to meet this in-service date and estimates a cost of approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. While long duration storage such as Bad Creek II could be a useful tool for full decarbonization,[56] the execution timeline envisioned in the Proposed Carbon Plan may not be realistic. The original construction of Bad Creek took approximately ten years, and while a second powerhouse would require less substantial construction activities than the first, even a five-year construction

[56] For example, see the United States Department of Energy's Long Duration Storage Shot, accessible at https://www.energy.gov/eere/long-duration-storage-shot (last accessed June 29, 2022).

timeline for Bad Creek II is significant given the carbon reduction timelines in Section 110.9.

Given the complexities associated with expansions and scale of Bad Creek II, the Public Staff supports further project development in order to determine more refined project scope, risk evaluation, and cost estimates. The Public Staff requests that Duke provide a general timeline of the overall project along with expected project spend on a quarterly basis from 2023 to the project in-service date (e.g., a quarterly Gantt Chart or equivalent).

The Public Staff has also reviewed the reliability of each portfolio. Duke's metrics of net load ramp rate[57] and average number of CC starts per year can help show the effect each portfolio has on system reliability. A higher net load ramp rate makes it more difficult for dispatchable resources to meet demand, particularly if energy storage resources are not sufficiently charged. Increasing penetration of intermittent resources can contribute to higher ramp rates. Table 10 below presents these results and the estimated reserve margin at peak load for each portfolio in years 2030 and 2035.

P1 represents the most significant net load ramp, which is largely a result of the significant quantities of additional solar, which can create steep net load

[57] The net load ramp rate refers to the ramp rate of load that must be met after solar generation is subtracted from the gross load.

ramping events in the morning (as solar is coming online) and in the evening (as solar is coming offline). These severe net load ramp rates require dispatchable resources, such as natural gas CTs, CCs, and energy storage, to respond quickly in order to meet load. The Public Staff notes that the way S+S resources are modeled may contribute to this net load ramp rate, as their output profiles are fixed and not able to respond to conditions within the model.

Table 9: Reliability Metrics

Portfolio	P1		P2		P3		P4	
Year	2030	2035	2030	2035	2030	2035	2030	2035
95th Percentile Expected Net Load Ramp (MW/hr)	6,604	10,803	5,341	8,621	5,506	8,656	5,296	7,922
Average CC Starts per Year	53	99	35	77	34	75	29	67
DEP Winter Reserve Margin	25%	28%	25%	25%	21%	19%	20%	17%
DEC Winter Reserve Margin	35%	39%	28%	30%	28%	30%	28%	30%

Duke also describes other efforts to monitor the reliability of the grid in each portfolio. In addition to modeling a 17% reserve margin, Duke has calculated the ELCC for intermittent resources (wind, solar, and S+S) to account for their contribution to peak demand. The ELCC for each resource declines as more of that resource is added to the system, which reflects the declining marginal utility of intermittent resources. For example, once 5,000 MW of solar has been added to DEC's system, the next 100 MW will only contribute one MW, or one percent of nameplate capacity, to the reserve margin calculation. The Public Staff also notes that the reserve margin associated with each portfolio remains generally above the current target of 17% in 2030 and 2035, indicating sufficient capacity resources to meet demand even when the intermittent nature of solar, wind, and energy storage is taken into account.

Duke also modeled portfolios using the SERVM model, which can estimate the Loss of Load Expectation (LOLE) for each portfolio.[58] The SERVM model evaluated portfolios in 2030 and 2035 to ensure the LOLE meets industry reliability standards of approximately 0.1 events per year. Duke found that all four portfolios satisfied the LOLE criteria without needing to add additional CTs. This may be due to Duke's replacement of 35% of battery storage capacity with CTs, which is performed in the prior modeling step and likely increases system reliability.[59] While the increase in intermittent renewables and battery storage resources will present novel challenges to Duke's system operators, the Public Staff believes that sufficient capacity and energy resources are available in each portfolio to reliably satisfy customer demand.

[58] This model is also used to calculate each resource's ELCC and the target reserve margin.

[59] *See* Duke's discussion of Battery-CT Optimization Modeling in Proposed Carbon Plan Appendix E at 59.

Transmission System

Any path to achieve the carbon reduction goals contained in Section 110.9 must consider transmission, transmission planning, and transmission costs. The Public Staff presents a summary of the improvements in transmission planning made from the previous IRP, potential transmission tariffs, future transmission planning, and proactive transmission planning.

Transmission Cost Adders for Resource Selection

In previous IRP modeling, Duke added the transmission cost after a model selected a generation resource (post process). While this approach identifies the total or expected cost for implementation of a transmission plan, Duke's approach prevented the capacity expansion model from determining if the combined cost of a resource and its transmission was the true least cost option compared to other technologies, an issue raised by the Public Staff's comments in the 2020 IRP proceeding.[60] Duke's Proposed Carbon Plan remedies this issue by including estimated transmission costs in the capacity expansion model runs that evaluate the total cost of potential resources inclusive of transmission upgrades.

[60] *See* Initial Comments of the Public Staff, filed February 26, 2021, in Docket No. E-100, Sub 165, at 145.

In its Proposed Carbon Plan, Duke includes transmission cost adders for new generation regardless of technology type. The proposed transmission cost adders are based on historic interconnection costs of similar technologies or best estimates of expected interconnection costs as proxies. Examples of these proxies are: (1) solar transmission upgrade costs from the recent 2021 Transition Cluster Study results, and (2) estimated transmission upgrade costs for different levels of nameplate capacity of offshore wind. Overall, the Public Staff does not take issue with Duke's proposed transmission cost adders and the modeling methodology utilized in its Proposed Carbon Plan. The Public Staff notes that the transmission cost adders used for solar resources were based on the most recent Transitional Cluster Study, and are the same in both DEC and DEP.

The Public Staff has focused on the significant rate disparities between DEC and DEP elsewhere in these comments but notes that while DEC and DEP have utilized different transmission cost adders in the past based on historic data, it is uncertain whether these differences in historic transmission cost adders will remain as the electrical system undergoes transformation and the Commission's Carbon Plan is implemented. Duke's transmission cost adders should reflect variances between DEC and DEP territories in future Carbon Plans.

Because the Commission's approval of a Carbon Plan is not an approval of a Certificate of Environmental Compatibility and Public Convenience and

Necessity (CECPCN) for any transmission line, the Public Staff will review transmission study results and other relevant information in comparison to the assumptions used in the Commission's Carbon Plan when reviewing future CECPCN applications. This review will ensure that the proposed interconnecting resource conforms to the optimal portfolio and portfolio assumptions. If the resource and transmission details in the CECPCN application are inconsistent with those utilized in the approved Carbon Plan in scope, timing, risk, costs, or otherwise, the Public Staff may request that Duke re-run capacity expansion and production cost models to alleviate any concerns of the Public Staff and the Commission regarding regulatory compliance and reliability.

The Public Staff recommends that Duke, in future Carbon Plan filings: (1) update the transmission cost adders based on the most recent interconnection cluster study in combination with engineering judgment; and (2) provide support showing how it derived the transmission cost adders.

<u>Transmission Tariff and Modeling</u>

The EnCompass model used the three Duke Balancing Areas (BAs)[61] to represent the current transmission system. The model further simulated connections (interties) between each of the BAs, with maximum seasonal capacity

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

limits, to simulate an aggregated transmission system. Even though the Proposed Carbon Plan models merged the DEC and DEP BAs, these 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. The Public Staff does not currently take issue with how Duke has modeled these BAs and the interties.

The EnCompass model simulates power flows across each tie point on an hourly basis, and the maximum power flows align with current transmission limitations. The EnCompass model allows certain technical and economic characteristics such as losses and transfer costs, similar to Duke's OATT, to be applied to both forward and reverse power flows across these interties. The Proposed Carbon Plan includes a proxy for expected system losses based on the Companies' best judgment, which the Public Staff supports. However, no tariffed transfer cost was applied to power flows between each BA in the model.

Utilization of the transfer costs in Duke's OATT would force the model to evaluate whether it is more cost-effective to build generation in one BA and transport the energy to another BA, versus building the generation in the same BA as the load, even if the generation itself may cost more to build but avoids the transmission cost penalty. A second benefit to inclusion of tariffed transmission costs for regional transfers is the revenue stream realized by the generating BA, which would reduce the annual PVRR and estimated bill impacts.[62]

The Public Staff recommends that for modeling purposes, the Commission require Duke to create a transmission tariff within EnCompass to match, at a minimum, the current FERC-approved utility specific non-Firm Service annual $/kWh tariff as found in the publicly available OATT for each utility, and to make this update in the P5 model run requested by the Public Staff, as well as future Carbon Plan filings. Public Staff modeling suggests that this tariff would be material to resource selection. The transmission tariff should have a time series change for each year based on Duke's estimates of ongoing transmission investment and should include a proxy for inflation. Table 11 below proposes first-year non-firm service transmission tariff adders for EnCompass.[63]

Table 10: Proposed Transmission Tariffs

	DEC $/MWh	DEP $/MWh
On-Peak Hours	$ 3.86	$ 5.58
Off-Peak Hours	$ 1.84	$ 2.66

[62] The current JDA includes a similar provision for benefit sharing.

[63] The listed values can be found in each of DEC's and DEP's publicly available OASIS websites, within the Transmission Rates sub folder. Some of the row identification text for $/kW and $/kWh is different between and DEC and DEP even though they are performing the same math function. The DEC row identification information is labeled as $/kW and it should be $/kWh. If this observation is in error, Duke should provide the appropriate non-firm Service transmission adders.

The Public Staff expects that these adders will require further discussion with Duke in the development of future Carbon Plans, as the tariff would likely need to change over time. As transmission costs increase, the OATT will also increase. The Public Staff expects that DEP's transmission costs will likely grow at a faster rate than DEC's, given the siting cost advantages carbon free resources currently have in DEP territory.

Future Transmission

Successful implementation of Section 110.9 will require substantial changes to the current method of transmission planning. As such, the Public Staff first recommends extending long-term transmission planning to 20 years.[64] The first 20-year long-term transmission plan should be completed prior to the 2024 Carbon Plan proceeding and should be based on the Commission's 2022 Carbon Plan. The significant volume of generation asset retirements and additions creates the need for identification of longer-term and more comprehensive transmission solutions. While a long-term transmission plan is not a substitute for formal Commission approval to construct a new line or acceptance of an individual transmission project, it will help to identify long-term needs for Duke and other transmission users, as well as the risk factors associated with these projects. The

[64] The California Independent System Operator and the Electric Reliability Council of Texas have 20-year transmission planning processes.

long-term plan should also identify the potential for proactive upgrades as well as all upgrades required to maintain NERC compliance.

