BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 190

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

June 19, 2024

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

A. My name is David M. Williamson. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an engineer with the Energy Division of the Public Staff – North Carolina Utilities Commission.

Q. Briefly state your qualifications and experience.

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

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

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

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

A. The purpose of my direct testimony is to set forth my findings and recommendations resulting from my examination of the Verified Petition for Approval of Duke Energy Progress, LLC's (DEP) and Duke Energy Carolinas, LLC's (DEC, and together with DEP, the Companies or Duke) 2023-2024 Carbon Plan and Integrated Resource Plan (CPIRP) filed in Docket No. E-100, Sub 190, on August 17, 2023 (Application); the Companies' direct testimony filed on September 1, 2023; and the Amended Petition and supplemental direct testimony filed by the Companies on January 31, 2024 (Supplemental Planning Analysis or SPA). The CPIRP provides the Companies' proposed path for carbon emission reductions as required by N.C.G.S. § 62-110.9 (Section 110.9 or HB 951). The August 17, 2023 filing uses a Spring 2023 load forecast and the SPA uses a Fall 2023 load forecast that reflects updated and higher load growth projections.

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

A. The scope of my investigation includes a review of the Companies' current Grid Edge[1] activities and the long-term influences of those activities on the load forecast. Additionally, my investigation includes a review of the Companies' bill impact analysis that shows the long-term cost increases that retail electric customers will experience as a result of the proposed compliance portfolio. My investigation incorporates the Companies' originally filed Spring 2023 load forecast and the SPA Fall 2023 load forecast. Public Staff witnesses John R. Hinton and Patrick Fahey, referred to as the Load Forecast Panel, discuss the Companies' load forecasts in detail in their joint testimony in this proceeding.

Q. How is your testimony organized?

A. My testimony is organized as follows:

I. Grid Edge Overview
   a. Rooftop Solar and Net Metering
   b. Electric Vehicles (EVs)

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[1] In the context of the CPIRP, Grid Edge refers to technologies, programs, and investments that advance a decentralized, distributed, and two-way grid by reducing or managing energy loads in ways that allow for the deferral or elimination of additional generation resources. *See* Docket No. E-100, Sub 190, Carolinas Resource Plan, Appendix H, filed on August 17, 2023.

c. Rate Design

d. Energy Efficiency (EE)

e. Demand-Side Management (DSM)

II. Grid Edge Requests for Relief

III. Bill Impacts

Q. Are you providing any exhibits with your testimony?

A. Yes. I am including 6 exhibits, described below:

Williamson Exhibit 1.	DEC – 2022 Carbon Plan – Grid Edge Forecast
Williamson Exhibit 2.	DEC – 2023 CPIRP (SPA) – Grid Edge Forecast
Williamson Exhibit 3.	DEP – 2022 Carbon Plan – Grid Edge Forecast
Williamson Exhibit 4.	DEP – 2023 CPIRP (SPA) – Grid Edge Forecast
Williamson Exhibit 5.	DEC – 2023 CPIRP (SPA) Projected Bill Impacts
Williamson Exhibit 6.	DEP – 2023 CPIRP (SPA) Projected Bill Impacts

Q. Please summarize your recommendations.

A. My recommendations are summarized as follows:

1. That the impacts associated with PowerPair be included in the rooftop solar and net metering forecast and reflected within the base modeling assumptions, as reflected in the Public Staff's base modeling assumptions;

2. In the next CPIRP proceeding, the Companies should re-evaluate removing EV load from the eligible retail sales target of 1% and provide a detailed discussion on the reasonableness of treating EV load similar to the treatment of DSM/EE opt-out load for purposes of the 1% of eligible retail sales target;

3. The Commission should allow the Companies to use 1% of eligible load annual EE savings as the annual floor or minimum load modifier for the CPIRP modeling;

4. The Commission should approve the Companies' plans to continue advancing Grid Edge and customer programs; and

5. The Companies should include in future CPIRP filings all known and approved rate changes in their bill impact analysis.

I. GRID EDGE OVERVIEW

Q. What are Grid Edge activities?

A. Grid Edge is a collection of tools and technologies that include the following: the Companies' portfolio of DSM and EE programs, EV charging, renewable energy systems like rooftop solar, and storage. These technologies also are referred to as "Distributed Energy Resources" (DERs). Additionally, Grid Edge includes new rate tariffs that employ a variety of price signals to motivate customers to shift usage from higher-cost, on-peak hours, to lower-cost, off-peak hours. The Companies describe these tools and technologies in Appendix H of the CPIRP.

Q. How are the Companies modeling Grid Edge activities?

A. While load forecasting has always incorporated the various ways customers use energy, the requirements set forth in S.L. 2021-165 (referred to as HB 951) necessitate a more sophisticated review and consideration of DERs and how they can impact peak demands and energy sales and, as a result, reduce carbon emissions. To more accurately forecast customer energy and capacity requirements across the planning horizon set forth in the CPIRP, the Companies have expanded their load forecast modeling to include these Grid Edge activities to provide a more accurate representation of their supply-side resource needs.

Also, pursuant to Commission Rule R8-60A(e) and (f), the Companies must file base load forecasts every two years. This biennial review allows the Companies to update their individual Grid Edge forecasts to reflect current regulatory conditions and customer adoption trends. These Grid Edge forecasts allow for a more complete picture of the overall gross-to-net load forecasting, as Grid Edge can reduce the gross load. A detailed discussion on the gross load forecast can be found in the direct testimony of the Public Staff's Load Forecast Panel. Together, the Grid Edge forecast and the gross load forecast create the net load forecast (Net Load Forecast) that is used to create the annual load requirement needs that the Companies' model will need to resolve.

Q. What data is used to create the individual Grid Edge forecasts?

A. In this proceeding, the Companies have layered individual forecasts of Grid Edge programs that affect modeling assumptions from the Spring 2023 load forecast. These assumptions were further updated as part of the SPA in order to adjust the Companies' load forecast for program participation and savings. This process creates the Net Load Forecast that is used in every year of the model to determine various mixes of resources required to satisfy the load requirements of that given year. The difference between the Spring 2023 load forecast and the SPA forecast will be discussed in the joint testimony of the Public Staff's Load Forecast Panel. My testimony focuses on changes since the 2022 Carbon Plan that have impacted the Grid Edge forecast, and the resulting effect on the Net Load Forecast in the Companies' preferred portfolio (Portfolio 3 Fall Base or P3 Fall Base) in this CPIRP.

The changes from the 2022 Carbon Plan Grid Edge forecast to the forecasts embedded as part of the SPA are illustrated below:

Figure 1: DEC's 2022 Carbon Plan Grid Edge Forecast

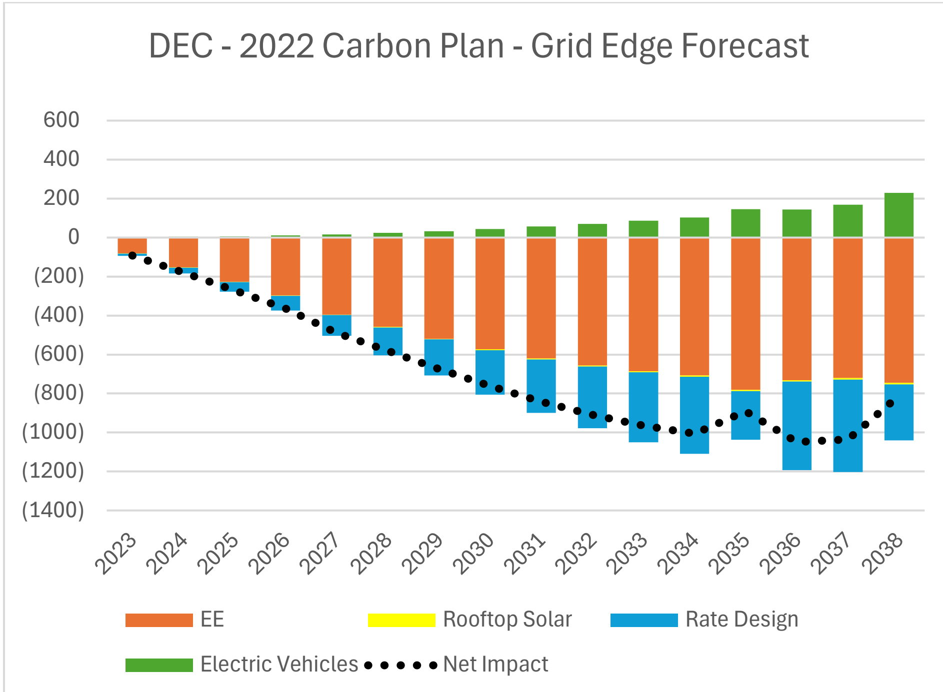


Figure 2: DEC's SPA Grid Edge Forecast

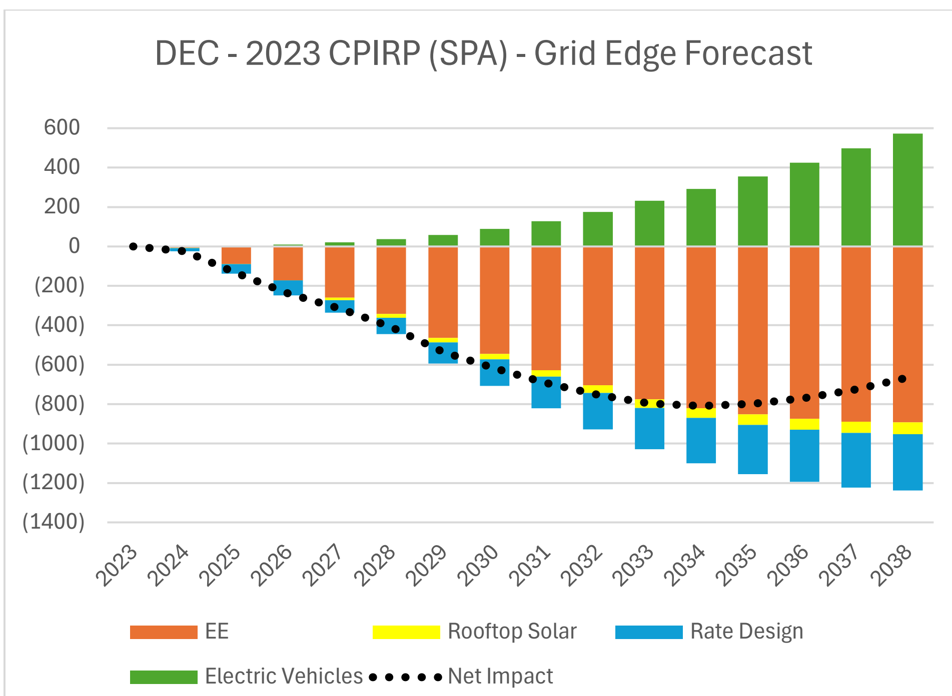


Figure 3: DEP's 2022 Carbon Plan Grid Edge Forecast

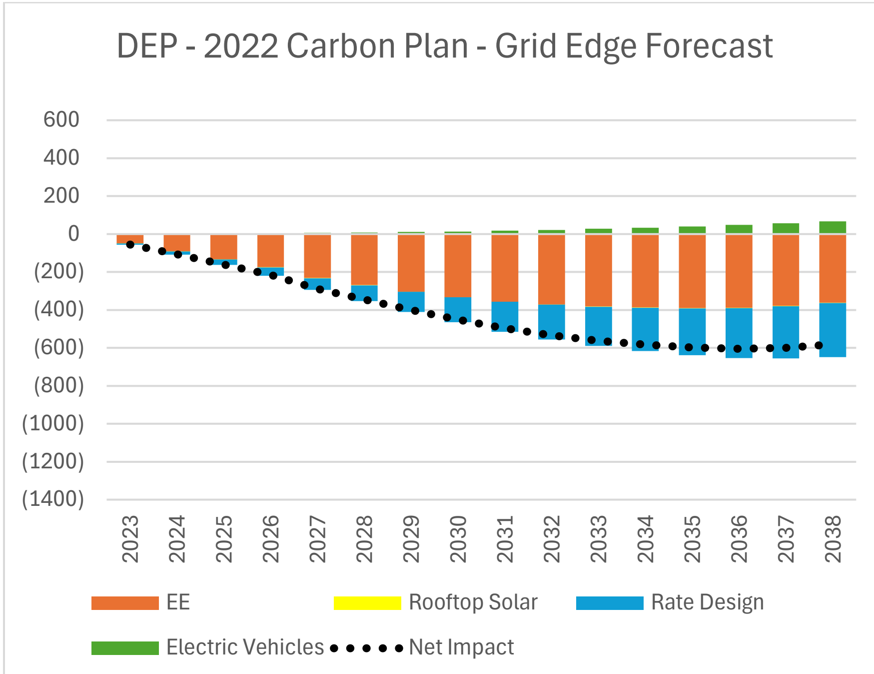
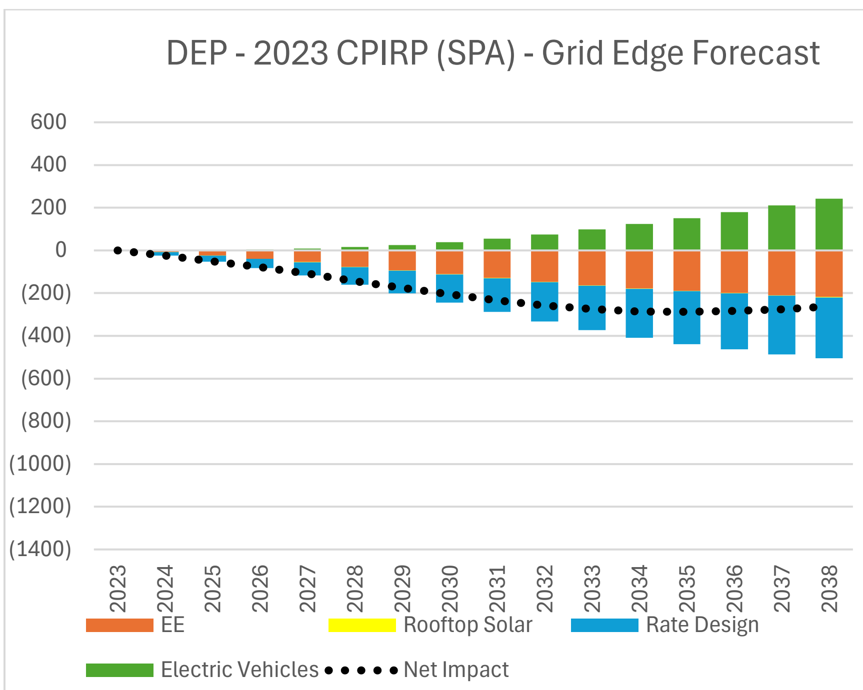


Figure 4: DEC's SPA Grid Edge Forecast



Williamson Exhibits 1 through 4 include these graphs with additional details for each portfolio on an annual basis.

My review of the Companies' Grid Edge forecasts is detailed below:

Rooftop Solar and Net Metering

Q. What is included in the analysis of rooftop solar and net metering?

A. The forecast of demand and energy savings from net metering includes impacts of behind-the-meter solar and storage. These technologies work in tandem and their impacts in Grid Edge forecasting have been modeled in that manner.

Q. What has changed with rooftop solar and net metering since the Commission issued its order in the 2022 Carbon Plan proceeding?

A. Two key factors have changed that will impact the forecast going forward. First, as part of the Commission's Order Approving Revised Net Metering Tariffs, issued on March 23, 2023, in Docket Number E-100, Sub 180, the Commission approved revised tariffs for residential net metering customers, effective October 1, 2023. The revised tariffs update existing components of net metering rates and add new billing components to recover necessary and appropriate electric service costs from net metering customers.

Second, the Commission approved the Companies' PowerPair program on January 11, 2024, in Docket Nos. E-2, Sub 1287; and E-7, Sub 1261. The PowerPair program provides customers with a combination of rebates on solar and storage technologies that are based on the technology's rated capacity as well as an option to enroll storage devices into the Companies' DSM program offerings.

Q. Were these updates considered in the modeling for rooftop solar and net metering?

A. Partially. The Companies' Spring 2023 forecast did not include the demand and energy savings of either the revised net metering tariffs or the PowerPair program. However, as part of the SPA, the Companies did include the impact of the new net metering rate tariffs.

The Spring 2023 forecast did not include the impact of the PowerPair program because it was not approved at the time. While customers have been able to apply for the PowerPair program since May 10, 2024, the program's projected impacts were not incorporated into the Companies' SPA but will be incorporated into the next CPIRP forecast. However, using information received through discovery, the Public Staff incorporated the projected impacts of the PowerPair program into the forecast for its base portfolio (PS Base 2034).

Q. Has the Public Staff modeled sensitivities related to impacts associated with rooftop solar and net metering?

A. Yes. As discussed in greater detail in the direct testimony of Public Staff witness Jeff Thomas, the Public Staff modeled several sensitivities, including the assumption that DEC and DEP both doubled their estimated impacts resulting from net metering.

