NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

May 28, 2024

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

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

Dear Ms. Dunston:

Attached for filing on behalf of the Public Staff in the above-referenced docket is the public version of the testimony and exhibits of Evan D. Lawrence, Engineer with the Energy Division of the Public Staff – North Carolina Utilities Commission.

By copy of this letter, I am forwarding a copy of the redacted version to all parties of record by electronic delivery. Confidential information is located on pages 13, 24-26, 35, and 38-39 of the testimony and Exhibit 1 is confidential in its entirety. The confidential version will be provided to those parties that have entered into a confidentiality agreement.

Sincerely,

Electronically submitted
/s/ Lucy E. Edmondson
Chief Counsel
lucy.edmondson@psncuc.nc.gov

/s/ Nadia L. Luhr
Staff Attorney
nadia.luhr@psncuc.nc.gov

Attachments

CERTIFICATE OF SERVICE

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

This the 28th day of May, 2024.

Electronically submitted
/s/Nadia L. Luhr

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 190

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

MAY 28, 2024

Q. Mr. Lawrence, please state your name, business address, and current position.

A. My name is Evan D. Lawrence. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina, where I work for the Public Staff - North Carolina Utilities Commission (Public Staff). Within the Public Staff, I am an engineer in the Energy Division, specifically the Electric Section – Operations and Planning.

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 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 testimony in this proceeding?

A. The purpose of my testimony is to provide the Commission with the results of my investigation and recommendations pertaining to electric vehicle load impacts and onshore and offshore wind energy generating resources in the consolidated 2023 Carbon Plan and Integrated Resource Plan (CPIRP) filed by Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP) (together, Duke or the Companies), in this docket on August 17, 2023, as well as the supporting direct testimony filed on September 1, 2023. My testimony also addresses the Supplemental Planning Analysis (SPA) and supporting testimony filed on January 31, 2024, resulting from significant increases in Duke's electric load forecast.

Q. Please describe the scope of your investigation.

A. My investigation into the Companies' electric vehicle (EV) load forecast involved an evaluation of the hourly EV load forecast through the planning horizon, along with the variables that informed those projections. In addition, I evaluated the EnCompass modeling inputs for wind energy (both onshore and offshore) and evaluated the development timelines. To accomplish these tasks, I reviewed the Companies' testimony, responses to Public Staff and other intervenor data requests, and publicly available data. In addition, I participated in multiple conference calls and meetings with the Companies and other intervenors, including the leaseholders of offshore wind areas, in this proceeding.

Q. Please summarize the results of your investigation and your recommendations.

A. My investigation resulted in the following key findings and recommendations:

1. The Companies' EV load forecast is adequate for planning purposes in this docket. The EV load forecast filed in the January 31, 2024 SPA incorporates changes that I believe more accurately convey the actual load to be expected at this point in time.

2. After the Companies filed their SPA, the United States Environmental Protection Agency (EPA) finalized automobile emission standards in March 2024, as described in more detail later in my testimony. My initial impression from this new standard is that it will likely require more rapid EV deployment and generation of requisite electric load.

3. While there is limited development potential for onshore wind energy within the Companies' service territories, the EnCompass modeling completed by the Public Staff indicates that onshore wind energy is being selected as an economic resource across all

modeled scenarios, subject to the Companies' modeling assumptions. As such, the Companies should take steps toward appropriate joint development with ratepayer protections and risk management, and diligently work to ensure that development of each individual site is the most prudent path forward.

4. Nearly every Public Staff EnCompass modeling scenario indicates that at least 2,200 MW of offshore wind is needed between 2031 and 2034, with portfolio selections ranging between 1,100 MW and 4,400 MW. While some of the Public Staff's EnCompass modeling suggests that offshore wind could help meet the Companies' energy demand requirements as early as 2031, it is unlikely to become available before 2034-2035. The ability to procure offshore wind in these amounts and within these timeframes depends largely on uncertain timelines for project development and transmission infrastructure construction.

5. I recommend the Commission direct the Companies to issue a modified Acquisition Request for Information (ARFI) on a timeline that ensures the results will be meaningfully incorporated into the Companies' next CPIRP filing. I further recommend that the Companies promptly file the ARFI results with the Commission so that the Commission can timely determine what appropriate next steps should be taken by the Companies, if any, resulting from

decisions made in this proceeding regarding offshore wind. The Commission also should order the Companies to proceed with the recommendations listed in Public Staff witness Metz's near-term action plan (NTAP).

Q. How is your testimony organized?

A. My testimony is organized into four sections as follows:

I. EV Load Forecast
II. Onshore Wind Energy
III. Offshore Wind Energy
IV. Findings and Recommendations

Q. Are you providing any exhibits with your testimony?

A. Yes. I am including one exhibit, described below.

Confidential Lawrence Exhibit 1. DNV Onshore Wind Site Potential Maps

I. <u>EV Load Forecast</u>

Q. Please provide an overview of your investigation regarding the Companies' EV load forecast.

A. My evaluation of the Companies' EV load forecast consisted of a review of the Companies' data responses, testimony, and CPIRP; and information from publicly available sources, including the North Carolina Department of Transportation's (NCDOT) vehicle registration data. I have shared my findings with Public Staff witnesses Bob Hinton and Patrick Fahey (Load Forecast Panel), David Williamson, and Jeff Thomas for incorporation into their investigations, EnCompass modeling, and testimonies.