The Public Staff's second recommendation with respect to future transmission needs is for Duke to continue to provide updated locational guidance maps in future DISIS and procurement solicitations. The locational guidance should reflect known upgrades, inclusive of proactive upgrades that Duke plans to build. The locational guidance should reflect known upgrades, inclusive of proactive upgrades that Duke plans to build.

In addition, in future Carbon Plan filings, Duke should clearly identify and justify any proactive transmission upgrades and provide the lead times necessary to construct them. The continued identification of future transmission upgrades and robust discussion and analysis will help stakeholders understand how the current electrical system (generation and transmission) will need to be upgraded in order to maintain its safety and reliability.

<u>Proactive Transmission Planning</u>

Expansion of the transmission system will be a multi-year process that will challenge execution timelines necessary to comply with Section 110.9. On June 27, 2022, Duke made a presentation to the North Carolina Transmission Planning Collaborative's (NCTPC) Transmission Advisory Group and proposed a mid-year update to the 2021 Plan that includes in the baseline assumptions a list of transmission projects in both DEC and DEP territories, none of which were included or even discussed in the original 2021 Plan. These updated projects included high-level, preliminary cost estimates of approximately $560M ($241 million of upgrades in DEC and $319 million in DEP). These upgrades are included in Proposed Carbon Plan Appendix P.

The timelines imposed by Section 110.9 have created a need to re-evaluate current transmission planning processes given the risks in each Proposed Carbon Plan portfolio. The Public Staff has considered both “least cost” and “least regrets” transmission planning,[65] and, more specifically, how proactive transmission planning can assist in the development of a least regrets plan. All four portfolios share similarities in resource selection, particularly in the early years, with differences emerging later only in the timing and quantity of each resource. The Public Staff expects further similarities in the results of P5, resulting in a truly least regrets approach to future generation selection and the most likely transmission upgrades.

[65] The Public Staff is referring to “least cost” as least *reasonable* cost and not the absolute lowest cost transmission expansion plan. Given uncertainty as to where generators may choose to interconnect, power flow complexities, and uncertain timing of future resource additions, it is unlikely that absolute lowest cost can be achieved. A “least regrets” approach attempts to execute on a reasonable plan that has a high likelihood of being a least cost plan but would still be considered prudent even if certain assumptions turn out to be incorrect.

The question is whether to build proactive upgrades in anticipation of future interconnections or reactive upgrades in response to interconnection requests. Regardless of which near-term actions the Commission approves, the transmission interval data from the Proposed Carbon Plan demonstrate reliance on increased power flows across the interties between DEC and DEP, with transfers reaching maximum limits with increasing frequency as time passes. At this time, the transfer limit is assumed static over the planning horizon, with no increases to capacity transfer capability. The Public Staff is concerned that increasing instances of maximum transfers will require additional transmission evaluations or new generation capacity in specific BAs, perhaps uneconomically, in order to minimize the risk of over-reliance on transmission interties. As an alternative to forcing generation into specific BAs, EnCompass has the ability to optimize the expansion of the interties between DEC and DEP if accurate costs for such projects are input into the model. The model can then choose to upgrade the intertie, rather than uneconomically build generation in the same BA as the load.[66]

Each portfolio anticipates an approximate doubling of power flows across the transmission interties from DEP to DEC from 2022 to 2030. Table 12 below illustrates an example from Portfolio 1 and its respective increase in total power

[66] In its 2020 IRP, Duke estimated it would cost approximately $4 billion to $5 billion to increase import capacity by 5,000 MW. *See* DEP 2020 IRP at 60 and DEC 2020 IRP at 58.

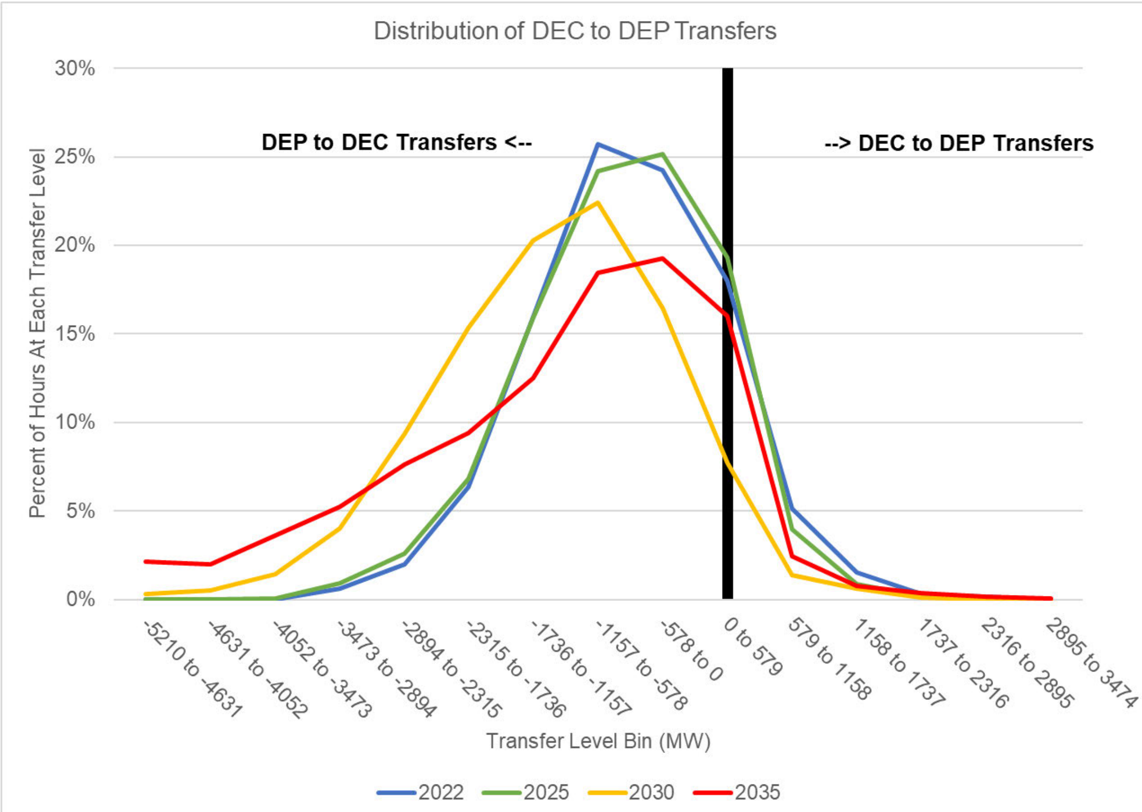
flow from one utility to another as well as the amount of energy being produced in one utility above its own load requirement.

Table 11: DEC to DEP Power Flows, P1

P1				
DEC to DEP Power Flows (negative value is power flow from DEP to DEC)				
Year	2022	2025	2030	2035
Total Annual Power Flows DEC to DEP (MWh)	(5,358,007)	(5,750,105)	(11,125,745)	(10,621,229)
Annual Percentage of Power Flows DEP to DEC in each Year	74.9%	75.7%	90.1%	80.2%
DEC Estimated Load	91,774,392	92,348,958	95,453,647	100,289,431
DEP Estimated Load	63,877,578	64,525,314	65,375,714	68,254,312
Percent of Annual DEP to DEC Transfers Compared to DEP Nomial Load	8.4%	8.9%	17.0%	15.6%

Figure 18 below shows the evolution of power flows from 2022 to 2035 in P1 of the Proposed Carbon Plan. The shift over time to the left indicates that there is an increase in the size and number of transfers of energy from DEP to DEC, as well as in the number of hours in which Duke reaches the maximum transfer limit in the model. In 2022, the median transfer rate is 592 MW from DEP to DEC; by 2035, the median transfer rate is 905 MW from DEP to DEC. This trend occurs in all portfolios, indicating increasing power flows across the interties and the need to economically dispatch DEC and DEP assets for the benefit of both utilities. Duke also assumes in the model that the transfer intertie capability will never increase in capacity; if the intertie capacity was increased, this trend of increasing power flows could continue even further.

Figure 18: Distribution of Power Flows Between DEC and DEP in P1



The Public Staff identified two main risk factors with future transmission construction: (1) insufficient time to build large scale transmission upgrades to allow economically selected generation; and (2) wasted proactive transmission assets. Duke's currently planned transmission upgrades and their timelines show an increasing risk of not meeting goals set forth in Section 110.9 by 2030. The second risk factor, wasted proactive transmission assets, can be further divided into two categories: (1) building transmission that is either not utilized or under-utilized; and (2) building transmission only to have it replaced by future upgrades in the first 10 to 15 years of the original asset's 40- to 60-year asset life. To the extent that proactive upgrade planning can address these two risk factors, proactive upgrades should begin as soon as practicable.

Another factor to consider is the allocation of Carbon Plan costs between DEC and DEP. The Public Staff recommends that a portion of the costs of DEP's required transmission assets be allocated to DEC proportional to DEC's reliance on those assets in order to meet its allocable share of CO_2 reduction requirements. Cost allocation for DEC's use of DEP's transmission assets should be part of any proposal for future proactive transmission upgrades, to the extent that those upgrades provide benefit to DEC, until DEC and DEP can merge into a single utility.

The Public Staff has reviewed Duke's proposed proactive transmission upgrades and studied the potential risks. Given the amount of time needed to build Duke's proposed transmission upgrades, the Public Staff supports proactive transmission upgrades but has concerns as described below.

The past few years of increasing interconnection requests and the resulting impacts on the transmission system have revealed that large scale transmission projects require significant time to build and the need to coordinate associated line outages to ensure system reliability. These outages can also affect other generation interconnection customers. Duke and the Public Staff have met to discuss transmission impacts and the required lead times for planning and construction, inclusive of the NCTPC process. Duke should move from a purely reactive transmission upgrade approach, where it constructs transmission only after a generator has requested interconnection, to a planning process that also considers proactive upgrades in anticipation of future generation required by the Carbon Plan adopted by the Commission.

Determining which projects should be included in proactive upgrades and which should be excluded is difficult. Using assumptions from past interconnection requests might not accurately represent the needs of future interconnection requests given the potential for speculative or non-commercially viable projects and the unique nature of each interconnection request. The Public Staff has considered the challenges of building particular resources in DEC as compared to DEP based on developer feedback on land parcel sizes, land topography, circuit topology, unit retirements, solar irradiance, and wind energy potential and injection studies, but still needs more information from Duke[67] before recommending a plan that identifies specific upgrades.

[67] The Public Staff will need Duke to provide, at a minimum: (1) the best estimation of which generator projects are commercially viable; (2) an estimation of risks for each upgrade to include construction time, land and right of way acquisition, and ability for additional generation; (3) a description of secondary benefits (e.g., reduced system losses, improvements in system dispatch, less cycling of existing resources, etc.); (4) assurance that the proposed upgrades can accommodate the interconnecting generation; and (5) assurance that the generation aligns with the Commission's Carbon Plan and will not immediately trigger larger upgrades.