Q. Please comment on the feasibility of doubling contributions from rooftop solar and net metering.

A. The Companies' current net metering assumptions include the impact of the most recent changes to the net metering rates as well as an assumption that all participating customers are subscribed to time-of-use rates that would alter customer usage patterns for maximum system benefit. While the Companies have new incentives and pricing structures since the 2022 Carbon Plan, the rate of adoption of net metering and battery storage is within customers' control.

As noted in Public Staff witness Thomas' Table 11, doubling the load reduction attributable to net metering would significantly reduce costs to ratepayers. However, I do not believe that this assumption is currently achievable, unless further incentives are provided either by the Companies or through State and federal government rebates to incentivize more customers to install rooftop solar.

Q. Should the Commission accept the Companies' 2023 Fall forecast with respect to rooftop solar and net metering?

A. For the purpose of this CPRIP, I recommend that impacts associated with PowerPair be included in the rooftop solar and net metering forecast and reflected within the base modeling assumptions. Public Staff witness Thomas has included these impacts in the Public Staff's base modeling assumptions.

<u>Electric Vehicles</u>

Q. What is included in the analysis of EV load?

A. Duke is constantly reviewing how EV load growth is materializing year-over-year so that the Companies can model the needs and constraints of the grid. While results of the Companies' check-and-adjust process for EV load growth are ever changing, the Companies provided a current assessment of EV load growth in North Carolina. Further detail on the various programs and modeling assumptions utilized in the EV forecast can be found in the direct testimony of Public Staff witness Evan D. Lawrence.

Q. Should the Commission accept the Companies' 2023 Fall forecast with respect to EV load?

A. Yes. As recommended by Public Staff witness Lawrence, the Commission should accept the Companies' EV load forecast as presented in the Companies' SPA.

<u>Rate Designs</u>

Q. What is included in the Companies' analysis of rate designs with respect to the Net Load Forecast?

A. The Net Load Forecast includes savings assumptions from new rate designs that will encourage customers that have technologies like behind-the-meter solar and storage and EVs to reduce their peak load. Currently, the rate designs used in the Net Load Forecast are the Critical Peak Pricing and Peak Time Rebate tariffs.

Q. Has the Public Staff modeled sensitivities related to new rate designs?

A. Yes. As discussed in greater detail in the direct testimony of Public Staff witness Thomas, the Public Staff modeled several sensitivities, including the assumption that DEC and DEP both double their estimated demand and energy savings resulting from new rate designs.

Q. Please comment on the feasibility of doubling contributions from new rate designs.

A. The Companies have modeled innovative rates that encourage demand reduction and energy savings. As seen in the figures above, little has changed with this component of Grid Edge since the 2022 Carbon Plan. However, as part of the Companies' most recently concluded general rate cases, the Commission approved a performance incentive mechanism that incentivizes the Companies to develop and increase customer adoption of rates that encourage customers to use energy at off-peak times. The impacts associated with innovative rate designs are always dependent on the Companies' customer base enrolling in those rate offerings and using energy in the manner contemplated by that rate offering. This dependency on customer adoption and the new performance incentive mechanism should appropriately incentivize the Companies to market any new rate offerings to the greatest extent possible.

As noted in witness Thomas' Table 11, doubling demand and energy savings through Grid Edge would significantly reduce costs to ratepayers. However, until the Companies develop more and better rate designs, or customer participation increases as a result of these new rate designs, I do not believe that doubling the demand and energy savings is currently achievable.

Q. Should the Commission accept the Companies' forecast with respect to rate design?

A. Yes. For the purposes of this CPIRP, the underlying forecast resulting from the Companies' rate designs is appropriate and should be accepted.

Energy Efficiency

Q. How did changes in the Companies' EE programs affect the Net Load Forecast?

A. The Companies have included their currently approved EE programs in the Net Load Forecast through the planning horizon but do not include programs that are new or still pending before the Commission. The Companies will include the impacts of new programs in future CPIRPs, which I find to be reasonable and consistent with prior planning approaches.

Q. What programs are not included in the EE Forecast?

A. Table 1, below, shows the Companies' new EE programs or programs modified since the conclusion of the 2022 Carbon Plan proceeding, the incremental savings of which have not been incorporated into the CPIRP.

Table 1: Recent EE Program Additions or Modifications

DEC EE Programs	DEP EE Programs
Res. Smart $aver Early Replacement and Retrofit	Res. Smart $aver Early Replacement and Retrofit
Res. Smart $aver Modifications	Res. Smart $aver Modifications
Income Qualified EE and Weatherization Assistance	Income Qualified EE and Weatherization Assistance
Res. Energy Education Program for Schools	Res. Energy Education Program for Schools
High Energy Use Pilot	Multi-Family New Construction Pilot

Q. How did the Companies model EE?

A. The Companies modeled EE in the same manner as set forth in the 2022 Carbon Plan. Duke modeled total annual EE savings across the planning horizon by using 1% of prior year eligible retail sales[2] as a minimum target.

Additionally, as a sensitivity, the Companies modeled total annual EE savings using 1.5% of prior year eligible retail sales as a minimum target as ordered by the Commission in its Order Adopting Initial Carbon Plan and Providing Direction for Future Planning issued on December 30, 2022, in Docket No. E-100, Sub 179.

[2] Eligible retail sales are total retail sales minus the sales associated with customers that have elected to opt-out of the Companies' respective DSM/EE riders.

Q. Have the Companies referenced any challenges with achieving the 1% of prior year eligible retail load target?

A. Yes. As discussed on pages 19 through 23 of the direct testimony of Duke witnesses Timothy J. Duff and Jonathan L. Byrd, the Companies believe two factors have increased the challenges of achieving the 1% eligible retail load target that is currently used in the model. The first challenge is the higher customer load growth that is currently projected in the SPA compared to the 2022 Carbon Plan and the Spring 2023 forecasts, and the second challenge is the growth of EV load. While I discuss these challenges below, the Public Staff's Load Forecast Panel provides greater detail on the updated load forecast in their joint testimony, and Public Staff witness Lawrence provides greater detail on the EV load growth projections.

Q. Does the Public Staff agree with the Companies that achieving the 1% of prior year eligible retail load for their EE target is challenging?

A. No. The Public Staff believes that the increased customer load should not affect the Companies' ability to achieve the minimum targets above, since the model only recognizes prior year *eligible* retail sales. Most of the increased load presented in the SPA appears to be from non-residential customers that would have the ability to opt out of the Companies' DSM/EE riders, thus no longer being part of the eligible retail sales aspect of the forecast. Specifically, energy sales from opted-out customers do not contribute to the EE model that is used in the CPIRP. If a customer opts in, then those sales would be included in the underlying assumptions for the 1% prior year eligible retail sales.

For purposes of this proceeding, the Public Staff does not believe that increasing EV load warrants special treatment in the EE modeling projections. Currently, the true pace of EV load growth is unknown. However, the forecasts from the 2022 Carbon Plan to the Fall 2023 forecast show a steady increase in EV load later in the planning horizon. Within the window of the near-term action plan, the Public Staff believes that large load opt-outs and increased EV load should not impair the Companies' ability to achieve the 1% savings goal. I recommend that in the next CPIRP proceeding, the Companies revisit removing EV load from the eligible retail sales target and provide a detailed discussion on the feasibility of treating EV load similar to the treatment of opt-out load in DSM/EE for purposes of the 1% of eligible retail sales calculation.

Q. Has Duke changed its treatment of EE in the CPIRP modeling?

A. As of the date of this testimony, Duke has not made material changes to its treatment of EE in the CPIRP model. However, the outcome of the recently concluded review of the Companies' DSM/EE Cost Recovery Mechanism (Mechanism)[3] will increase the value of EE savings, the customer's incentive to install EE measures, and the Companies' incentives for pursuing greater EE savings.

Q. Has the Public Staff modeled sensitivities related to EE impacts?

A. Yes. As discussed in greater detail in the direct testimony of Public Staff witness Thomas, the Public Staff ran a sensitivity analysis assuming that DEC and DEP both doubled the projected amount of EE savings.

Q. Please comment on the achievability of the Companies' doubling of contributions from EE.

A. As noted above, the Companies' EE assumptions include all currently approved programs as of the filing date of the CPIRP. Additionally, the Companies performed market potential studies to ascertain the energy savings achievable from the different EE programs. Although witness Thomas' Table 11 shows that doubling the load-reducing efforts related to Grid Edge would significantly reduce costs to ratepayers, the current feasibility of achieving such

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[3] *See* the Commission's *Order Approving Revisions to Demand Side Management and Energy Efficiency Cost Recovery and Utility Incentive Mechanisms*, issued on May 22, 2024, in Docket Nos. E-2, Sub 931; E-7, Sub 1032; and E-100, Sub 179.

significant EE savings does not align with the achievable potential identified in the most recent market potential study without a significant shift in the regulatory framework by which EE savings are valued. While the recently concluded Mechanism review includes increases to customer incentives that should increase participation in the Companies' DSM/EE programs, until the Companies can investigate and model the impacts associated with the new Mechanism, I do not believe that doubling the EE forecast is achievable under the current savings assumptions.