Duke's EV load forecast includes energy consumption from zero emissions vehicles (ZEVs), which are inclusive of both EVs and plug-in hybrid electric vehicles (PHEVs). While the EV load forecast is driven primarily by EVs, PHEVs also contribute to load growth to a lesser extent. Additionally, the load growth for ZEVs is attributed to greater adoption patterns, as opposed to changes in technology or driving behaviors. I find the Companies' forecasts to be acceptable for planning purposes.

Q. Please discuss how the electric vehicle load forecast was developed.

A. Appendix D of the Companies' initial filing discusses how this forecast was created. To develop the EV load forecast, the Companies used both Guidehouse[1] and the Vehicle Analytics and Simulation Tool (VAST)[2] in the same manner as they were used in

[1] Guidehouse is a consulting firm that assists businesses and industry with, among other things, data-driven market research and domain expertise related to EV adoption.

[2] Vehicle analytics and simulation tools help reduce testing time and cost by accurately representing the vehicle being simulated, as well as supporting the development and optimization of vehicle characteristics and driving behavior from initial concept to test phase.

the 2022 Carbon Plan proceeding.[3] The Companies use data from various sources to provide the VAST with the necessary inputs. These inputs include vehicle registrations, EV adoption rates, vehicle efficiency, vehicle usage characteristics, applicable rate schedules, and vehicle charging characteristics. The VAST compiles this data and creates an hourly load profile that is then scaled based on the number of vehicles in operation.

Q. You indicated previously that you evaluated the EV load forecast. Please discuss your evaluation in more detail.

A. My evaluation consisted of verification of the characteristics that I discussed previously that flow into the VAST. I reviewed publicly available information as a benchmark to determine whether the modeling inputs were reasonable. For instance, to evaluate the number of vehicle registrations, I used the NCDOT published registrations[4] and selected the counties served by DEC and DEP, respectively. The county-level data provides a reasonable proxy for comparison purposes, recognizing that each utility's service territory does not strictly align with individual county boundaries and that other electric utilities have a portion of total EV customers in a given county. Nevertheless, I worked under the assumption that the

[3] Docket No. E-100, Sub 179.

[4] https://www.ncdot.gov/initiatives-policies/environmental/climate-change/Pages/plan.aspx

majority of EVs in a given county are within the DEC and DEP service territories, as DEC and DEP serve a significant percentage of the customers in many of the counties where they provide service, noting that there are exceptions to this generalization.

Q. Please discuss the recently finalized EPA vehicle emissions standards.

A. On March 20, 2024, the EPA finalized its Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles (Vehicle Emissions Standards) that aim to reduce tailpipe emissions, including greenhouse gases such as carbon dioxide.[5] Based on my initial review, I believe this standard will likely have upward pressure on the sales, and overall penetration, of EVs across the country, with an accompanying increase in energy and demand. This standard begins a phased approach beginning with 2027 model year vehicles. At this time, the overall magnitude of the impact to the Companies' EV load forecast by the Vehicle Emissions Standard is unclear. The Public Staff has not modeled its potential impact on the CPIRP. I request that the Companies address this topic in rebuttal testimony to the extent that they are able to do so. I further recommend that the Companies specifically discuss this

---

[5] *See* https://www.epa.gov/regulations-emissions-vehicles-and-engines/final-rule-multi-pollutant-emissions-standards-model

topic, and make appropriate adjustments to their EV load forecast, in the 2025 CPIRP filing.

Q. How did the Companies adjust their EV load forecast in the SPA?

A. In their SPA, the Companies utilized the same VAST software and the same source data as in the initial filing (i.e., the way the inputs were considered remained the same), but they did refresh the input data and make two methodological changes. These changes were mostly immaterial to energy demand (MWh) in the near term but did have an impact on winter peak demand (MW). The changes made in the SPA that I believe are driving these impacts are described below.

The first change related to vehicle efficiency. The vehicle efficiency input that was used in the initial filing was determined by taking the average efficiency of available vehicles and making a minor adjustment to account for the actual vehicles purchased. However, in the SPA, the updated vehicle efficiency input was determined by using a weighted average efficiency.

In their initial filing, the Companies' vehicle efficiency calculation weighted each of the available vehicles equally; however, this analysis is not representative of the real-world impacts of EVs. In the SPA, Duke modified the weighting based on the efficiency of the number of vehicles sold. Because higher efficiency vehicles have been much more popular, the overall weighted efficiency increased, thus reducing energy consumption per vehicle.[6] The immaterial change to EV energy demand through 2038 in the SPA is likely because the reduced energy consumption per vehicle was outweighed by a higher number of vehicles deployed.

The second change the Companies made was to further incorporate the impacts of time-of-use (TOU) rate schedules on EV adoption and charging patterns. In the initial filing, the general load shape modeled gave consideration to some customers being on TOU schedules, but this was a passive result. In the SPA, a larger weighting was given to EVs served on TOU schedules, resulting in an active load shift away from peak times, especially in the 2030s. This effect was particularly pronounced in DEC, which saw its winter peak load impact from EVs decline by more than 10% throughout the planning period. To ensure that the Companies' SPA EV load forecast remains accurate over the planning period, the Companies will need to continue their efforts to promote TOU rates for EV customers, and to perhaps develop new EV-specific TOU-based rate designs.