In conclusion, it is reasonable for Duke to pursue proactive transmission upgrades. Duke and the Public Staff are still discussing the metrics necessary to evaluate which proactive upgrades would most efficiently and effectively alleviate the red zone constraints and provide the amount of transmission capacity necessary to interconnect the amount of solar capacity that the parties anticipate will be required to meet Section 110.9. Duke has informed the Public Staff that it is developing a study that will be the first step in this process but does not believe it will be ready in time to provide an overview in its direct testimony. The Public Staff therefore recommends that Duke file supplemental testimony in this docket explaining the findings of this study to allow proper consideration by the Commission in its preparation of its Carbon Plan.

The majority of additional proactive transmission upgrade planning can take place at the NCTPC throughout the fall and early winter and be approved by the Commission for inclusion in the baseline for the 2023 procurement process. This process should also allow project developers to start evaluating and preparing for competitive bidding in these areas, resulting in lower costs for ratepayers. Further modifications and review of the proactive upgrade analysis will occur in future Carbon Plans, but the proactive upgrades planned in 2022 will be the least regrets upgrades. Reasonableness and prudency will be reviewed in a general rate case.

Lastly, the Public Staff has concerns regarding the Companies proposing recovery for any of the proactive transmission projects identified in the plan as part of a MYRP filing in the near future given the issues surrounding the appropriate allocation of transmission costs between DEC and DEP systems, as well as the ongoing process of determining the transmission projects needed. Therefore, the Public Staff requests that the Commission delay consideration of cost recovery of any proactive transmission projects in upcoming MYRP filings until such issues have been resolved. The proactive upgrades planned in 2022 are anticipated to be completed from 2026 to 2028. Delaying consideration of cost recovery would allow the Companies more time to make progress toward a full merger of the utilities, while alleviating the cost allocation issues presented above.

The Public Staff's Modeling Results and Evaluation

As described earlier in these comments, the Public Staff recommends several specific changes to the Carbon Plan modeling for incorporation into a new portfolio, P5, that Duke should submit as a supplemental filing prior to the Commission's review of the near-term development activities outlined in Duke's Petition. To the extent that the near-term activities identified by Duke are consistent with the results from P5, the Commission should approve such activities. The following sections detail some of the specific findings of the Public Staff's investigation and provide technical support for related recommendations.

Belews Creek

Belews Creek Steam Station (Units 1 and 2) was recently converted to dual fuel operation (DFO), meaning that it has the ability to burn a combination of natural gas and coal. The DFO conversion allows both units to operate at 50% of their respective nameplate ratings using natural gas.[68] Given the current state of the coal mining and transportation sectors, once Duke starts to retire other coal generation units, the Companies may have difficulty obtaining coal as a reliable and cost-effective fuel. For purposes of modeling, the Public Staff does not take issue with forcing Belews Creek to run on natural gas to the extent that Duke anticipates that coal fuel sourcing will become problematic. However, the Public Staff takes issue with Duke forcing the retirement of all Belews Creek units in 2035, rather than allowing these units to run on natural gas and retire at the end of 2037 in alignment with its most recent depreciation study. The Public Staff is concerned that the decision to retire the Belews Creek units in 2035 was based on an arbitrary target set by Duke Energy Corporation to cease coal generation by 2035,[69] and not on economics.

[68] Belews Creek Steam Station Units 1 and 2 is a mid-1970's vintage supercritical coal plant in DEC's territory with a total nameplate rating of ~2,200 MW. The DFO conversion allows for approximately 1,100 MW of natural gas generation.

[69] "Belews Creek Station retirement is accelerated from its Probable Depreciable Life to 2036 in the Initial Coal Unit Operations Runs to reflect Duke Energy's target to close all coal-fired plants by 2035 and address fuel security risks." *See* Proposed Carbon Plan Appendix E, Table E-45, note 2, at 46.

This issue is two-fold. First, the economic retirement evaluation did not appear to consider that Belews Creek could solely operate on natural gas at 50% capacity, and therefore it is unknown if forcing the unit to retire two years early is reasonable or part of the least cost solution. Second, early retirement of a ~2,200 MW generating station will trigger or accelerate the need for replacement generation capacity, specifically the onshore wind, SMRs, and advanced reactors selected in each DEC portfolio between 2035 and 2037, and the CTs selected in P3 and P4 in 2035.

The Public Staff therefore makes the following recommendations: (1) for the 2022 Carbon Plan, Duke should remove the forced retirement date and allow Belews Creek to run to its depreciation study end-of-life year of 2037, utilizing its DFO capabilities if necessary; (2) in future Carbon Plans, Duke should take into account each coal plant's DFO capabilities when performing its endogenous coal retirement analysis; and (3) in future Carbon Plans, Duke should complete a transmission evaluation and consider the generation retirement dates given potential transmission additions and their respective risks, lead times, and costs.

Both Duke's forced retirement date and the depreciation study end-of-life year for the DFO units fall beyond the interim carbon reduction goal year of 2030, but remodeling this constraint would provide more certainty that Duke is selecting the most economical generation resources prior to 2030 and confirm that the selected generation is likely to be least cost. While the Public Staff recommends items 2 and 3 above for future Carbon Plans given retirement timing considerations, the Public Staff is not opposed to Duke completing this analysis in the current proceeding, if Duke believes it has sufficient time to perform and validate such an analysis.

Solar Plus Storage Modeling

S+S is a selectable resource in the Proposed Carbon Plan, with only two available configurations: (1) a 75 MW AC solar photovoltaic (PV) facility co-located with a DC-coupled 40 MW / 80 MWh battery; and (2) a 75 MW AC solar PV facility co-located with a DC-coupled 20 MW / 80 MWh battery. In both configurations, the solar facility has single-axis tracking with bi-facial panels, similar to the standalone solar also modeled in the Proposed Carbon Plan, except with a higher inverter loading ratio. In addition, Duke assumed the storage to be DC-coupled and only chargeable from the coupled solar resource. Every portfolio relies heavily on S+S resources, as shown in Table 13 below. Depending on the portfolio, S+S makes up nearly half of all solar nameplate capacity in the Proposed Carbon Plan. As such, it is a critical resource to both the interim compliance target and the 2050 compliance target.

Table 12: Solar and Storage in Each Portfolio

Portfolio	2030		2035		2040	
	Total MW	% of All Solar	Total MW	% of All Solar	Total MW	% of All Solar
P1	9,499	54%	13,849	48%	17,824	47%
P2	4,249	40%	8,824	41%	13,774	45%
P3	4,924	40%	9,049	42%	14,524	45%
P4	4,099	31%	7,549	38%	13,624	46%

However, the Public Staff has concerns with how Duke modeled S+S in EnCompass. New generation capacity in EnCompass is set up with generation *resources* and generation *projects*, with each project linked to a specific resource. EnCompass resources include the technological inputs, such as minimum capacity, capacity factor and output profile (for solar and wind resources), ramping limits, and outage rates. EnCompass projects include financial inputs, such as the capital cost to build, property tax rates, and the maximum number of units that can be built annually and cumulatively.

S+S is unique in that it is actually two resources combined—solar PV and battery storage—with cost savings relative to the standalone resources. In addition, a S+S resource has a higher Effective Load Carrying Capability (ELCC) than standalone solar.[70] Once selected, the model should then be able to dispatch the energy storage component of a S+S resource independently and in response

[70] ELCC is a measure of what percentage of nameplate capacity can be counted toward reserve margin calculations.

to load and generation conditions in any given time period. Depending on whether the battery storage resource is made dependent on the solar PV resource within EnCompass, the battery may be restricted to only charging from the solar PV resource.

The Public Staff discovered during its investigation that Duke did not allow EnCompass to dispatch the storage component of the S+S resource. Instead of modeling each S+S resource as a combination of a solar PV resource and a storage resource, Duke modeled it as a standalone solar PV resource with a predetermined output profile. As such, EnCompass is not allowed to dispatch the energy storage component of a S+S resource.

To illustrate this point, Figure 19 below compares standalone solar and S+S output profiles from EnCompass on a winter and summer day. The standalone solar output profile looks as expected; however, the S+S output profile is the net output of the combined S+S plant, after Duke determined the battery storage charging and discharging behavior using its S+S Dispatch model. This model optimizes battery storage dispatch to maximize revenue, based upon projected 20-year avoided energy and capacity rates, allocated to pricing periods last approved by the Commission in Docket No. E-100, Sub 167.

Figure 19: Standalone Solar and Solar Plus Storage Output Profiles

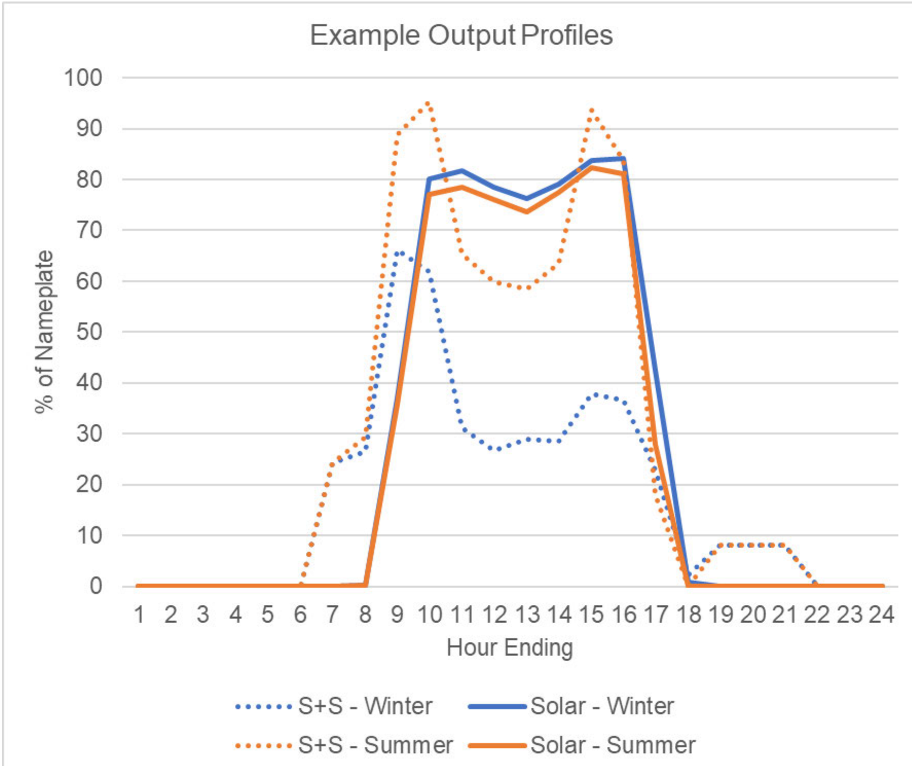


Figure 20 below summarizes the pricing periods for the Companies. The pricing periods were first established in Docket No. E-100, Sub 158 (Sub 158), and were formulated through an analysis of system costs, load, and generation based on Plan A from Duke's 2018 IRPs in Docket No. E-100, Sub 157 (2018 IRP). In developing the S+S output profiles for the Proposed Carbon Plan, Duke used these same pricing periods to optimize the storage component of an S+S resource through 2050. In light of the substantial differences between the Proposed Carbon Plan and the dated 2018 IRP expansion plans used to generate the avoided cost pricing periods, it is unlikely that these pricing periods will continue to accurately reflect the actual marginal system costs so far into the future.[71]