Q. Should the Commission accept the Companies' SPA with respect to EE?

A. Yes. For the purposes of this CPIRP, I believe the underlying forecast resulting from the Companies' EE activities is appropriate and should be accepted.

Demand-Side Management

Q. What DSM offerings are included in the CPIRP?

A. DSM offerings included in the forecast embedded in the CPIRP are a combination of both DSM/EE rider-eligible DSM programs (Rider DSM) and DSM activities that are built into the retail rate that a customer is regularly charged (Tariffed DSM), which includes penalties if customers do not shed load when an event is called.

Tariffed DSM programs included in the Companies' forecast include DEC's Standby Generation and Interruptible Service tariffs and DEP's Large Load Curtailable tariff. Additionally, Table 2 below, shows all Rider DSM programs included in the CPIRP model:

Table 2: Current DSM Offerings

DEC DSM Offerings	DEP DSM Offerings
Power Manager	EnergyWise Home
PowerShare Mandatory	Demand Response Automation
PowerShare Generator	Large Load Curtailable
Interruptible Service	EnergyWise for Business
Standby Generator	
EnergyWise for Business	

As discussed in witness Thomas' testimony, most DSM offerings are modeled as supply-side resources, not demand-side resources. As such, rather than simply reducing the Net Load Forecast, the DSM offerings have a predetermined level of available capacity that is influenced by program participation and design. The CPIRP model can then call upon these offerings in a limited manner (reflecting program limitations) to meet demand.

Q. How have the Companies' CPIRP forecasts for DSM changed since the 2022 Carbon Plan order was issued?

A. Figures 5 and 6, below, show the changes in DEC's and DEP's DSM forecasts. These graphs include the forecasts originally filed in the

2022 Carbon Plan and the forecasts filed in the SPA. Specifically, the two graphs below represent the peak contribution on an annual basis for both summer and winter.

Figure 5: DEC's Annual and Seasonal DSM Capability

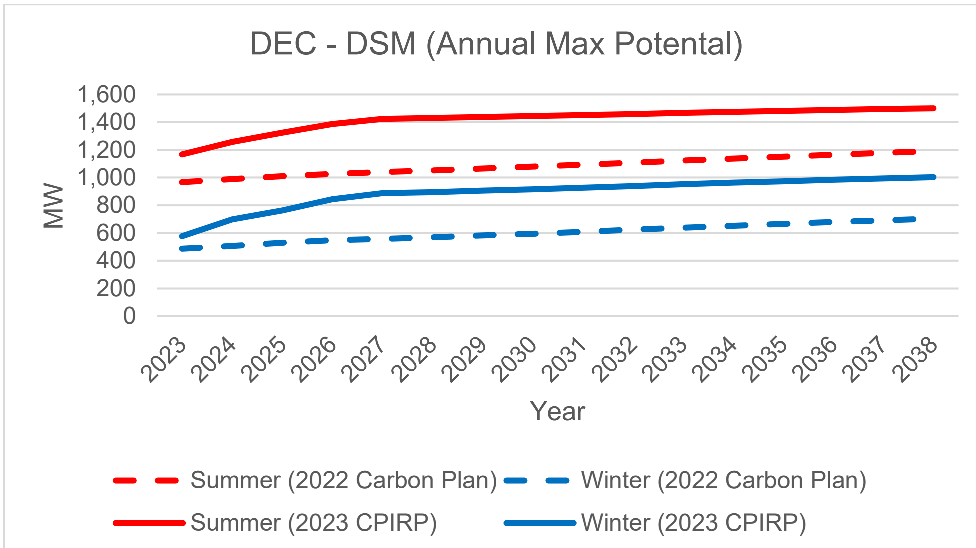
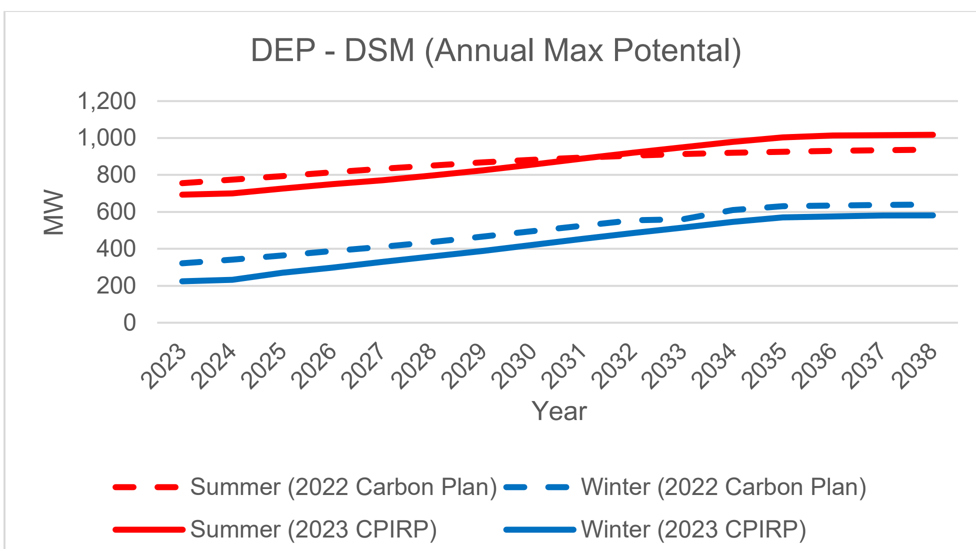


Figure 6: DEP's Annual and Seasonal DSM Capability



With the exception of DEP's winter contributions, the graphs show that the contribution from utility DSM can reduce the peak demand that must be served with other supply-side resources. I would also like to highlight that the available capacity of DEC's DSM portfolio increases from 2023 to approximately 2027, at which point it slows significantly and appears to level off. This is a concern, as it reflects a slower pace of DSM expansion in DEC during the "critical period" between 2027 and 2033, as discussed in witness Thomas' testimony, that could result in a need for additional generation to meet peak demand.

Q. Has the Public Staff modeled sensitivities related to impacts associated with DSM?

A. Yes. A discussion of the EnCompass modeling results for this modeled sensitivity is provided in greater detail in the direct testimony of Public Staff witness Thomas. This sensitivity included the assumption that DEC and DEP both doubled DSM contributions. The cost associated with doubling the contributions from DSM programs was also doubled.

Q. Please comment on the achievability of doubling DSM contributions.

A. As noted above, the Companies' current DSM portfolios are inclusive of both Rider DSM and Tariffed DSM. Similar to the discussion above on EE programs, the Companies are incentivized to maximize a customer's interest in Rider DSM programs. Additionally, as part of the Companies' performance incentive mechanism that resulted from both companies' recent general rate case proceedings, they are both also incentivized to encourage the development and adoption of more Tariffed DSM programs.

Moreover, as noted in witness Thomas' Table 11, the capacity savings that could be achieved through doubling DSM's load-reducing efforts would be significant in reducing costs to ratepayers. Although the Companies have not proposed any new DSM offerings that could double DSM contributions, the updates to the Companies' DSM/EE Mechanism that were recently approved by the Commission should create new and enhanced DSM opportunities for customers, thus improving the DSM forecast going forward.

As I stated earlier, savings achieved through doubling the load-reducing efforts related to Grid Edge would significantly reduce costs to ratepayers, assuming that these programs are as cost-effective as the programs that exist today.

Q. Should the Commission accept the Companies' SPA with respect to DSM contributions?

A. Yes. For purposes of this CPIRP, the underlying forecast for the DSM contributions, as originally proposed by the Companies, is appropriate and should be accepted. I also reiterate the Public Staff's concern that DSM program adoption and available capacity appears to be slowing in DEC during the "critical period" (2027-2023) identified by witness Thomas.

II. GRID EDGE REQUESTS FOR RELIEF

Q. Have the Companies requested any relief for Grid Edge as part of this proceeding?

A. Yes. The Direct Testimony of Company witnesses Timothy J. Duff and Jonathan L. Byrd filed on September 1, 2023, and Exhibit 1 of the Supplemental Direct testimony of Company witness Kendal Bowman filed with the SPA contain two Requests for Relief specific to Grid Edge: (1) that the Commission allow the Companies to use 1% of eligible load annual EE savings as the annual floor or minimum load modifier for the CPIRP modeling; and (2) that the Commission find and conclude that the Companies' plan to continue advancing their Grid Edge and customer programs is reasonable and appropriate.