---

[6] For instance, Tesla delivered 1,739,707 Model 3 and Model Y vehicles combined in 2023. The Model 3 has a rating of 132 miles per gallon equivalent[6] (MPGe) and the Model Y is rated for 122 MPGe. During 2023, Ford delivered 40,771 Mustang Mach-E vehicles, which have a rating of 82 MPGe to 103 MPGe[6] depending on the trim package selected. By weighting the vehicle efficiency by sales in the SPA, the weighted average efficiency would be closer to a Tesla Model 3 or Model Y than a Ford Mustang Mach-E. MPGe data was derived from https://fueleconomy.gov/.

Q. Do you agree with the EV load forecasting changes made in the SPA?

A. I do. I believe that the changes the Companies made to their EV load forecast are reasonable and appropriate, and that the updated load forecast is more representative of real-world expectations than what was reflected in the initial filing. Had the Companies not proposed these modifications to the supplemental load forecast, I would have recommended that they take steps to implement these changes in this CPIRP proceeding.

Q. Please discuss how the changes in the SPA impact the Companies' EV load forecast.

A. Compared to the initial load forecast, the supplemental EV load forecast load shape[7] shifted energy usage away from peak periods, and into non-peak periods, largely reducing the total energy consumed during peak periods over the next 10-15 years, despite an increase in the overall number of projected EVs. Figure 1 below shows this relationship during the summer season in 2035. However, after this initial period, the number of EVs is projected to increase to a point where the load shift from TOU rates and the increase in

[7] A shift in load shape points to managed charging to avoid charging only during peak periods. It is representative of a higher load factor, which has a direct correlation to how efficiently the grid is being used to meet the EV charging loads.

vehicle efficiency no longer result in a decrease to the peak load when compared to the initial load forecast.

Figure 1: EV Load Shape Comparison

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Do you believe that there are any areas pertaining to the EV load forecast used in the SPA that need to be improved?

A. Not for this proceeding. As stated above, I believe the SPA EV load forecast is sufficient for planning purposes. However, I encourage the Companies to continue to study EV loads as well as any techniques that will help moderate impacts to the system. EVs represent a unique load in the way that the load can be shifted. Unlike other demand-shifting options that may be able to shift demand by a couple of hours, EV load can potentially be shifted throughout the day.

Q. Do you have any recommendations for the Commission related to the EV load forecast?

A. I recommend that the Commission accept for planning purposes the Companies' EV load forecast, as presented in the supplemental filing.

The Companies should continue to monitor and adjust EV load forecasts in future CPIRPs, and the Companies' upcoming 2025 CPIRP should account for the EPA's Vehicle Emissions Standards with heightened attention on the impacts of medium and heavy-duty vehicles on the load forecast.

I also recommend that the Commission direct Duke to continue to investigate and propose appropriate rate tariffs and other customer programs that can aid in shifting EV demand away from peak periods, as reflected in the SPA EV forecast. As my analysis shows, should the Companies fail to manage EV demand, it can result in a larger impact to peak load than anticipated in this proceeding.

II. <u>Onshore Wind Energy</u>

Q. Does the Public Staff believe that the selection of onshore wind energy resources in the CPIRP is reasonable?

A. Yes. The EnCompass modeling conducted by the Public Staff resulted in the selection of onshore wind resources of varying amounts, depending upon which constraints were included. The Public Staff's modeling analysis resulted in the selection of anywhere from 1,350 MW to 2,100 MW of onshore wind to be in service by 2033. In addition, the selection of onshore wind is economic even without a carbon constraint imposed on the system. Duke submitted model runs without a carbon constraint in both its initial filing and SPA; in both cases, the Companies' model economically selected between 600 and 1,050 MW of onshore wind in the 2030s.

Q. Please discuss the onshore wind modeling inputs included in the EnCompass model by the Companies and the Public Staff.

A. For purposes of modeling its base portfolio, the Public Staff did not modify any onshore wind inputs or assumptions used by the Companies in their SPA. However, the Public Staff did perform a sensitivity analysis, in the form of a model run that modified the onshore wind output profile for both DEC and DEP based on a lower hub height, resulting in a lower capacity factor for onshore wind (a reduction of approximately 16.2% of the annual energy output for

DEC and 17.9% for DEP). In this particular sensitivity, the amounts of onshore wind economically selected by EnCompass were unchanged.

Q. Please provide a summary of the Companies' onshore wind changes from the initial filing to the SPA.

A. The Companies updated the modeling costs for onshore wind energy between the initial and updated filings to reflect more up-to-date cost and interest rate information that increased the capital cost of onshore wind by approximately 38% in 2031. However, the capital cost increase did not have an impact on the amount of onshore wind that was economically selected, and there was a minimal impact on the overall cost of implementation.

Q. Why did the Public Staff not modify the inputs for the base modeling despite completing a sensitivity analysis using a modified output profile?

A. Overall, given the increase in capital costs included in the SPA, the Public Staff believes the assumptions regarding onshore wind are generally reasonable for planning purposes. This sensitivity analysis was completed to see which resources would be needed to backstop onshore wind should the amounts selected by EnCompass not be procured, as well as to evaluate the risks associated with this relatively undeveloped resource in North and South Carolina when compared to other technologies like solar, batteries, and natural gas generation. I am concerned, however, that the capacity factors utilized are overstated, particularly DEP's 26.6%. In order to realize an onshore wind capacity factor of 26.6% in DEP, I believe numerous factors influencing the overall generation profile would need to be set at the upper end of reasonableness.