Figure 20: Avoided Cost Pricing Periods

DEC Energy Independent Price Blocks (2021 and 2020)

	Summer Premium Peak			Summer On-Peak			Summer Off-Peak		Winter Premium Peak			Winter On-Peak (AM)			Winter On-Peak (PM)			Winter Off-Peak		Shoulder On-Peak			Shoulder Off-Peak	
Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jun - Sep)	Off												On				Premium				On		Off	
Winter (Dec - Feb)	Off					On	Premium			On	Off							On (PM)					Off	
Shoulder (Remaining)	Off						On				Off						On							Off

DEP Energy Independent Price Blocks (2021 and 2020)

	Summer Premium Peak			Summer On-Peak			Summer Off-Peak		Winter Premium Peak			Winter On-Peak (AM)			Winter On-Peak (PM)			Winter Off-Peak		Shoulder On-Peak			Shoulder Off-Peak	
Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jun - Sep)	Off													On			Premium				On	Off		
Winter (Dec - Feb)	Off				On		Premium			On		Off							On (PM)				Off	
Shoulder (Remaining)	Off					On					Off							On						Off

Duke states that this modeling process for S+S resources reasonably captures the value of S+S, while also acknowledging that as more solar and other resources such as offshore wind and advanced nuclear are added to the system, the hourly marginal prices may begin to shift to different times of day. However, the Companies' systems are changing rapidly, and this factor, combined with the other concerns as outlined above, makes Duke's assumptions regarding S+S unreasonable. In addition to the lack of flexibility modeled for these S+S resources, Duke assumes that all S+S resources will have DC-coupled battery storage and that the storage resource will be unable to charge from the grid. This assumption

[71] The avoided cost pricing periods first approved in Sub 158 were a result of the Agreement and Stipulation of Partial Settlement between Duke and the Public Staff, filed on April 18, 2019. This stipulation created a methodology to update the pricing periods in recognition of the fact that they may need to change over time, as system conditions change.

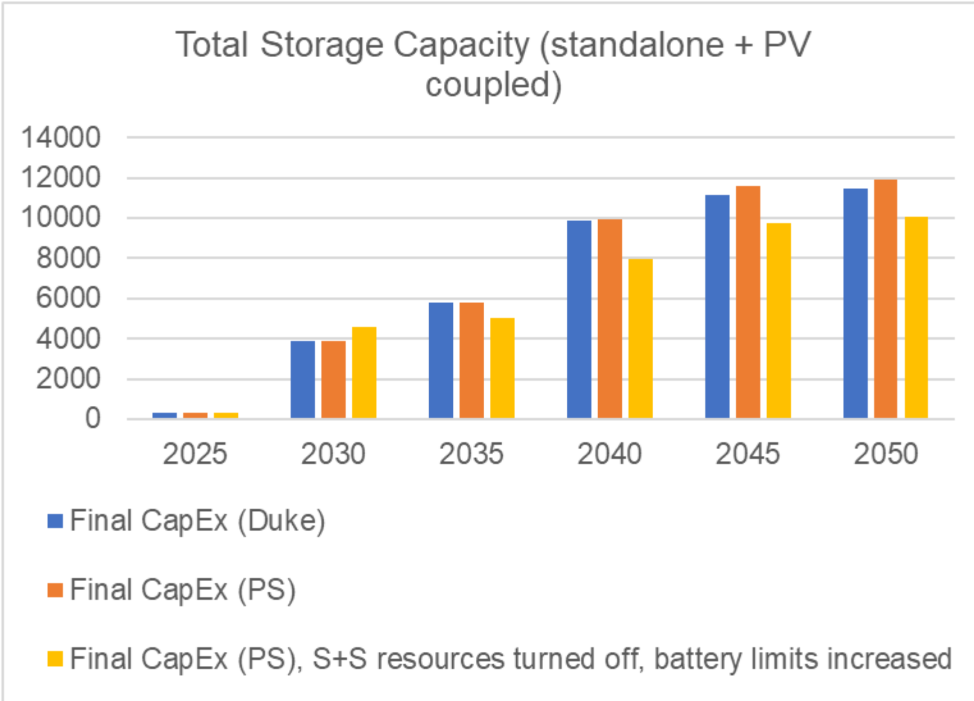
further limits the flexibility of S+S resources in the model and is particularly questionable given that S+S resources can still access some or all of the federal solar PV investment tax credit, so long as at least 75% of the battery's energy input is from the solar PV system.

To test the impact of this modeling choice on the Proposed Carbon Plan portfolios, the Public Staff re-ran the P1 capacity expansion model with all S+S resources turned off and the allowable limit on four-hour battery capacity increased;[72] as a result, the only way to build S+S would be to separately select both battery storage and solar PV resources at a higher total cost. EnCompass still selected significant quantities of standalone energy storage, although slightly less overall storage capacity was needed, particularly in later years, as shown in Figure 21 below.[73] In addition, this change impacted other resource selections, adding an additional 800 MW of offshore wind in 2031 and delaying the required first year of SMR additions from 2032 to 2033.

[72] As discussed later in this section, Duke implemented an arbitrary cap on the total amount of four-hour batteries that could be selected by the model. The Public Staff disagrees with this assumption.

[73] The first bar shows the results of Duke's model runs, while the second two bars show the results of the Public Staff's model runs. This is shown to illustrate how the Public Staff was unable to validate Duke's model runs, as discussed in the Modeling section.

Figure 21: Total Storage Capacity in P1



Put simply, Duke modeled S+S resources too rigidly and has failed to accurately capture the benefits of S+S beyond it having a higher ELCC value than standalone solar. Duke's model dispatched S+S resources to maximize system benefits using avoided cost rates and periods that are based on a capacity expansion plan that is significantly dated and does not align with any of the Proposed Carbon Plan portfolios. Public Staff modeling suggests that the way Duke has modeled S+S may be leading to material impacts on resource selection.

The Public Staff recommends that Duke correct its S+S modeling to allow EnCompass to select and optimally dispatch the energy storage component for all

S+S resources. The Public Staff acknowledges that this change in modeling technique may require substantial modeling effort and will likely increase the model run time. In addition, the Public Staff's modeling suggests that this change might not impact resources selected prior to the interim compliance target. Therefore, while the Public Staff is requesting that this modification be made for its recommended P5 model run to be filed in this proceeding, given the time constraints contained in Section 110.9 for the adoption of a Carbon Plan by December 31, 2022, this change can be delayed until future Carbon Plan filings.

Third Party Solar

Section 110.9 requires that new solar resources selected in the Carbon Plan consist of 55% utility-owned resources and 45% third-party-owned resources through the execution of PPAs.[74] However, in its Proposed Carbon Plan, Duke models all solar resources as utility-owned, stating that it has used a weighted average cost of utility-owned and PPA solar (Blended Solar Cost).[75] Duke found that the Blended Solar Cost was approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** than the Levelized Cost of Energy of Duke-owned facilities, demonstrating material differences in cost between PPA and Duke-owned facilities.

[74] N.C.G.S. § 62-110.9(4).

[75] *See* Proposed Carbon Plan Appendix I at 2.

This treatment of solar resources assumes that all PPA solar procured in the future will be similar to solar PPAs that have been procured in the past: must-take with little to no economic dispatch rights held by the utility. It is likely, however, that future solar PPAs will allow for increasing levels of economic curtailment, with the potential for fixed-price contracts to emerge in future solar procurements.[76] Fixed-price contracts for capacity[77] were discussed as a potential solution for dispatch and curtailment rights during the CPRE Program proceedings in 2019.[78] The 2022 Solar Procurement also calls for 25-year PPA contracts, which would reduce uncertainty regarding post-PPA pricing assumptions. The Southeast Energy Exchange Market is expected to commence operations within the year, which would provide a market by which excess solar could be offloaded, providing additional flexibility to Duke system operators.

As such, third-party PPA solar should be modeled in the Carbon Plan as a different resource type than utility-owned solar, with the ability to dispatch down (within reasonable limits) if necessary, during certain parts of the year. This issue

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[76] Duke has also indicated the need for more time to develop more complex contract structures related to the provision of solar and S+S facilities in its Response to Commission Order Requesting Answers on 2022 Solar Procurement Program Petition, filed on April 29, 2022, in Docket Nos. E-2, Sub 1297 and E-7, Sub 1268.

[77] A fixed-price contract for capacity could be structured to pay for a fixed price per MW-month, rather than per MWh, thus allowing the solar asset to be dispatched in a way that benefits the system. *See* Comments of First Solar, Inc, filed on March 22, 2019 in Docket Nos. E-2, Sub 1159 and E-7, Sub 1156.

[78] *See* the May 23, 2019 Technical Conference transcript, Volume 2, at 106, filed on June 10, 2019 in Docket Nos. E-2, Sub 1159 and E-7, Sub 1156.

was also addressed in Duke's South Carolina IRP proceeding, and the South Carolina Public Service Commission ordered Duke to include third-party PPA resources in its modified 2020 IRP.[79] This modeling change should be incorporated into the P5 model run recommended by the Public Staff and all future Carbon Plan filings.

Battery Installation Limits

In its capacity expansion models, Duke placed limits on the amount of battery storage that could be added over the planning horizon. Specifically, Duke limits the amount of four-hour battery capacity that can be added over the entire planning horizon to 1,500 MW in DEC and 1,800 MW in DEP.[80] Duke has stated that these limits were put in place to reflect the declining ELCC of battery storage.[81] In the final capacity expansion model run for each portfolio, this project limit is

[79] *See* the South Carolina Public Service Commission's Order Requiring Modification to Integrated Resource Plans, South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Duke Energy Carolinas, LLC, and Docket No. 2019-225-E, South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Duke Energy Progress, LLC, Docket Nos. 2019-224-E and 225-E, 2021 S.C. PUC Lexis 219, (June 28, 2021), at 64-70.

[80] Duke also limits six-hour batteries to 3,200 MW and eight-hour batteries to 5,000 MW. However, unlike the limits on four-hour batteries, those limits are not reached in any portfolio.