Q. Please respond to these two requests for relief.

A. With regard to the Companies' request that the Commission allow the Companies to use 1% of eligible load annual EE savings as the annual floor or minimum load modifier for the CPIRP modeling, it is appropriate to continue to apply and pursue EE savings associated with the modeling assumption of 1% of prior year eligible retail sales in the CPIRP. Continuing the use of this modeling assumption has become even more important now that the Commission has approved a tiered utility incentive structure as part of the recently concluded Mechanism review, which correlates the Companies' DSM/EE rider incentive to the achievement of prior year eligible retail sales in each annual proceeding going forward. The continuation of this modeling assumption should play a key role in advancing the pursuit of EE savings by the Companies.

With regard to the Companies' request that the Commission find and conclude that the Companies' plan to continue advancing their Grid Edge and customer programs is reasonable and appropriate, the Companies were granted a performance incentive mechanism in their most recently concluded general rate cases to incentivize rate designs that encourage demand and energy savings. Additionally, the Companies will be updating the value of those energy and demand savings, as well as proposing new customer incentive offerings, as a result of the Mechanism revisions. Therefore, I have high expectations that the Companies will propose more offerings related to Grid Edge and other customer programs prior to Duke's next CPIRP filing in 2025.

Q. Should the Companies' Requests for Relief with respect to the two Grid Edge topics discussed above be granted in this proceeding?

A. Yes. I recommend that the two requests for relief related to Grid Edge be granted for the purposes of this proceeding.

III. BILL IMPACTS

Q. Please describe how the Companies calculated the bill impacts in this CPIRP proceeding.

A. The Companies performed an analysis that illustrates the projected increases in an average residential customer's bill from 2023 through 2038. This analysis is inclusive of the Companies' North Carolina and South Carolina service territories. Unlike a billing analysis performed in a general rate case proceeding, this analysis is only focused on the incremental costs of the capital investments for constructing and interconnecting generation facilities to comply with HB 951, meaning that the bill impacts portrayed in this CPIRP do not include any costs related to distribution or other non-CPIRP capital investments that would be incorporated into a general rate case proceeding.

Additionally, the Companies have applied to all four jurisdictions the cost allocations in the Cost-of-Service Study (COSS) that is approved for each respective service territory by this Commission and the Public Service Commission of South Carolina. The COSS shows how the Companies allocate the costs of the individual generation and transmission assets going online in each year of the planning horizon and how the revenue requirements would change each year. The review and adoption of a CPIRP is not a rate setting exercise, nor is it a forum to review or modify the methodologies to apportion revenue requirements. The appropriate forum to address apportionment principles, such as addressing cross subsidy or rate shock issues, is within a general rate case. Instead, for purposes of planning, the Companies strictly adhered to the COSS allocations when determining how customer bills would increase year over year.

Once the average residential bill was determined for each jurisdiction, the Companies applied a weighted average allocation to arrive at a total system[4] average residential bill for both DEC and DEP. The Companies also performed a combined bill impact analysis, which analyzed average rate changes when DEC-NC, DEC-SC, DEP-NC, and DEP-SC are all combined.

Q. Does the Companies' bill impact analysis include new rate base from the recently concluded general rate cases?

A. No, it does not. To determine the average bill for each jurisdiction, the Companies used the rates, including riders, effective as of January 1, 2023. Through discovery, the Public Staff learned that the Companies perform a bill impact analysis twice a year (January and July), and that at the time of the original filing, the January 2023 analysis was the most currently available data.

Q. Did the Companies update baseline average bill assumptions in their SPA?

A. No. Despite updating many other assumptions in the SPA, the Companies failed to update baseline average bill assumptions. This results in a significant misrepresentation of the projected CPIRP bill impacts for the Companies' customers in light of the substantial multi-year rate case increases and annual rider proceeding updates

[4] This includes North Carolina and South Carolina.

recently approved in the Companies' North Carolina and South Carolina service territories.

However, through discovery, the Public Staff obtained an updated bill impact analysis from the Companies that reflects the projected capital investment changes in the SPA. These updated baseline average bill assumptions are incorporated within Figures 7 and 8 below and my exhibits, marked as Williamson Exhibits 5 and 6.

Q. Please elaborate on the difference between the baseline average bills for both DEC and DEP.

A. Below are the average residential bills for DEC's and DEP's North Carolina and South Carolina service territories combined to determine the starting point for the bill impact analyses. These values include the applicable annual rider charges as of the date of the selected baseline. Table 3 below reflects the Companies' application of a baseline average bill based on the rates in effect as of January 1, 2023, as well as the Public Staff's application of a baseline average bill based on the rates in effect as of February 1, 2024.[5]

[5] The average customer's residential bill for all four jurisdictions as of February 1, 2024, are as follows: DEC-NC: $ 142.12; DEC-SC: $138.93; DEP-NC: $156.47; DEP-SC: $152.74.

Table 3: Baseline Average Residential Customer Bills
(Combined NC and SC)

Rates in effect as of	DEC	DEP
January 1, 2023	$119	$136
February 1, 2024	$141	$156

Q. Should a bill impact analysis include the Companies' most recently approved rates and all known rate changes?

A. Yes. A full and accurate projection of a customer's bill increase attributable to the CPIRP must begin with the rates that customers are currently paying. While the incremental revenue requirement is not impacted by the starting point in a billing analysis, the bill impacts provided in the SPA are misleadingly low. In future CPIRP proceedings, I recommend that the Commission require that the Companies include all known and approved rate changes in their initial bill impact analysis, including updated bill impacts in any update filings similar to the SPA filed in this proceeding.

Q. What are the bill impacts as filed by Duke?

A. As part of the SPA, the Companies provided Figure SPA 1-3 in "Chapter 3: Supplemental Planning Analysis." Figure SPA 1-3 illustrated the changes in customer bills for years 2033 and 2038 for DEC, DEP, and both utilities combined. This figure reflects the capital investments associated with the Companies' recommended P3 Base and P3 Fall Base portfolios.

Q. Did the Public Staff evaluate the bill impacts associated with its recommended portfolio?

A. Yes. While the details regarding the selection of a particular generation resource are discussed in greater detail in the testimonies of Public Staff witnesses Thomas and Dustin R. Metz, I briefly discuss below the differences between the bill impact analyses of three portfolios. The average bills discussed below include, as a baseline, the impacts associated with the Companies' most recently concluded general rate cases and riders that were in effect as of February 1, 2024.

Q. Did the Public Staff evaluate the bill impacts associated with other portfolios?

A. Yes. During the discovery process, the Companies provided the modeling for the projected bill impacts associated with the Companies' P2 Fall Supplemental portfolio, which also reflects the load requirements described in the Companies' SPA.

Q. How does the bill impact of the other portfolios compare to P3 Fall Base?

A. Figures 7 and 8, below, are two graphical illustrations of the projected bill impact forecasts of the Companies' P3 Fall Base, the Companies' P2 Fall Supplemental, and the Public Staff's PS Base 2034.