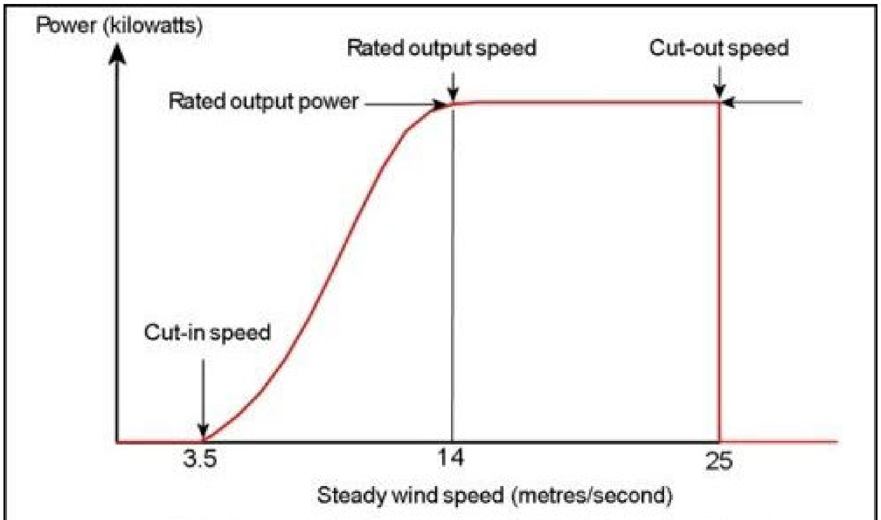
Q. Please elaborate on these factors and how they would impact the generation profile.

A. As with any electric generation system, components of a wind turbine can be modified to optimize a different characteristic, be it cost, energy output, weight, or overall efficiency. These characteristics can be broken down into two main categories for the purposes of this discussion.

The first category is the energy output of one turbine at a given wind speed, referred to as a "power curve." Manufacturers represent the power curve graphically. Figure 2 below shows an example power curve for a generic wind turbine.[8]

[8] https://theroundup.org/wind-turbine-power-curve/

Figure 2: Wind Turbine Power Curve Example.

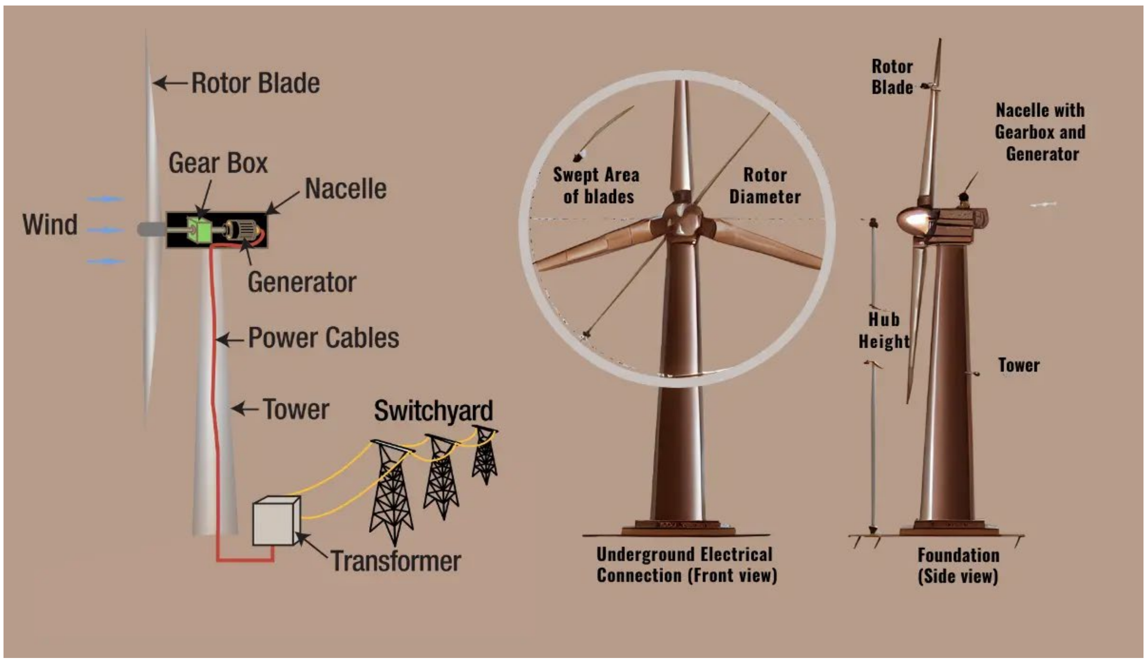


Typical wind turbine power output with steady wind speed.

In this example, the "cut-in" speed, which is the minimum speed required to produce electricity, is 3.5 m/s; the turbine reaches its maximum output at a wind speed of 14 m/s, and has a maximum operating wind speed of 25 m/s. Importantly, this graph shows the correlation between wind speed and power output; even between the cut-in speed and the lowest wind speed the turbine reaches, the maximum electrical generation output is not linear. Additionally, this graph shows that as long as the wind speed is above 14 m/s but below 25 m/s, there is no difference in power output (similarly, this is true for speeds below the cut-in wind speed).

The second category is the height of the turbine hub, the central part of the turbine to which the blades connect. In my Figure 3[9] I present a wind turbine diagram that shows, among other things, where the turbine hub height is measured.