[81] Generally, as more of a particular solar, wind, or battery storage resource is added, the ELCC value declines. For example, during a two-hour winter peak, the first two-hour battery would have a very high ELCC, as it could discharge through the entire peak; but as more two-hour batteries are added, the apparent peak becomes flatter and longer—it appears three hours long. The next two-hour battery that is installed has a lower ELCC because it can no longer discharge over the duration of the peak.

reached in 2035 (P1) or 2038 (P2 through P4). In later post-processing steps, Duke removes at least 35% of four-hour battery storage capacity and replaces it with CTs, as described in the Proposed Carbon Plan Battery-CT Optimization Step.[82] Table 14 below shows the amount of four-hour battery capacity (in MW) selected optimally by the capacity expansion model with fixed coal retirement dates (Final Cap Ex column) and the amount ultimately included in each portfolio, as represented by the final production cost model runs (Final PC). The difference between the two figures is the amount of battery capacity that was manually removed by Duke.

Table 13: Four-hour Battery Storage Capacity (MW)

BA	Limit	P1		P2		P3		P4	
		Final Cap Ex	Final PC	Final Cap Ex	Final PC	Final Cap Ex	Final PC	Final Cap Ex	Final PC
DEC	1,500	1,500	1,150	1,500	700	1,500	700	1,500	350
DEP	1,800	1,800	1,000	1,800	1,000	1,800	1,000	1,800	1,400

The EnCompass model includes the ability to model declining ELCC for resources such as solar, wind, and battery storage. Duke uses an operational constraint to model declining ELCC for wind and solar resources. No other resource with a declining ELCC is subject to a maximum cumulative capacity

[82] *See* Proposed Carbon Plan Appendix E at 57. This step is completed due to the imperfect representation of the load shape used in capacity expansion models.

constraint in the way that Duke has restricted batteries. This restriction prevents the model from selecting additional four-hour battery storage beyond a defined limit, which is binding in every portfolio; in subsequent modeling steps, this already restricted resource is reduced even further. Ultimately, this may lead to an inflated need for dispatchable resources such as natural gas CTs.

As a result of these findings, the Public Staff recommends that the Commission direct Duke to remove or increase the cumulative limits on four-hour battery storage and include this modification in the P5 model run requested by the Public Staff, as well as in all future Carbon Plan filings.

<u>Demand Side Management Strike Price</u>

Duke models a variety of existing DSM programs in EnCompass as DSM resources with defined maximum nameplate capacity and generation. Most DSM programs have a very low maximum annual capacity factor—**[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**—which reflects the limited nature of these programs. These programs are dispatched based on a "strike price," or the energy price at which DSM is the next most economic resource. When the system marginal price exceeds the strike price, DSM programs are triggered. Most DSM programs utilize the same strike price.

The strike price Duke used for modeling existing DSM programs is likely too high and may therefore distort the economic signals to shave system load from DSM-enrolled customers. This distortion is reflected in the low realized capacity factors for each DSM program, which typically do not exceed 0.5%, far less than the maximum limit set by the model. When DSM programs are underutilized, benefits are lost while many fixed costs remain, which can render the program non-cost-effective.

The Public Staff ran P1 and P4 final production cost models with a revised DSM strike price that was 30% lower in all years. This revised strike price resulted in more DSM activations and significantly higher DSM utilization, and generated production cost savings that exceeded what would be expected from the reduction in the DSM strike price. While the Public Staff is not making any recommendations at this time regarding how DSM is modeled, this issue deserves additional attention in future Carbon Plan filings, and Duke should provide more extensive justification for the DSM strike price used in its models. This justification is particularly necessary as the Companies expect to add significant levels of EE and DSM to their portfolios to meet Section 110.9's carbon reduction goals.

Real Levelized Fixed Charge and Unit Lifetimes

When modeling new generation projects and their associated resources, EnCompass allows for a wide range of input data, including total capital expenditures, authorized rate of return, tax rates, depreciation, allowance for funds used during construction (AFUDC), decommissioning costs, and debt and equity structure. EnCompass uses these inputs to calculate the annual economic carrying charge (ECC) in each year over a project's operable life, and modeling decisions are made to minimize the total system ECC. During its investigation, the Public Staff found that Duke did not utilize EnCompass' built-in system for calculating the ECC. Rather, Duke calculated the ECC--which Duke refers to as the Real Levelized Fixed Charge (RLFC)--for each project using its own financial models. The RLFC rate (%) reflects the proportion of total project costs incurred in each year of the project's operable life. This RLFC rate multiplied by the total project cost is then input into EnCompass as an annual cost. Duke states that this approach has been used in past IRP filings. While this approach may appropriately account for Duke's specific calculation of revenue requirements and RLFC, it is problematic.

Duke's calculation of the RLFC uses each unit's actual expected operable life; however, in EnCompass, Duke uses a modeled life of 60 years for all resources. As seen in Table 15 below, all resources except standalone battery storage and offshore wind have operable lives that are longer than the planning horizon.

Table 14: Operable Lives of Resources

Resource Type	Operable Life Used in RLFC Calculation (years)
Standalone Solar PV	30
Solar Plus Storage (all configurations)	30
Natural Gas CT	35
Natural Gas CC	35
Standalone Battery Storage (all durations)	15
SMR	60
Advanced Nuclear	60
Onshore Wind	30
Offshore Wind	25

The Public Staff raises two issues for Commission consideration related to the RLFC rate. First, the SMR and advanced nuclear RLFC calculation is based on a 60-year life; however, the NRC only provides an initial license term of 40 years. All else equal, the longer the operable life used in the calculation of the RLFC rate, the lower the annual cost will be and the less expensive the project will appear to the model. SMR and advanced nuclear units may be eligible for license renewal at the end of their initial 40-year license, but renewal should not be assumed at this time. The RLFC calculation also does not include relicensing costs, which should be included if a 60-year life is assumed.[83] If the RLFC rate for nuclear resources were modeled with a 40-year life, the annual cost of nuclear

[83] Electric generating SMRs have not been commercially deployed. The Public Staff cannot determine: (1) the degradation rate of SMRs; (2) which elements of the main reactor plant will qualify for a license extension; (3) whether the economics of license extensions would be in the best interest of rate payers; and (4) the possibility of license extension by the NRC. The NRC has not issued guidance on license extension for SMRs.

technologies would be approximately 8.8% higher than the annual costs Duke used in its Proposed Carbon Plan. The Public Staff ran a capacity expansion model for several portfolios with a higher nuclear cost and found that it had minimal impact on nuclear selection and deployment. As such, the Public Staff is not making any recommendations related to nuclear costs at this time. However, Duke's use of the RLFC may be a factor with offshore wind, which Duke modeled with a shorter life than onshore wind. Duke calculated the RLFC for offshore wind based on only a 25-year life, which increases the annual cost by approximately 5.3% relative to a 30-year life.

The second issue is that for resources with operable lives less than the 28-year planning horizon, this approach effectively assumes that once the resource is built, it will be replaced with an identical resource at the end of its operable life. The Public Staff is not convinced that Duke's assumption of identical asset replacement is reasonable. Due to the decline in the ELCC of battery storage as more renewable resources and battery storage are added to the grid, 4-hour battery storage capacity installed over the next few years could eventually be replaced with 6-hour batteries, or perhaps not at all. However, Duke's model does not allow this optimization of battery storage resources. Instead, it assumes that once a 4-hour battery storage facility is interconnected, it will always be a 4-hour battery storage facility, continuously rebuilt every 15 years.

At this time, the Public Staff is uncertain if this replacement assumption has a material impact on the Proposed Carbon Plan portfolios, particularly given other recommendations regarding the use of hydrogen fuel. However, modifying the model to allow more flexibility when replacing battery storage capacity that has reached the end of its useful life will undoubtedly increase model complexity and run times. The Public Staff therefore is recommending that Duke address this specific concern in its 2024 Carbon Plan filing and update the Commission on any efforts to improve battery storage modeling at the end of its useful life.

Natural Gas Plants

Duke's EnCompass model included four selectable natural gas resources: (1) 375 MW J-class Frame CT; (2) 200 MW F-class Frame CT; (3) 1,216 MW 2x1 J-Class CC with duct firing; and (4) 812 MW 2x1 F-Class CC. Duke's four primary portfolios only allowed the selection of (1) and (3), while Duke's four alternative portfolios only allowed (1) and (4). Duke states that its reason for only allowing the smaller CC in the alternative portfolios is to "reflect uncertainty and risk of fuel supply in the alternate gas supply sensitivity."[84] However, the Public Staff believes that all portfolios, even the primary portfolios, have significant uncertainty and fuel

[84] *See* Proposed Carbon Plan Appendix E at 31.

supply risk. Therefore, the Public Staff is recommending that Duke allow the selection of smaller F-Class CCs in its P5 model run.

Duke also prevented the F-class Frame CT from being selected in the EnCompass model, even though the resource and its characteristics are included in the EnCompass datasets provided by Duke. Duke states that it excluded the F-class Frame CTs due to their inability to convert to hydrogen in future years. The Generation Unit Summary and other supporting materials show that J-class Frame and other advanced CTs have advantages over F-class Frame CTs, such as a lower heat rate and slightly higher ramp rates. Given the Public Staff's recommendation that hydrogen be excluded from the P5 model, and the differences between the F- and J-class turbines, P5 should be able to select between the F- and J-class turbines with proper constraints.[85] The Public Staff therefore recommends that in P5, Duke allow the F-class turbines (CCs and CTs) to be an allowable selectable resource.[86] The extent to which P5 selects J-class Frame CTs over F-class Frame CTs will demonstrate the robustness of Duke's Proposed Carbon Plan and determine the likely near-term resources needed.

[85] F-frame and earlier CTs (e.g., D-frame) are peaking assets with an annual capacity factor of approximately 3 to 15 percent. However, advanced class turbines, H and J-Class, can likely operate at a 40% annual capacity factor or higher. Duke should allow the traditional F frame CTs a maximum run time each year to simulate historic operations. Duke would not dispatch a traditional F-frame peaking CT at a 40% annual capacity factor even if the model selected it.

[86] This change should require minimal modeling effort, as the F-class turbine characteristics are already in the EnCompass model.

Finally, the Public Staff reviewed the expected retirement dates of Duke's existing CT fleet, as used in the model. The Public Staff found that many of these existing CTs are modeled with an expected life of longer than 35 years, the normal asset life used for new CC and CT plants. For example, **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[END CONFIDENTIAL]

The actual life of existing units is impacted by many factors that are considered in a detailed depreciation study. However, a review of the Companies' 2018 depreciation studies shows that the estimated retirement dates of these units more closely align with a 35-year life, not the lifetimes used in the Proposed Carbon

Plan and 2020 IRPs.[87] Therefore, the Public Staff recommends that the Commission direct Duke, in its P5 modeling run and future Carbon Plan filings, to utilize the estimated retirement dates for existing CTs from the most recent depreciation study.