Figure 7: DEC's Projected Bill Impacts by Portfolio

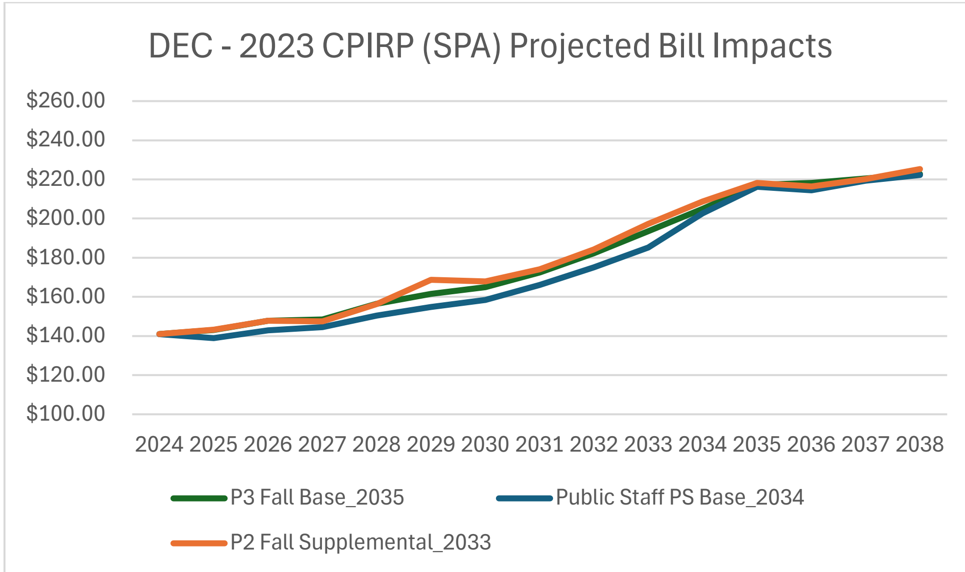
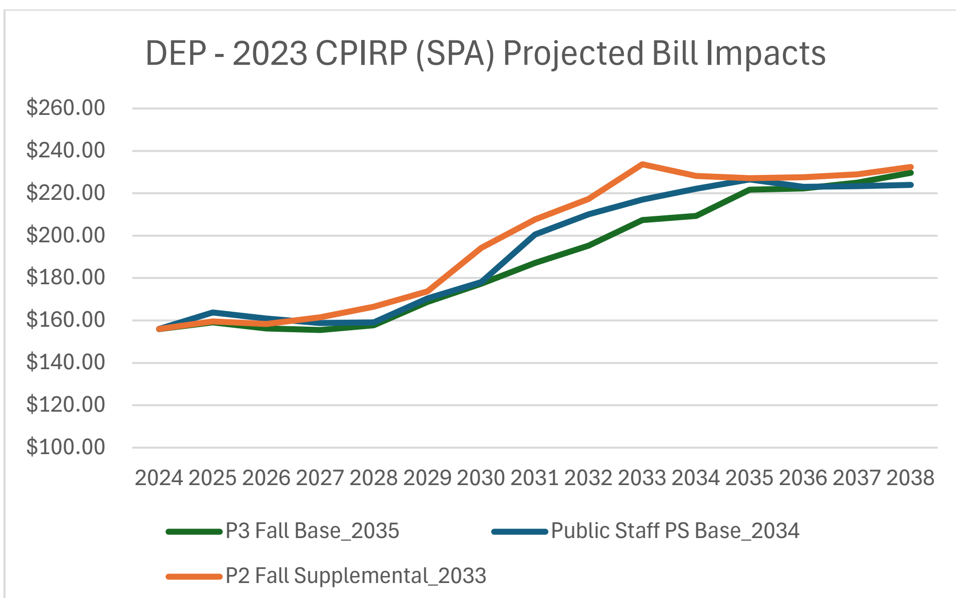


Figure 8: DEP's Projected Bill Impacts by Portfolio



Williamson Exhibits 5 and 6 include these graphs with additional details for each portfolio on an annual basis.

Q. Why is the Public Staff including a bill impact analysis for the P2 Fall Supplemental portfolio when the Companies are not recommending that portfolio for implementation?

A. The Public Staff believes that it is informative to see a variety of forecasts that achieve the 70% carbon emission reduction target in a particular year. The P2 Fall Supplemental portfolio assumes an interim compliance year of 2033, while the Public Staff's proposed portfolio assumes an interim compliance year of 2034. The Companies' recommended P3 Fall Base as represented in the SPA achieves interim compliance in 2035.

Q. Please elaborate further on what the three bill impact analyses are showing.

A. As discussed in greater detail in the testimonies of Public Staff witnesses Thomas and Metz, the three portfolios (P3 Fall Base, P2 Fall Supplemental, and PS Base 2034) analyzed by the Public Staff take different approaches toward achieving interim compliance in terms of the mix of generation units being selected and when those units would need to come online.

With respect to DEC, as compared to P2 Fall Supplemental, P3 Fall Base includes, among other things, an increased amount of solar and solar plus storage, and an earlier deployment date for onshore wind (2033 vs. 2035). Alternately, PS Base 2034 as compared to DEC's P3 Fall Base includes, among other things, increased solar plus storage, earlier deployment of onshore wind (2033 vs. 2035), less nuclear, fewer combustion turbines, and more combined cycles.

With respect to DEP, P3 Fall Base as compared to P2 Fall Supplemental includes, among other things, earlier deployment of offshore wind (spread over three years vs. all-in-one year) and increased solar plus storage. PS Base 2034 as compared to DEP's P3 Fall Base includes, among other things, removing combined cycles, adding combustion turbines and nuclear, increased amounts of solar plus storage, and an earlier and larger deployment of offshore wind.

Q. How should the Commission use this information on the three bill impact analyses?

A. This information provides the Commission with a visual diagram of the potential costs of complying with HB 951's interim compliance target earlier than what Duke has proposed as part of its P3 Fall Base. In the short term, the three portfolios all show a similar level of bill impacts through 2030. However, after 2030, all portfolios follow different generation build-out pathways, thus presenting a divergence of bill impacts.

I recommend that the Commission use this information in its assessment of customer impacts of differing interim compliance dates, feasibility, and reliability issues associated with given portfolios, and the overall costs to customers.