Figure 3: Wind Turbine Diagram



Generally, wind speeds increase as height increases, so the higher the hub of the turbine, the more it is exposed to stronger, consistent winds. For modeling purposes, the Companies have assumed a 120-meter hub height. While a 120-meter hub height is not an unreasonable assumption, I question the likelihood of an average 120-meter hub height across all of Duke's territory coming to fruition

[9] https://windmillstech.com/schematic-diagram-of-wind-turbine/.

in the near term. An August 24, 2023 report from the U.S. Department of Energy Office of Energy Efficiency & Renewable Energy[10] indicated that the average height for installed turbines in the United States in 2022 was 98 meters. While this same report also reflects that the hub height for wind turbines has been steadily increasing across the US, I am not optimistic that the Companies will be able to deploy these taller turbines in the near future. In Table 1, I show the three most recent applications for onshore wind projects in North Carolina, along with each facility's turbine hub height. Public Staff witness Thomas spoke to the development of onshore wind energy in North Carolina in his testimony in the 2022 Carbon Plan proceeding.

Table 1: Onshore Wind Energy Facilities in North Carolina

Docket No.	Facility Name	Nameplate Capacity (MW_{AC})	Hub Height (meters)	CPCN Issuance Date
EMP-49, Sub 0	Atlantic Wind, LLC	300	~92	May 3, 2011
EMP-61, Sub 0	Pantego Wind LLC[11]	80	N/A	March 8, 2012
EMP-118, Sub 0	Timbermill Wind, LLC	189	~105	May 4, 2022

[10] https://www.energy.gov/eere/articles/wind-turbines-bigger-better.

[11] Construction on the Pantego Wind, LLC, facility has not yet started.

Q. You referenced a modified output profile for onshore wind modeling that you created. Please elaborate, including impacts of the modifications on the generation profile.

A. The Companies provided the onshore wind hourly output profiles (referred to as an 8760-output profile for the number of hours in a non-leap year) in response to discovery. I used these as the basis for my output profiles. I first created a proxy power curve to match the expected generation profile. I assumed that the wind speed used is the average wind speed provided in a wind siting analysis[12] completed by DNV Energy USA Inc. (DNV) for a 120 m hub height for each utility based on the interconnection location. Then, I took the 100 m hub height wind speeds for those same sites and determined the ratio of wind speeds between the two heights. Using that information, I was able to determine an expected wind speed for each hour of the 8760-output profile, and then apply those wind speeds to my proxy generation profile to create a new load profile. I believe this method appropriately captures the impact of the reduced hub height and the operational characteristics of the wind turbines. This modification resulted in an annual average capacity factor for DEP of 21.9% and 16.1% for DEC. By comparison, this is a reduction from Duke's assumptions of 26.6% for DEP and 19% for DEC.

[12] *See* CPIRP, Appendix I, at 20.

Q. Can you provide any insight on why the capacity factors used by the Companies are different between DEP and DEC and how that would impact modeling results?

A. From a review of the resource modeling assumptions in EnCompass, the onshore wind capacity factor and capacity value[13] is greater in DEP than in DEC. The wind energy potential at sites in DEC and DEP can be seen in the 120-meter hub height wind speed maps, attached as Confidential Lawrence Exhibit 1. Developing wind facilities in certain areas, such as in western NC, would likely be challenging due to local ordinances and laws such as the Mountain Ridge Protection Act of 1983, which imposes height restrictions on certain development. Based on my review of information provided by the Companies, absent larger developments in DEP's western North Carolina service areas, the average DEP wind resource would likely have a lower capacity value than modeled.

Q. What impact does this assumption have on modeling results?

A. Generally, Duke's SPA portfolios select the majority of onshore wind in DEP's territory. For example, P3 Fall Base sites 600 MW of onshore wind in DEC and 1,650 MW in DEP. It is reasonable to assume that the EnCompass model selects more resources in the DEP area given the differences in total energy produced and the

[13] The capacity value is the resource's expected contribution during peak events. This is described in more detail in witness Thomas' testimony.

higher contribution to the target reserve margin. All else being equal, when EnCompass is deciding between two resources with the same capital costs, but one produces more energy and capacity, it will select the more productive resource. Thus, the higher capacity factor and capacity value assigned to DEP onshore wind may be contributing to the model's preference for onshore wind located in DEP over DEC.

Q. How did the results of the model using your modified generation profile compare to the Public Staff's base case scenario?

A. The model with the modified generation profile for onshore wind still selected the same amount of onshore wind, and approximately the same timeline, as the Public Staff's base portfolio. The model with the modified generation profile for onshore wind still selected the same amount of onshore wind, and approximately the same timeline, as the Public Staff's base portfolio (PS Base 2034).

Q. What actions have the Companies taken for the development of onshore wind energy resources?

A. The Companies have worked with DNV to study and identify potentially feasible areas for onshore wind energy development in the Carolinas. This study was a comprehensive analysis of potential barriers to development, which informed the Companies of the most favorable locations to begin the site-specific analysis. This analysis was completed, in part, in response to the Commission's December 30, 2022 Order Adopting Initial Carbon Plan and Providing Additional Direction for Future Planning in Docket No. E-100, Sub 179. The Commission stated, in part:

> The Commission finds it reasonable to direct Duke to engage with onshore wind stakeholders and any others Duke finds are necessary to support its request that the Commission select onshore wind as part of its future preferred Carbon Plan portfolio as soon as practicable on the issues identified by the Public Staff. In formulating its first biennial CPIRP, Duke shall consider onshore wind and particularly any pertinent information gleaned from its stakeholder engagement, and, to the extent that future EnCompass modeling economically selects utility-owned onshore wind resources, Duke should support that proposal in detail in its first biennial CPIRP.