Bill Impacts

Table 1 in the Executive Summary of the Proposed Carbon Plan presents the estimated bill impacts resulting from the PVRR analysis of Duke's four portfolios for an average residential usage of 1,000 kWh as projected for 2030 and 2035. Table 1 shows a much larger rate increase for DEP's customers than DEC's customers for all portfolios. While mitigation of this disparity, a primary concern of the Public Staff, extends beyond this proceeding, it is worth noting that the carbon reduction goals of Section 110.9 will likely result in significant rate increases for all of Duke's customers regardless of which path to compliance the Commission chooses.

The revenue requirements for the residential and industrial customer classes for each portfolio "only account for changes captured in the Carbon Plan analysis and do not represent an all-inclusive bill impact analysis as other factors

[87] *See* DEC's 2018 Depreciation Study, filed in Docket No. E-7, Sub 1214, Exhibit 1 to the direct testimony of John Spanos, pages VI-10 through VI-12. *See* DEP's 2018 Depreciation Study, filed in Docket No. E-2, Sub 1219, Exhibit 1 to the direct testimony of John Spanos, pages VI-6 through VI-8.

can also influence a customer's bill.[88] In other words, the bill impacts presented in the Proposed Carbon Plan represent only the incremental changes resulting from the Proposed Carbon Plan itself. Duke's narrow focus on Carbon Plan costs is evident in the data represented in Tables E-75 through E-79. It is difficult to predict how factors not related to the Carbon Plan, such as changes in base rates, riders, or customer behavior in response to new tariffs, would affect customer bills over the next 25 years.

The following information informs Duke's bill analysis: (1) the PVRR impacts associated with the generation system and transmission network upgrade costs; (2) the impacts of UEE, demand response, and IVVC; and (3) the cost of maintaining coal units through their projected lives. Duke used a baseline year of 2023 and incorporated supporting inputs related to depreciation rates, cost of capital and capital structure, cost allocation factors based on the single summer coincident peak methodology from the most recent general rate cases,[89] and various plant and expense escalators to determine the overall system-wide retail revenue requirement and rate impact. Any PVRR changes resulting from the Carbon Plan will impact all DEC and DEP customers, and Public Staff Exhibit 2

[88] *See* Proposed Carbon Plan Appendix E at 82.

[89] Docket Nos. E-2, Sub 1219 and E-7, Sub 1214 for DEP and DEC, respectively.

illustrates the rate impact of the Proposed Carbon Plan on industrial customers under eight different scenarios.

Bill Impact Conclusions and Recommendations

The Public Staff does not take issue with Duke's calculations and the results given in Proposed Carbon Plan Tables E-75 through E-79 for residential bills or the calculations related to the industrial bill impacts that are not part of the Proposed Carbon Plan. The PVRR and bill impacts shown represent only the incremental changes resulting from the Proposed Carbon Plan itself and do not represent an all-inclusive bill impact analysis, such calculations are subject to several assumptions and should be interpreted in relative, rather than absolute terms. With that caveat, the data in the tables and in Public Staff Exhibit 2 provide a reasonable illustration of the differences between the bill impacts of each portfolio.

The uncertainties and assumptions in the Proposed Carbon Plan, however, combined with existing trends, programs, and customer behaviors, exacerbate the risk that Duke's Proposed Carbon Plan does not adequately represent the true nature and cost of electric utility service over the next 25 years. Duke presented several policy and program changes in the Proposed Carbon Plan that it intends to pursue in the coming years, such as its effort to reduce energy use by one percent through its EE portfolio. Another proposal is the broader application of time-varying and interruptible rate designs. However, these policy and program changes are dependent on the actions of customers and will likely have minimal influence on the bill impacts that Duke calculated.

As stated earlier in these comments, the Public Staff is recommending that Duke develop a Portfolio 5 with improved inputs, which should provide a more realistic path for Duke's carbon reduction. After Duke's completion of a Portfolio 5, the Public Staff will review the workpapers supporting the PVRR and bill impact calculations to determine what, if any, changes could provide additional information regarding possible bill impacts, which might be considered in future Carbon Plans. Potential changes include, but are not limited to, cost inputs, energy sales forecasts, escalation rates, EV adoption, EE forecasts, DSM/DR usage, IVVC deployment, the fixed and variable costs of service, and expected customer behaviors.

The Public Staff is also concerned about the rate and bill impact disparity that exists between DEC and DEP. Currently, DEP's rates and average bills are significantly higher than those of DEC. For the average residential bill, DEP's basic residential service cost is 10% greater than DEC ($115 compared to $105 for DEP and DEC, respectively). There is a similar disparity for non-residential bills. In order to lessen this disparity, Duke should merge DEC and DEP and execute this effort over several years to avoid rate shock on customers, particularly DEC customers.

In the interim, the Commission should direct Duke to propose a methodology to equitably allocate Carbon Plan costs between DEC and DEP.

Avoidable Cost of Carbon

In the 2021 avoided cost proceeding, Docket No. E-100, Sub 175, there was debate among various intervenors as to whether the Companies should include a cost of carbon (typically expressed as $/ton) in its production cost modeling used to calculate avoided energy rates, which would reflect the carbon reduction goals of Section 110.9. In that proceeding, the Public Staff took the position that it was too early to determine the appropriate avoidable cost of carbon but recommended that, if any avoidable cost of carbon was determined within the Carbon Plan proceeding, the Commission should direct Duke to use the approved Carbon Plan as the expansion portfolio and include the Commission-approved avoidable cost of carbon in its calculation of avoided energy and capacity rates in the next avoided cost filing.[90]

This determination is important in an avoided cost proceeding given that the cost of carbon would potentially be added to the marginal cost of energy. All the Proposed Carbon Plan portfolios identify a need for large amounts of additional renewable capacity and energy; but adding that renewable energy to the

[90] *See* Initial Comments of the Public Staff, filed on February 24, 2022, in Docket No. E-100, Sub 175, at 8.

production cost modeling will, all else equal, drive down the avoided energy rate,[91] negatively impacting the financial viability of Qualified Facilities.

Section 110.9 did not set an explicit cost of carbon that Duke would be required to pay, unlike other carbon reduction policies such as the cap-and-trade system used in the Regional Greenhouse Gas Initiative. Without an explicit cost of carbon, the amount of benefit, if any, should be attributed to renewable generators that sell their output to the Companies and would largely depend on modeling estimates. The difference between the total cost of carbon abatement and the avoided cost of carbon abatement adds complexity. Generally, the avoided cost of carbon abatement will be the lesser of the two, as it would only include costs that are avoidable through the purchase of power from a renewable generator.

However, the need to determine the appropriate cost of carbon to use in the calculation of administratively determined avoided costs may become moot. In response to a Commission question in the 2022 Solar Procurement Docket, Duke stated that FERC's Public Utility Regulatory Policies Act (PURPA) regulations now "expressly provide that states can implement PURPA's mandatory purchase

[91] In the calculation of avoided energy rates, renewable energy sources are modeled as zero cost resources that are at the bottom of the dispatch stack. When the amount of renewable energy on the grid increases, this reduces the marginal cost of generating the next unit of electricity. All else equal, a lower marginal cost will reduce the avoided energy rates as they are calculated today.

obligation through pricing established in a competitive solicitation."[92] FERC has determined that, if a competitive solicitation is consistently held, is open and non-discriminatory, and meets certain other minimum standards,[93] the competitive solicitation could be used to set avoided cost rates.

Duke indicated during the 2022 Solar Procurement stakeholder process that it intends to hold regular, annual competitive solicitations that align with each DISIS grouping study. According to Duke, these solicitations would be expanded to solar and S+S in future solicitations, reflecting the ownership requirements in Section 110.9. As such, it is likely that future avoided cost rates will be based upon the results of competitive solicitations, rather than determined through the production cost modeling that underlies the current peaker methodology. At this time, the Public Staff requests that Duke discuss in a supplemental filing: (1) whether the 2022 Solar Procurement meets the minimum standards defined by FERC; (2) if not, what modifications would be necessary to meet those standards

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[92] *See* the Companies' response to Commission Order Requesting Answers on 2022 Solar Procurement Program Petition in Docket Nos. E-2, Sub 1297 and E-7, Sub 1268, filed April 29, 2022, at 4.

[93] These standards are defined as: "(i) the solicitation process is an open and transparent process that includes, but is not limited to, providing equally to all potential bidders substantial and meaningful information regarding transmission constraints, levels of congestion, and interconnections, subject to appropriate confidentiality safeguards; (ii) solicitations must be open to all sources, to satisfy that purchasing electric utility's capacity needs, taking into account the required operating characteristics of the needed capacity; (iii) solicitations are conducted at regular intervals; (iv) solicitations are subject to oversight by an independent administrator; and (v) solicitations are certified as fulfilling the above criteria by the relevant state regulatory authority or nonregulated electric utility through a post-solicitation report." FERC Order 872, at 122.

in a 2023 Solar Procurement proceeding; and (3) if so, whether it is appropriate to use the results of the competitive solicitations to set avoided cost rates and provide a calculation methodology to establish those rates. If the Commission should determine that there is an avoidable cost of carbon, it should also direct Duke to include it in the calculation of avoided energy rates in Duke's next avoided cost proceeding.

2022 Solar Procurement Target Capacity

In Chapter 4 of the Proposed Carbon Plan, Duke proposes to procure 750 MW of new solar resources through the 2022 Solar Procurement Program.[94] Per the terms of the 2022 Solar Procurement, 55% of the total capacity would be utility-owned and 45% would be procured through third-party PPAs. Duke states that this target capacity balances the need to continue adding large quantities of solar capacity to the transmission system against the current environment of rising prices. As Duke acknowledges, "the Companies cannot simply wait until market conditions stabilize and expect to hit the 70% interim target."[95]

As acknowledged by Duke, the 750 MW target for the 2022 Solar Procurement is determined by the Proposed Carbon Plan and the assumptions

[94] *See* Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Petition for Authorization of 2022 Solar Procurement Program, Docket Nos. E-2, Sub 1297 and E-7, Sub 1268 (filed March 14, 2022).

[95] *See* Proposed Carbon Plan Appendix I at 9.

regarding interconnection capacity. The interconnection limit in the model for new solar projects coming online in 2026 was set at 750 MW. That constraint is binding, as the model economically selected 750 MW in 2026 and reached its interconnection limits in subsequent years. However, this upper limit on interconnections is an engineering judgement based on several factors, which the Companies outline in Proposed Carbon Plan Appendix I. While the Public Staff acknowledges that the pace of interconnections necessary to meet the interim target of 70% CO_2 reduction is high, it also believes that the most efficient way for Duke to expand the necessary interconnection capabilities and to streamline transmission upgrades is to pursue them in large quantities. In addition, Duke's ongoing efforts to improve and shorten its interconnection process, described in Proposed Carbon Plan Appendix I, are critical elements of meeting the Section 110.9 targets.