Q. Does this conclude your testimony?

A. Yes.

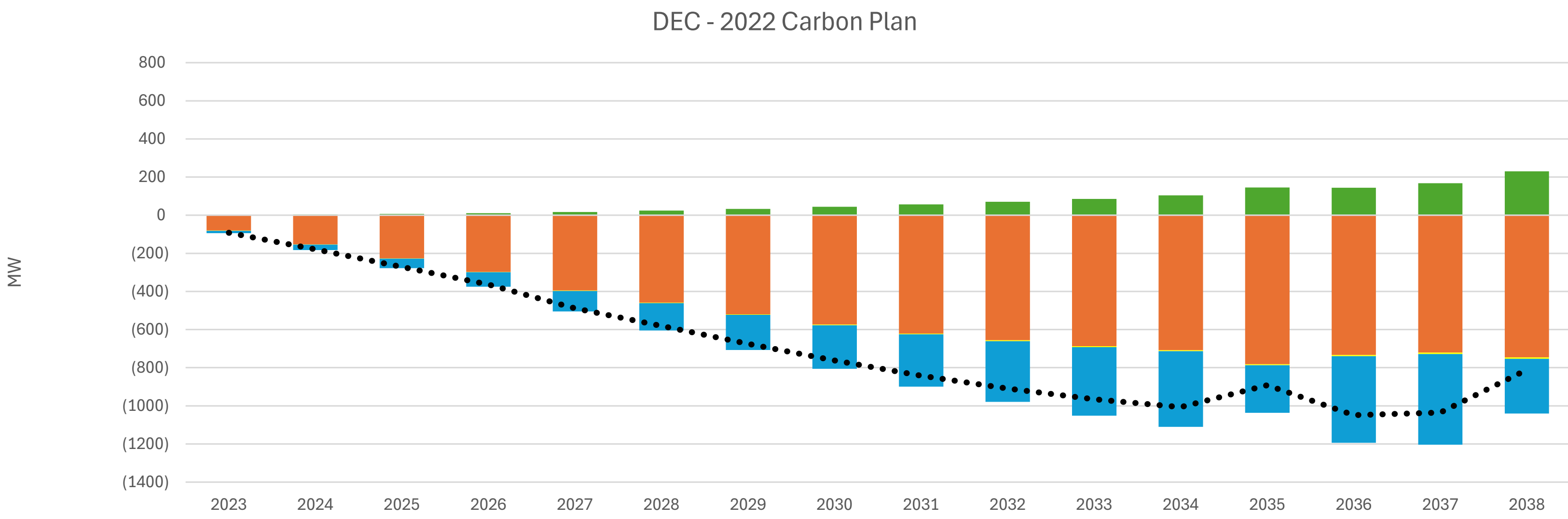
APPENDIX A

QUALIFICATIONS AND EXPERIENCE

DAVID M. WILLIAMSON

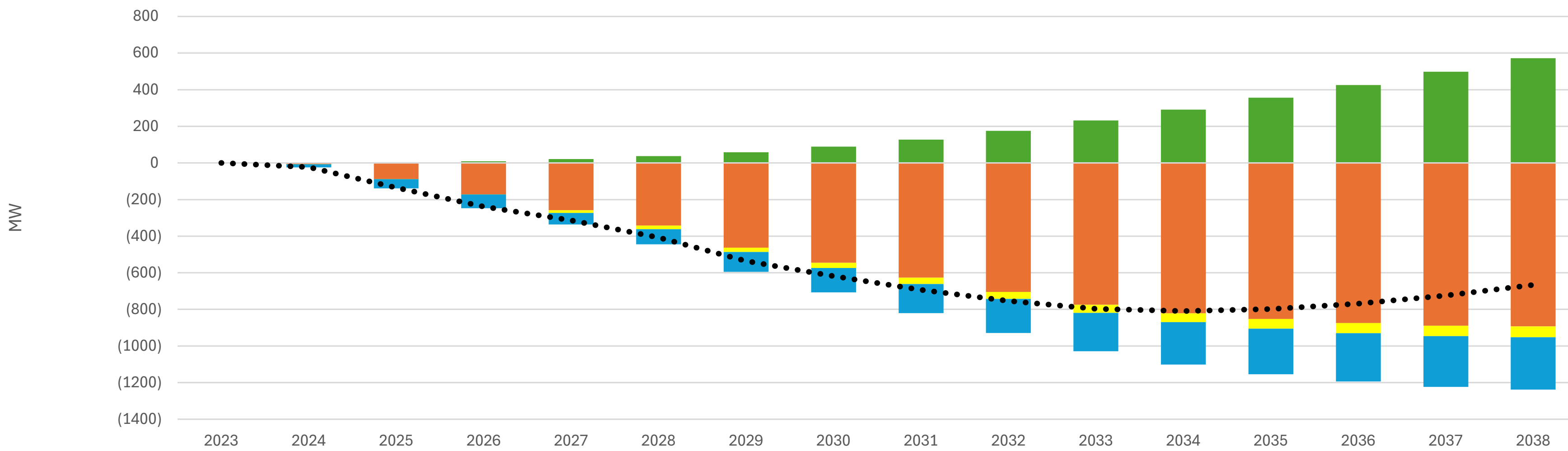
I am a 2014 graduate of North Carolina State University with a Bachelor of Science Degree in Electrical Engineering. I began my employment with the Public Staff's Electric Division in March of 2015. In August of 2020, the Electric Division merged with the Natural Gas Division to form the Energy Division, where I am a part of the Electric Section – Rates and Energy Services. My current responsibilities include reviewing applications; making recommendations for certificates of public convenience and necessity of small power producers, master meters, and resale of electric service; and interpreting and applying utility service rules and regulations.

My primary responsibilities within the Public Staff are reviewing and making recommendations related to new rate design proposals, application of cost-of-service studies, and the cost recovery and program performance of DSM/EE filings for Electric Investor-Owned Utilities. I have filed testimony in recent Electric and Natural Gas general rate case proceedings, as well as in various Demand-Side Management/Energy Efficiency rider proceedings for Duke Energy Carolinas, LLC; Duke Energy Progress, LLC; and Dominion Energy North Carolina.



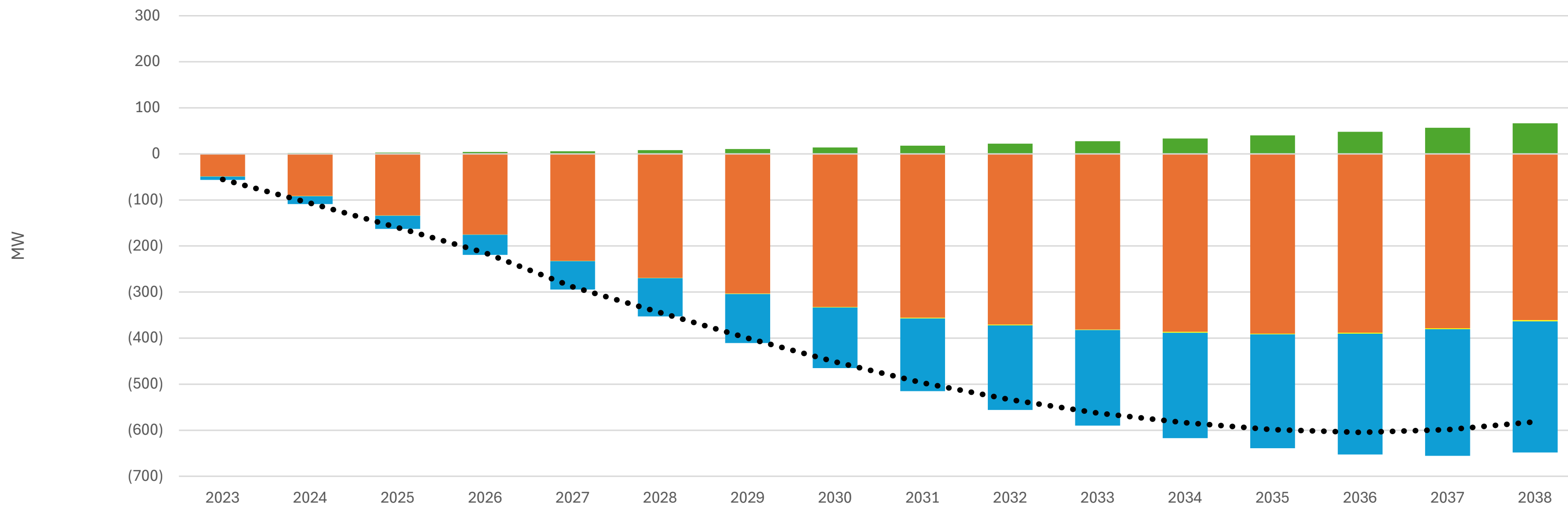
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Electric Vehicles	2	4	7	11	16	24	33	44	56	70	86	103	146	144	168	230
Rate Design	(13)	(29)	(50)	(76)	(107)	(144)	(185)	(229)	(274)	(318)	(359)	(396)	(249)	(454)	(475)	(287)
Rooftop Solar	(1)	(1)	(1)	(2)	(2)	(3)	(3)	(3)	(4)	(4)	(5)	(6)	(6)	(7)	(7)	(8)
EE	(81)	(153)	(227)	(297)	(396)	(459)	(520)	(574)	(621)	(656)	(686)	(708)	(781)	(733)	(721)	(745)
Net Impact	(92)	(179)	(271)	(364)	(488)	(581)	(674)	(762)	(842)	(909)	(965)	(1006)	(891)	(1049)	(1035)	(810)

DEC - 2023 CPIRP (SPA)



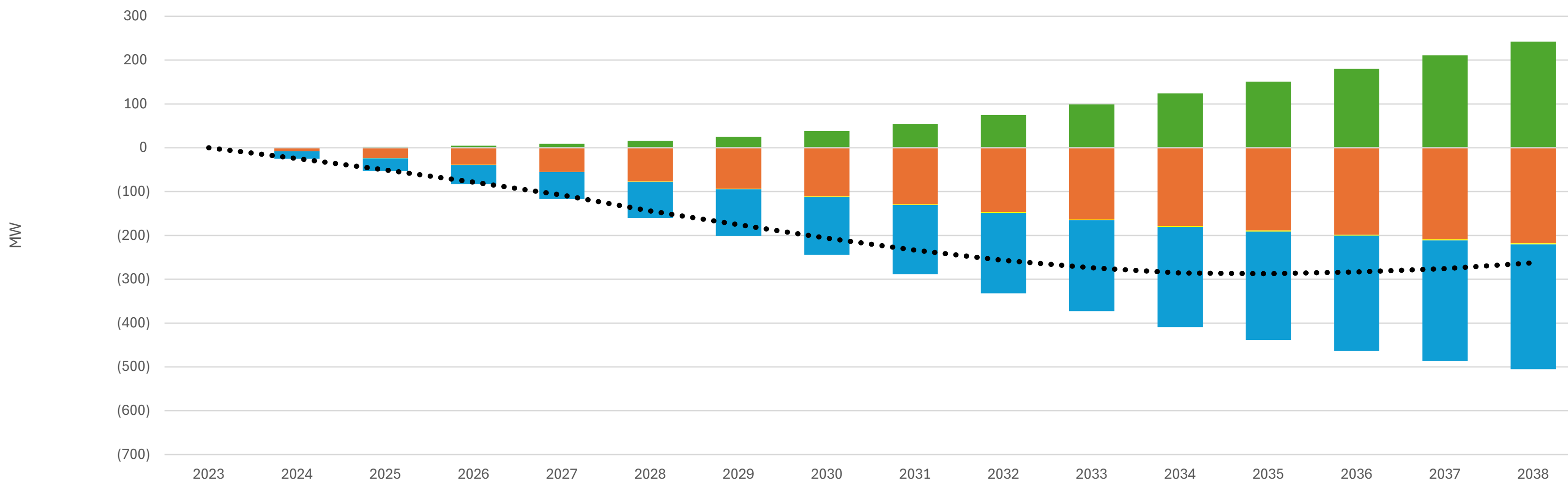
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Electric Vehicles		1	4	9	21	37	59	89	127	175	232	292	356	425	498	572
Rate Design		(17)	(50)	(76)	(62)	(84)	(108)	(133)	(160)	(185)	(210)	(231)	(249)	(265)	(277)	(287)
Rooftop Solar		(0)	(0)	(0)	(14)	(19)	(23)	(28)	(33)	(39)	(44)	(49)	(53)	(55)	(57)	(59)
EE		(7)	(89)	(172)	(259)	(343)	(463)	(545)	(627)	(705)	(775)	(821)	(853)	(875)	(889)	(893)
Net Impact	0	(24)	(135)	(239)	(314)	(408)	(536)	(618)	(693)	(753)	(797)	(809)	(799)	(769)	(725)	(666)