Q. Please discuss the results of that study.

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

[redacted] development are shown in Confidential Lawrence Exhibit 1, slide 20. **[END CONFIDENTIAL]**

Q. What is your assessment of the study completed by DNV?

A. I find that the study appropriately identifies potential onshore wind sites for development. My understanding is that the study was completed to identify potential sites, and not to serve as a definitive site selection algorithm. Many factors are likely to impact the ability to develop even the highest ranked sites identified in the study, including the willingness of local governments and individual landowners to work with the Companies to site onshore wind facilities

[14] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

in a particular jurisdiction or on their property. **[BEGIN CONFIDENTIAL]** While the Companies included some of these factors in their analysis, such as local permitting risks and proximity to military sites and training routes, site-specific analyses will inevitably reveal constraints not discovered during the high-level DNV analysis. **[END CONFIDENTIAL]**

Q. Your testimony indicates some level of apprehension towards the likelihood of the successful development of onshore wind in the Carolinas. What risks have you identified if the Companies are unable to procure the targeted amount?

A. As I stated previously, all the Companies' portfolios call for 2,250 MW of onshore wind by 2036, with the various portfolios only differing in the deployment timeline.[15] PS Base 2034 also calls for 2,250 MW by 2034. The maximum amount of onshore wind that the model was permitted to select was 2,250 MW.

These results demonstrate that onshore wind is needed to meet system energy and capacity needs and the carbon reduction targets imposed by HB 951. In the Public Staff's modeled scenarios where onshore wind was either limited or procured later, the quantity of selected onshore wind resources varies, but the resource is

[15] P1 Fall Supplemental selects 2,250 MW by 2033, while P3 Fall Base selects this amount by 2036.

consistently selected. However, the selection of onshore wind even in Duke's simulations without a carbon constraint suggests that onshore wind is part of a least-cost, no regrets plan. The consistent selection of onshore wind across every portfolio also suggests that if the Companies cannot procure onshore wind at the levels forecasted, then other more expensive resources may need to be procured to meet system needs.

Q. Please discuss what needs to happen to provide more certainty that onshore wind will be able to come online in the timeframe and amounts selected.

A. As previously stated, my two primary concerns each involve the procurement of land necessary to build the individual facilities. The Companies have indicated that obtaining site control is expected to begin mid-2024. They have also begun discussions with local governments in this regard. Obtaining land rights is a major hurdle that must be cleared before more serious planning can commence. After the land rights have been largely secured, the Companies will be able to install meteorological survey (met) towers to better assess the actual wind speeds at those locations, rather than relying on theoretical wind speed estimates. The data collected from the met towers will provide the information necessary to (1) site individual turbines, (2) determine the necessary hub height at that location, and

(3) give an accurate representation of the actual energy that a facility can produce.

My second concern regards the Companies' ability to get approval for wind turbines on land that is acquired or leased. While the Companies must ultimately have some stake in the land in order to develop the project, it is always possible that a project will not be approved due to a variety of factors. To address both concerns, the Companies should endeavor to enter into purchase or lease options where possible, when doing initial site exploration, in order to protect ratepayers from the risk that the Companies will purchase land that is not ultimately able to be used for onshore wind generation facilities.

Q. You spoke about necessary initial development activities for onshore wind. Please expand on these activities and discuss the development activities the Companies have included in their Amended Request for Relief.

A. The Companies request that the Commission authorize $65.6 million in development costs to complete the following activities: select an onshore wind development partner, perform site feasibility studies, begin activities associated with siting and development, and submit interconnection requests in the 2025 and 2026 interconnection studies. Limited development activities have taken place to date.

Figure I-4 of Appendix I of the initial filing shows an illustrative development timeline for a generic onshore wind project. The Companies state that in order to deploy 1,200 MW of onshore wind by 2033, with the first resources coming online in 2031, development activities must begin in 2024. The first major activity, obtaining site control, was expected to begin in the second quarter of 2024. The Companies' expectations are that they will be able to obtain the necessary site control to enter the first onshore wind projects into the 2025 interconnection study process. Should this not occur as currently planned, the project would likely be delayed by at least a full year. Further, as stated earlier, the Companies cannot install met towers until at least partial site control is obtained. If the met tower data is not as favorable as expected, the project design would need to be modified, potentially triggering a new interconnection study and further delays. I request that the Companies provide an updated timeline in rebuttal testimony.

Generally, for planning purposes, I do not take issue with the initial development activities outlined by the Companies for onshore wind, including those in the onshore wind Development Plan in Appendix I, Table I-4, even though those activities are not necessarily additional to the Companies' normal course of business. I generally concur with the scope of development activities and agree that their respective costs seem reasonable. I have provided this recommendation to Public Staff witnesses Boswell and Zhang, who also discuss the expected accounting treatment of those costs in their testimony.

Q. Do you support Duke's procurement of onshore wind based on the EnCompass modeling and your analysis?

A. I believe the continued development of onshore wind resources for future procurement is reasonable and part of a least-cost portfolio, given the information available at this time. Each site has unique characteristics, which may ultimately make one or more of them unreasonable to pursue. However, there are also risks to HB 951 compliance and ratepayers if onshore wind is not developed in the Companies' service territories. I recommend that the Companies acquire additional information that is more specific to the sites they have identified through the DNV study for use in the development of the next CPIRP filing.

III. Offshore Wind Energy

Q. Please discuss current offshore wind energy potential for the Companies.

A. Currently, there are four wind energy area (WEA) leases[16] that are under development off the coast of North Carolina, held by three leaseholders. I have summarized these WEAs in Table 2 below.