The Public Staff believes it is not appropriate to use historical interconnections as a gauge or limit on future interconnections. First, in the last several years solar facilities have increased in size and began interconnecting to the transmission system. Duke is no longer interconnecting the large quantities of 5 MW or less facilities to the distribution system that currently make up a majority of DEP's operational solar capacity. While larger projects can be more complex and trigger more upgrades, fewer total projects could possibly free up labor and material constraints. In North Carolina alone, Duke has interconnected an average of 72 solar projects per year from 2015 to 2020.[96] Interconnecting between 10 and 15 larger projects a year will represent a significant decrease in the number of projects that require interconnection facilities and contractual obligations.

Second, the 2022 Procurement is the first time Duke has performed the DISIS, which is the cluster study process within the Commission-approved queue reform.[97] In its queue reform proposal, Duke noted the same complexities, increasing transmission costs, and interdependencies that it describes in Proposed Carbon Plan Appendix I, and stated that "undertaking more significant queue reform by transitioning to the DISIS Process is an important step to achieving the State's goals of continuing to increase renewable energy penetration on the Companies' systems in a safe, reliable, and efficient manner."[98] The Public Staff understands the technical challenges associated with interconnecting large quantities of solar capacity but also believes that a larger and more robust solar procurement will both increase the likelihood that the 70% CO_2 reduction target will be met and help serve as validation that the RZTEP Duke has identified in

[96] This figure does not include South Carolina projects and is based on the Public Staff's analysis of Schedule B of the North Carolina Annual Interconnection Report, filed in Docket No. E-100, Sub 113B.

[97] On October 15, 2020, the Commission issued an Order Approving Queue Reform, which approved the queue reform proposal as filed by Duke on August 31, 2020. On August 6, 2021, FERC issued an Order approving queue reform. On August 19, 2021 Order Implementing Queue Reform, in Docket No. E-100, Sub 101.

[98] *See* DEC and DEP Queue Reform Proposal, filed May 15, 2020, in Docket No. E-100, Sub 1010, at 19.

Proposed Carbon Plan Appendix P are part of a no-regrets proactive approach to transmission planning.

Therefore, the Public Staff does not support Duke's proposed 2022 Solar Procurement target of 750 MW. The Public Staff has closely followed the CPRE Program, and notes that projects selected as winners can still terminate their PPAs years after project evaluation, selection, and contracting has been completed. If Duke pursues only 750 MW in the 2022 SP, less than 750 MW may reach commercial operation. Thus, the Public Staff has taken a more forward-looking approach to determining the 2022 Solar Procurement quantities.

In Table 4 below, the Public Staff summarizes solar additions in the Proposed Carbon Plan. The first category is Forecasted Solar, which is solar that Duke forces into the model for every portfolio. This solar capacity is expected to become operational outside of any Carbon Plan procurement processes and includes solar capacity that is mandated by programs such as CPRE, Green Source Advantage, and South Carolina Act 236, or is expected to materialize through the interconnection queue as PURPA projects. Notably, these figures include CPRE Tranche 3 capacity of 596 MW in DEC in all portfolios.

The second category shows the total solar and S+S added by 2030, inclusive of forced solar and economically selected solar. The Public Staff reviewed all four primary portfolios as well as all four alternative portfolios to determine the minimum and maximum amount of solar added in any portfolio.

Subtracting the forced-in solar from the total solar leaves the amount of solar that was economically selected by the Proposed Carbon Plan model. This amount ranges from 3,381 MW to 5,331 MW that must be procured prior to 2030. However, the forced in solar includes the full 1,782 MW CPRE target and does not reflect recent developments in CPRE—namely, that only 155 MW of capacity in Tranche 3 of the CPRE remains (a 441 MW shortfall),[99] and that two projects totaling approximately 150 MW may drop out of Tranche 2. Adding this 591 MW of CPRE shortfall to the economically selected solar and averaging over four years shows Duke must procure between 993 MW and 1,481 MW annually to meet the Section 110.9 targets.

[99] *See* Rebuttal Testimony of Angela M. Tabor, filed in Docket No. E-7, Sub 1262, at 5.

Table 16: Solar in the Carbon Plan

Solar Type	Solar MW, 2022 – 2030	
	Minimum	Maximum
DEC Forecasted Solar (Forced in)[100]	1,633	1,633
DEP Forecasted Solar (Forced in)	304	304
Total Forecasted Solar (Forced in)	1,938	1,938
DEC Solar Added (total)	3,249	3,849
DEP Solar Added (total)	2,069	3,419
Total Solar Added (total)	5,319	7,269
DEC Solar Added (economically selected)	1,616	2,216
DEP Solar Added (economically selected)	1,765	3,115
Total Solar Added (economically selected)	3,381	5,331
Projected CPRE Shortfall	591	591
Total Solar Required	3,972	5,922
Total Annual Solar Required (four years)	993	1,481

The Public Staff seeks balance between robust market participation in the 2022 Solar Procurement and the risk that procuring too much solar this year could result in higher prices for ratepayers, given the unprecedented supply chain challenges facing the industry. Therefore, the Public Staff recommends that the Commission approve a target quantity of at least 1,000 MW in the 2022 SP, which represents a "least regrets" approach to meeting the 70% CO_2 reduction goal. If the Commission agrees with the Public Staff's recommendation in the 2022 Solar Procurement proceedings, the target capacity could be as much as 2,000 MW to

[100] The "forced in" solar includes mandated programs such as CPRE.

be placed in service between 2026 and 2027, reflecting two years of required solar additions.[101] This target capacity would be adjusted up or down once bids have been received and compared to Duke's Solar Reference Cost, inclusive of network upgrades.

The Public Staff also notes that in the Proposed Carbon Plan, Duke used constraints to force 60% of new solar into DEP and 40% into DEC. The Public Staff prefers to see those constraints lifted and let the model optimally select solar in each Company's territory; however, doing so would require Duke to estimate the costs of DEC and DEP solar into the model, considering differences in land costs, labor costs, and other factors that differentiate each Company's territory. Currently, the model uses a generic reference cost and operational characteristics for solar that are not substantially differentiated between the Companies. Therefore, the Public Staff recommends that for the 2022 Solar Procurement, the Commission direct Duke to select the most competitive bids across both jurisdictions without forcing a split between DEC and DEP. However, in the next Carbon Plan, Duke should utilize the results of the 2022 Solar Procurement to create solar resources in the EnCompass model that reflect actual bids received in DEC and DEP territories and allow the model to select solar optimally across the combined territories based on economic factors.

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[101] *See* the March 28, 2022 Initial Comments of the Public Staff, Docket Nos. E-2, Sub 1297 and E-7, Sub 1268, paragraph 19 at 10-11.

The Public Staff's Recommendations on Duke's Request for Relief

Section X. Conclusion and Request for Relief of Duke's Verified Petition for Approval of Carbon Plan asks the Commission to adopt the Proposed Carbon Plan and take specific actions as listed below. The Public Staff's responses are at the end of each item.

1) Affirm that the Companies' Carbon Plan modeling is reasonable for planning purposes and presents a reasonable plan for achieving Section 110.9's authorized CO_2 emissions reductions targets in a manner consistent with Section 110.9's requirements and prudent utility planning;

Response: While Duke made significant efforts to model its proposed Carbon Plan, the Public Staff found problems with some of the modeling assumptions that it was not able to resolve. The Public Staff asks the Commission to consider the Public Staff's comments in the Public Staff Recommendations section and to require Duke to produce the modified Portfolio 5. Once these problems are resolved and the Public Staff has reviewed the modified Portfolio 5, the Public Staff will be in a better position to make a recommendation on this request.

2) Approve the near-term supply-side development and procurement activities identified in Table 3 in the Executive Summary, including by:

a) Deeming the following resources as being selected in this initial Carbon Plan for purposes of Section 110.9, Section 1.(2), in all cases subject to the obligation to obtain a CPCN (where applicable) and to keep the Commission apprised of material changes in assumed pricing or schedule:

   i) 3,100 MW of solar generation (including 750 MW requested to be procured through the 2022 Solar Procurement Program), of which a substantial portion is assumed to include paired with storage;

   ii) 1,600 MW of battery storage (1,000 MW stand-alone storage, 600 MW storage paired with solar);

   iii) 600 MW of onshore wind;

   iv) 800 MW of CTs; and

   v) 1,200 MW of CC

Response: The Public Staff recommends that the Commission first require Duke to submit the modified P5 model run and to the extent that the identified resources above are still selected, approve Duke's near-term (2022 to 2024) supply-side development and procurement activities identified in Table 3 in the Executive Summary. The Commission's approval should be subject to continuing review in the utilities' integrated resource planning and Carbon Plan processes, as well as required CPCN processes identified in G.S. 62-110.1 and Commission

Rules R8-61. These activities are common to all portfolio options, specifically items (i) through (v) above. The Public Staff also recommends that the 2022 Solar Procurement Program target at least 1,000 MW of solar capacity.

b. Approving the Companies' plans to pursue initial development activities to support the future availability of offshore wind, SMRs, and new pumped storage hydro at Bad Creek to ensure that these resources are available options for the Companies' customers on the timelines identified in the portfolios if selected in future Carbon Plan updates;

Response: The Companies should take appropriate actions to implement the Carbon Plan that will be developed by the Commission, to the extent that such actions are prudent and reasonable. However, the Public Staff does not recommend that the Commission approve such actions for ratemaking or other purposes prior to the time that the same or similar actions would normally be approved under existing statutory authority or Commission practices. (For example, as noted below, the approval granted by N.C.G.S. § 62-110.7 only applies to limited nuclear project development activities). The Public Staff recognizes that offshore wind, SMRs, and new pumped storage hydro at Bad Creek are resources common to most portfolio options. However, the Public Staff notes that the regulated utilities do not currently hold any offshore wind leases, nor have they filed any affiliated contracts for any non-regulated affiliate of the regulated utilities regarding the lease of offshore wind areas.

c. Making the following additional determinations with respect to the project development activities summarized in Table 3 in the Executive Summary:

    i. Engaging in initial project development activities for these resources is a reasonable and prudent step in executing the Carbon Plan to enable potential selection of these generating facilities in the future;

Response: The Public Staff believes the Companies should take appropriate actions to implement the Carbon Plan approved by the Commission, to the extent that such actions are prudent and reasonable. However, the Public Staff does not recommend that the Commission approve such actions for ratemaking or other purposes prior to the time that the same or similar actions would normally be approved under existing statutory authority or Commission practices.