DEP - 2022 Carbon Plan



	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Electric Vehicles	1	2	3	4	6	8	11	14	18	22	27	34	40	48	57	67
Rate Design	(7)	(17)	(29)	(44)	(62)	(83)	(106)	(132)	(158)	(184)	(207)	(229)	(247)	(263)	(275)	(285)
Rooftop Solar	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(2)
EE	(49)	(92)	(134)	(175)	(232)	(269)	(303)	(332)	(356)	(371)	(381)	(387)	(390)	(388)	(379)	(361)
Net Impact	(55)	(107)	(160)	(215)	(289)	(345)	(400)	(451)	(497)	(534)	(563)	(584)	(599)	(605)	(599)	(582)

DEP - 2023 CPIRP (SPA)



	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Electric Vehicles		0	2	5	9	16	25	38	55	75	99	124	151	180	211	242
Rate Design		(17)	(29)	(44)	(62)	(83)	(106)	(132)	(158)	(184)	(207)	(229)	(247)	(263)	(275)	(285)
Rooftop Solar		(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
EE		(8)	(24)	(39)	(55)	(77)	(94)	(111)	(129)	(147)	(164)	(179)	(189)	(199)	(209)	(218)
Net Impact	0	(25)	(51)	(78)	(108)	(145)	(176)	(206)	(234)	(257)	(274)	(286)	(287)	(283)	(276)	(263)

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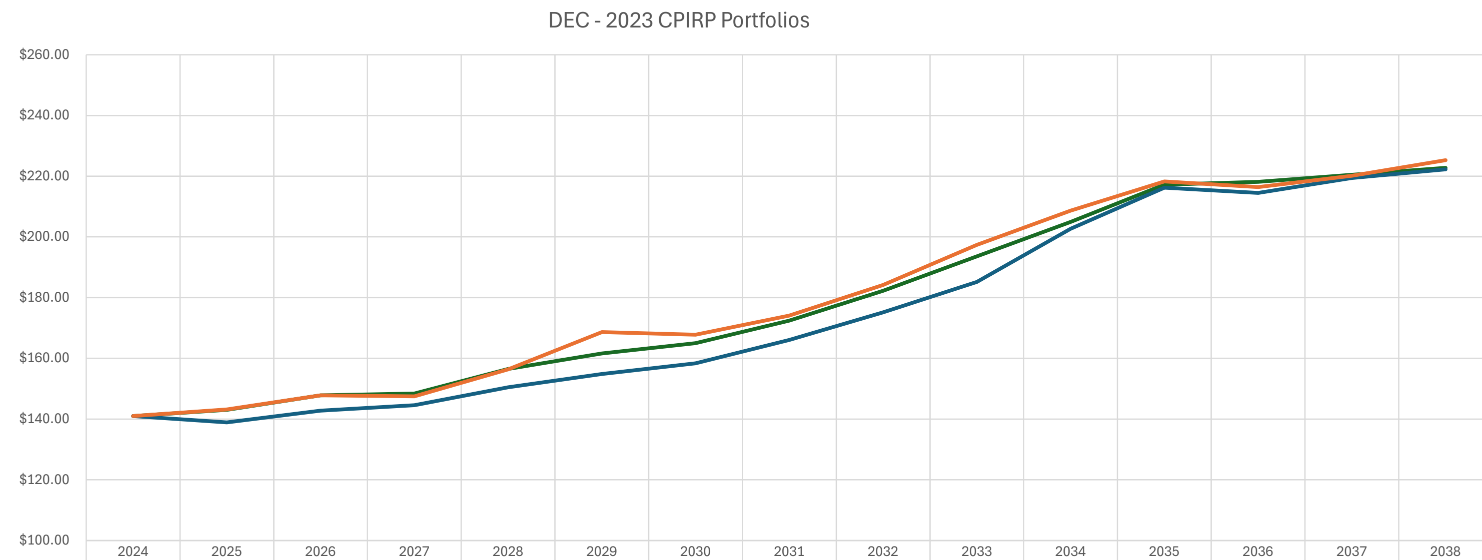

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
P3 Fall Base_2035	$141.00	$143.04	$147.84	$148.43	$156.53	$161.59	$165.02	$172.41	$182.25	$193.60	$204.96	$217.24	$218.14	$220.49	$222.75
Public Staff PS Base_2034	$141.00	$138.91	$142.81	$144.60	$150.47	$154.89	$158.40	$166.08	$175.14	$185.16	$202.69	$216.22	$214.47	$219.42	$222.26
P2 Fall Supplemental_2033	$141.00	$143.20	$147.85	$147.48	$156.36	$168.65	$167.82	$174.08	$184.17	$197.36	$208.68	$218.27	$216.41	$220.12	$225.28

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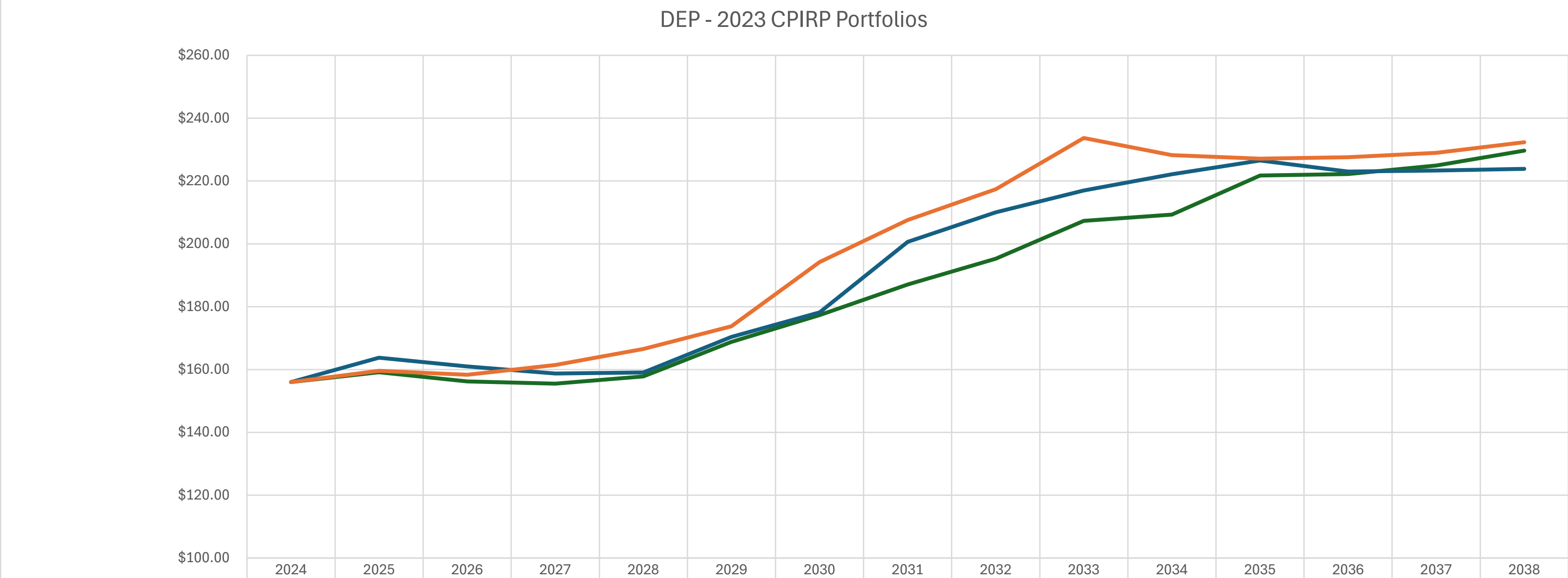

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
P3 Fall Base_2035	$156.00	$159.12	$156.23	$155.51	$157.79	$168.82	$177.32	$187.10	$195.30	$207.30	$209.33	$221.73	$222.24	$224.94	$229.68
Public Staff PS Base_2034	$156.00	$163.75	$160.97	$158.74	$159.09	$170.41	$178.18	$200.65	$210.02	$217.00	$222.17	$226.53	$223.03	$223.32	$223.89
P2 Fall Supplemental_2033	$156.00	$159.61	$158.33	$161.45	$166.55	$173.75	$194.19	$207.60	$217.35	$233.69	$228.21	$227.14	$227.56	$228.99	$232.33