Table 2: Offshore Wind - WEAs

Leaseholder	BOEM Lease Number	WEA Name	Estimated Maximum Capacity
TotalEnergies Carolina Long Bay, LLC	OSC-A 0545	Carolina Long Bay (CLB) West	1000 MW$_{AC}$
Cinergy Corp.[17]	OSC-A 0546	CLB East	1300 MW$_{AC}$ **Error! Bookmark not defined.**
Avangrid Renewables, LLC	OSC-A 0508	Kitty Hawk South	2400 MW$_{AC}$
	OSC-A 0559	Kitty Hawk North	1100 MW$_{AC}$

Q. In Table 2, you list the "estimated" maximum capacity for each WEA. Why is this value estimated?

A. The final capacity of the lease areas is dependent on several factors. Avangrid Renewables, LLC (Avangrid), TotalEnergies Carolina Long

[16] There are four WEAs across two sites. More information can be found at the following link: https://www.boem.gov/renewable-energy/state-activities/north-carolina-activities

[17] Cinergy Corp. is an unregulated subsidiary of Duke Energy Corporation.

Bay, LLC (TotalEnergies), and Cinergy Corp. (Cinergy) (together, the WEA Leaseholders) must complete various studies to develop the WEAs that will provide information on weather, wildlife, sea floor conditions, and other potential factors that may influence the sizing and locations of turbines. These studies are required through the BOEM permitting process. It will also be important to examine whether individual lease areas that neighbor each other (such as CLB East and CLB West) can be developed jointly to reduce the otherwise unused setbacks or buffer area between the lease areas. Estimated capacity is also dependent on the capacity of the individual turbines, which in turn is dependent on available technologies in production at the time that contracts are signed.

Supply chain constraints and expectations of advancement in technology can impact available capacity as well. The maximum capacity within a WEA and the energy generated are interrelated, as more turbines within the same area will increase the nameplate capacity but can reduce energy generated through the wake effect.[18] This wake effect is more pronounced for offshore wind than onshore wind due to the relatively flat water surface that does not “break” the wind.

[18] https://windpowerplus.com/the-wake-effect-in-wind-energy/.

Q. What offtake options are available for the three WEA Leaseholders?

A. The WEA Leaseholders are not restricted by whom they may contract with for the offtake of the facility output. Barring a purchase of a facility by a regulated utility, each one will conceivably operate as a merchant power producer and would contract with a party for offtake for the output of the facility. Avangrid has the clearest path to a larger pool of potential buyers because the Kitty Hawk North and Kitty Hawk South WEAs are directly offshore of the PJM RTO market via interconnection with Dominion Energy North Carolina.[19] If possible, WEA Leaseholders would likely interconnect with the utility's system with which they have contracted to sell the output of the facility, thus eliminating transmission point-to-point service charges known as "wheeling charges."

Q. Do you expect that more lease areas will become available through BOEM auctions that would be viable options for the Companies to develop?

A. Not in the immediate future. At present, there is no indication that BOEM is considering offering additional WEAs for lease off the coast

[19] Virginia Electric Power and Light Company d/b/a Dominion Energy North Carolina is a member of PJM Interconnection LLC, which operates both energy and capacity wholesale electricity markets.

of North Carolina in the immediate future.[20] DEP's service territory includes coastal areas of North Carolina and South Carolina, but DEC's does not. Therefore, any interconnection of offshore wind projects would be to DEP's system even if all or a portion of the energy were destined for DEC. While there is not a defined path for additional WEAs at this time, Duke's CPIRP modeling permitted the selection of additional tranches of offshore wind in the 2040s, representing the theoretical potential for additional WEA development. The Public Staff has also maintained this assumption in its own modeling by allowing the additional selection of up to 2.2 GW of offshore wind between 2040 and 2050. While the PS Base 2034 compliance portfolio does not select any of this additional resource, other sensitivities do select between 1.1 and 2.2 GW of additional offshore wind.

Q. What changes to the EnCompass offshore wind inputs are you supporting?

A. In Table 3 below, I present my recommended inputs for the EnCompass modeling for offshore wind. For the mutually exclusive options that are greater than 1,100 MW, I assumed that the project would come online in annual phases of 1,100 MW each.

[20] BOEM identified a potential site east of the Kitty Hawk WEAs, but it is in deep water. BOEM elected not to include this potential WEA in the proposed sale of lease areas announced on December 11, 2023.

Table 3: Recommended Offshore Wind EnCompass Inputs

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Please discuss the rationale behind these specific inputs.

A. My changes, when compared to the Companies' inputs, are all essentially a result of modifying block sizes, or the amount of MWs, that can be selected as each resource is selected.[21] Each block size is 1,100 MW, and only one of the five options can be selected prior to 2040. In the Public Staff's modeling, where the earliest possible selection date for offshore wind is 2031, the Companies' P2 Fall Supplemental planning assumptions were utilized, and only one

[21] Duke's CPIRP included three mutually exclusive offshore wind projects, consisting of 800 MW, 1,600 MW, and 2,400 MW. Each of those projects phased in at 800 MW per block. The Public Staff took the same approach, but with 1,100 MW blocks and up to five, rather than three.

block could be selected for any given year. Thus, if EnCompass selects 3,300 MW of offshore wind to meet a resource need in 2035, Option 3 in the chart above would be selected, and 1,100 MW blocks would be placed in service in three consecutive years (2033, 2034, and 2035). This modeling approach is a simplified representation to account for a possible implementation strategy. The actual deployment of offshore wind capacity will vary, given the real-world logistics that are required to complete projects of this size.