The Companies have stated:

> This forward-looking approval is necessary and appropriate in this unique context where substantial development activities are needed in advance of final selection by the Commission in order to ensure that such resources can achieve commercial operation on a timeline consistent with the Companies' proposed portfolios and HB 951's targeted timelines. Such forward-looking approval is also consistent

> with N.C. Gen. Stat. § 62-110.7, which contemplates the Commission's preapproval of project development costs in connection with a potential nuclear electric generating facility.

However, N.C.G.S. § 62-110.7 pertains only to costs for potential nuclear electric generation incurred before the issuance of a certificate under N.C.G.S. § 62-110.1 for a facility located in North Carolina or issuance of a certificate by the host state for an out-of-state facility to serve North Carolina retail customers. While a portion of the Companies' proposed plans does contain potential nuclear generation that may be eligible for project development cost deferral on a case-by-case basis, the remaining projects proposed for initial project development costs do not meet the specific criteria set out in N.C.G.S § 62-110.7.

In its response to a Public Staff discovery request, Duke stated that:

> [T]he Companies' request in this proceeding for approval of certain development costs (including development costs for SMRs) is functionally the same as Commission pre-authorization to incur project development costs under N.C. Gen. Stat. 62-110.7 (and the Commission is free to deem such approval for SMR development costs as occurring under N.C. Gen. Stat. 62-110.7). The Companies believe a Commission determination on this issue is appropriate at this time, which would obviate a need for any subsequent application under N.C. Gen. Stat. 62-110.7.

The Public Staff disagrees with Duke's contention that if the Commission made the requested finding, there would be no need to meet the requirements of N.C.G.S. § 62-110.7. While there may be some redundancy in the review of the Carbon Plan and a review of a request under N.C.G.S. § 62-110.7, the parties have not had adequate time to review any request to incur nuclear development costs in sufficient detail while they reviewed the proposed Carbon Plan with its four scenarios and multiple types of generation and supply-side resources. Further, as to the contention that resources other than nuclear could receive the same treatment as provided for nuclear in N.C.G.S. § 62-110.7, the Public Staff notes that if the General Assembly had wished to expand the project development statute to cover technologies other than nuclear facilities, it would have done so when it enacted either N.C.G.S §§ 62-110.7 or 62-110.9.

ii. To the extent not already authorized under applicable accounting rules, the Companies are authorized to defer associated project development costs for recovery in a future rate case (including a return on the unamortized balance at the applicable Companies then authorized, net-of-tax, weighted average cost of capital), subject to the Commission's review of the reasonableness and prudence of specific costs incurred in such future proceeding;

Response: It is premature at this time to authorize any deferrals related to the Carbon Plan. Deferral requests should be handled on a case-by-case basis, include full and detailed costing, including cost breakdowns between O&M and capital costs, and be subject to the two-prong test of extraordinariness and magnitude, or such other criteria that the Commission considers relevant and important at the time. At the present time, the Companies have been unable to provide a breakdown of estimated costs between O&M and capital costs for the projects for which it is seeking deferral treatment. Furthermore, Duke has an obligation to meet the carbon reduction requirements of Section 110.9 and has not shown how the projects depicted in their plans are outside the normal course of business. Finally, as previously stated in the Public Staff's response to Section 2(c)(i) above, the only existing statute that prescribes special ratemaking treatment for project development costs is found in N.C.G.S. § 62-110.7, which refers only to capital costs plus AFUDC for <u>**nuclear facilities**</u>. [emphasis added] While SMRs are nuclear facilities, Duke is unable at this time to identify the breakdown of costs between capital costs and O&M costs; therefore, the Public Staff is unable to determine which initial project development costs might be eligible for special treatment.

iii. That in the event the long lead time resources are ultimately determined not to be necessary to achieve the energy transition and the CO_2 emission reduction targets of HB 951, such project development costs will be recoverable through base rates over a period of time to be determined by the Commission at the appropriate time;

Response: It is premature at this time to authorize any potential recovery of abandoned plant costs related to the Carbon Plan. Prospective authorization to recover abandoned plant costs would remove critical checks on the Companies' spending that have historically helped ensure capital expenditures are reasonable and prudent throughout the life of a project. Requests for recovery of abandoned plant should be handled on a case-by-case basis and held to similar historical standards of treatment of abandoned plant. (Please see the Public Staff's Response to c(ii) above regarding the inapplicability of N.C.G.S. § 62-110.7.)

The Public Staff recommends that the Commission consider any possible ratemaking treatment at the time the project(s) ceases construction, without pre-determining recovery timeframe, allocation, cost category, or whether a return on the unamortized costs is appropriate.

d. Approve the Companies' proposed actions with respect to existing supply-side resources, including through expanding flexibility of the existing gas fleet and continued disciplined pursuit of subsequent license renewals (SLRs) for the Companies' existing nuclear fleet;

Response: Expanding flexibility of the existing gas fleet will allow Duke to maintain system reliability and quality of service while integrating intermittent resources such as wind and solar that may not match customer demand. Pursuing SLRs will allow Duke to continue providing a large amount of carbon-free energy from its existing nuclear fleet. The Public Staff believes the Companies should take appropriate actions to implement the Carbon Plan approved by the Commission, to the extent that such actions are prudent and reasonable. However, the Public Staff does not recommend that the Commission approve such actions for ratemaking or other purposes prior to the time that the same or similar actions would normally be approved under existing statutory authority or Commission practices.

e. Approve the Companies' plans to advance Grid Edge and Customer Programs and to update the underlying determination of the utility system benefits in the Companies' approved DSM/EE Cost Recovery Mechanism;

Response: Any changes to the Companies' approved DSM/EE Cost Recovery Mechanisms should only be considered within a comprehensive DSM/EE Cost Recovery Mechanism Review. Any changes to currently approved programs should be handled within the confines of the specific program docket.

Duke has not yet developed cost estimates for advancing Grid Edge and Customer Programs. The Public Staff is concerned that Duke will not be able to achieve the aggressive Grid Edge and Customer Program savings shown in Tables F-18 and F-19 in Proposed Carbon Plan Appendix F (Electric Load Forecast), which predict a total of approximately 7,000 GWh per year of energy savings by 2030. This level of savings goes well beyond the "Achievable" level in

Duke's Market Potential Study (Attachment IV to the Proposed Carbon Plan). Therefore, the Public Staff does not recommend approval of Duke's plan described in Proposed Carbon Plan Appendix G (Grid Edge and Customer Programs) at this time. Instead, the Public Staff recommends that the Commission use a more realistic UEE forecast in its Carbon Plan, such as the UEE forecasts in Duke's 2020 IRPs scaled up to 2022.

The Public Staff further recommends that Duke continue working with stakeholders and evaluate the feasibility, cost effectiveness, and potential for adoption of its proposed Grid Edge and Customer Programs. Finally, the Public Staff recommends that Duke maximize utilization of its AMI network, customer billing systems, and the data derived therefrom to develop these programs and file them for approval as soon as possible.

f. Acknowledge that Section 110.9 establishes new public policy goals requiring new generation and other resources that will necessarily inform the Companies' transmission system planning processes as outlined in the OATT and direct the Companies to continue to study future transmission needs to reliably implement the Carbon Plan through the NCTPC and other appropriate forums;

Response: The planning and study process for transmission to connect more new generation is currently underway and should continue. The Public Staff agrees that the Proposed Carbon Plan requires revisions and improvements to the transmission planning process in light of the public policy goals established by Section 110.9.

g. Approve the Companies' methodologies outlined in Proposed Carbon Plan Appendix A for tracking compliance with Section 110.9's CO_2 emissions reductions targets and confirm the Commissions' accounting requirements for emissions from new out-of-state resources selected by the Commission (if any) as described above;

<u>Response</u>: The Public Staff agrees.

h. Affirm that the first biennial Carbon Plan update proceeding should be held in 2024 and that the Companies' next biennial IRPs will be held in abeyance to 2024 to align with the Carbon Plan update, as further discussed in Chapter 4 (Execution Plan);

<u>Response</u>: The Public Staff agrees. However, the Companies should still be required to file an IRP update, as specified by Commission Rule R8-60(h)(2) and (j), in 2023.

i. Direct the Companies and Public Staff to develop and propose for comment by January 31, 2023, revisions to the Commission's IRP Rule R8-60 and related rules for certificating new generating facilities to support execution of the adopted Carbon Plan;

<u>Response</u>: The Public Staff agrees that revisions to Commission Rule R8-60 are necessary, but requests that the comment due date be April 28, 2023, to allow more time for all parties to develop draft rules.

<u>Issues for Evidentiary Hearing</u>

In its April 1, 2022 Order Establishing Additional Procedures and Requiring Issues Report, the Commission directed intervening parties to identify in their July 15, 2022 filings "the substantive issues, if any, that should be the subject of an expert witness hearing." The Public Staff believes the following issues should be the subject of an expert witness hearing before the Commission:

1. Proactive transmission upgrade planning;
2. Approval of the near-term development activities outlined in Duke's Petition;
3. The Public Staff's recommendation that Duke, in the 2024 Carbon Plan filing and the next general rate cases, propose cost allocations that address the rate disparity between DEC and DEP and equitably allocate costs of new generation and transmission in a manner that is proportionate to the benefits received by each utility's customers as an interim measure; and

4. The Public Staff's recommendation that Duke should promptly evaluate the steps necessary to consolidate the DEC and DEP utilities into a single operating entity and present the Commission with a timeline for implementation.

In addition, the Public Staff has recommended that Duke run the requested P5 model and submit the results as a supplemental filing no later than August 19, 2022. The Public Staff anticipates that Duke will be able to complete the requested model run, potentially with certain modifications agreeable to the Public Staff. However, if Duke believes certain specific recommendations are not able to be included in the P5 model run, the Public Staff recommends that those contested recommendations related to P5 be resolved in an evidentiary hearing.

Last, if the Commission determines that the request in Duke's Petition to defer project development costs for recovery in a future rate case is appropriate to consider in this proceeding, this issue should be resolved in an evidentiary hearing. The Public Staff reiterates, however, that deferral requests should be handled on a case-by-case basis, and that it is premature in this proceeding to authorize any deferrals related to the Carbon Plan.

The Public Staff appreciates the opportunity to identify the issues it believes should be the subject of an expert witness hearing in these comments, and notes that it may identify additional issues upon reviewing the comments of other intervenors. In that event, the Public Staff will communicate those additions to Duke so that they are properly reflected in the Issues List filed by Duke on July 22, 2022.

Conclusion

The Public Staff appreciates the opportunity to submit these comments on Duke's Proposed Carbon Plan and respectfully requests that the Commission take the findings and recommendations presented herein in consideration when developing its Carbon Plan.

Respectfully submitted this 15th day of July, 2022.

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CERTIFICATE OF SERVICE

I certify that I have served a copy of the foregoing Comments on all parties of record 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.

This the 15th day of July, 2022.

Electronically submitted
/s/ Nadia L. Luhr