The cost figures rely on information originally provided by the Companies as the basis for my adjustments. The block size used by the Companies is 800 MW, which I changed to 1,100 MW to more closely reflect, and optimize, the sizing of the WEAs. The Companies' approach to modeling an 800-MW block is not necessarily incorrect; however, the Companies and I consider different elements in determining a reasonable project size for purposes of modeling. Also, I did not seek to model individual lease areas and have not attempted to include that level of specificity, as the highly confidential cost data collected during the offshore wind RFI is too uncertain to include in the EnCompass model at this time. I do recognize that there are risks with my approach; however, those same risks exist with any analysis at this point in time.

Based on public data, higher wind speeds occur (which results in greater energy generation potential) the further north an offshore wind resource is located off the eastern seaboard. However, based on the geographic location of the North Carolina coastal-centric WEAs, if the more northern facilities are interconnected into a central east coast area of North Carolina, a longer distance of cabling and transmission would be required, thus increasing capital costs. Accordingly, the specific inherent characteristics of each individual WEA are too speculative to attempt to replicate for modeling purposes.

Q. Please discuss how you determined the capital and transmission costs for the Public Staff's offshore wind blocks.

A. These costs are derived from the Companies' provided cost assumptions. Each of the three options are comprised of either 1,100 MW blocks or 2,200 MW blocks. Option 1 is the 1,100 MW block option, and Option 2 is the 2,200 MW block option. Each subsequent option consists of combinations of Options 1 and 2 (3,300 MW is one block of the 2,200 MW Option 2 plus one block of the 1,100 MW Option 1; 4,400 MW is two blocks of the 2,200 MW Option 2; and 5,500 MW is two blocks of the 2,200 MW Option 2 plus one block of the 1,100 MW Option 1).

The cost for the 1,100 MW block is the average cost per kW of the 800 MW and 1,600 MW block options, while the cost for the 2,200 MW block is the average cost per kW between the 1,600 MW block and the 2,400 MW block, all of which Duke used in its modeling.

In Table 4 below, I present the Companies' transmission costs alongside my recommended transmission cost estimates for EnCompass. Each upgrade number corresponds to a specific upgrade that would need to be completed to interconnect any offshore wind project. To derive these values, I reviewed the individual upgrades provided by the Companies and associated costs, and exercised judgment as to how the individual upgrades would be applied to the altered block sizes. Further, Figure 4 below shows the comparison of the total upgrade costs for each block size. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted]

[END CONFIDENTIAL]

Q. Have you provided any EnCompass modeling inputs to Public Staff witness Thomas for use in a sensitivity analysis?

A. Yes. To test the robustness of the modeling results, I provided inputs to Public Staff witness Thomas that included capping the total offshore wind capacity available for selection at 2,200 MW, and an increase in capital costs of 25%. The intent of this sensitivity was twofold: (1) to ensure that the first 2,200 MW of offshore wind capacity would still be selected, taking into consideration general inflation that has occurred since the initial modeling was completed by the Companies and to include some contingency value for potential unknown factors; and (2) to analyze the resources necessary should the Companies be able to procure only 2,200 MW of offshore wind to account for the uncertainty of multiple sea-to-land onshore areas and greenfield transmission, highlighted in more detail in Public Staff witness Metz's testimony.

Q. What are the results of that sensitivity analysis?

A. Public Staff witness Metz discusses the full results of all sensitivity analyses, but even with the 25% cost increase, 2,200 MW of offshore wind were economically selected by EnCompass and placed in service in 2033 and 2034. This, along with Duke's modeling submitted in the SPA, supports the need for offshore wind in the early to mid-2030s. However, as detailed in witness Metz's testimony, significant changes in the rate of nuclear deployment or load growth could result in a reduced need for offshore wind.

Q. What is your understanding of the Acquisition Request for Information that was proposed in the Companies' Amended Petition for Relief?

A. The Companies requested that the Commission approve an acquisition request for information (ARFI) in their SPA. The

Companies opine that the ARFI is needed to update modeling inputs and provide more surety with resource selection. My understanding of the Companies' proposed ARFI is that the underlying intent is to gain important information around the structure of the acquisition of a potential project, capital addition procurement activities, risk analysis, payment schedules, contract structures, warranty and operation information, and maintenance information, among other topics. The ARFI is intended to act as a step toward a binding solicitation process when compared to the previous request for information (RFI) that was completed by DNV. The Companies further state that the cost estimates provided through the initial RFI are now stale, and that the new ARFI would serve to update these costs.

Q. What is your opinion on the necessity of the ARFI?

A. While the Public Staff believes issuance of an ARFI is needed to provide updated cost and development information, the Companies' proposal is flawed. In the 2022 Carbon Plan proceeding, the Commission ordered the Companies[22] to evaluate the WEAs and report the findings either in or before this proceeding. While the Companies generally performed as ordered, the results of the RFI were not binding on the developers or Duke and were not directly

[22] *See* the Commission's December 30, 2022 Order Adopting Initial Carbon Plan and providing Direction for Future Planning, at 103.

incorporated into the CPIRP models.[23] The initial RFI sought much of the same information from the WEA Leaseholders that the Companies say is needed from this next ARFI.

It is not clear why, in the next CPIRP proceeding, the information gained from an ARFI conducted after the Commission's order in this proceeding would be any less stale or more binding than the results of the last RFI are in this proceeding. I am not convinced that the proposed ARFI's stated purpose can be achieved without causing more churn and resulting in a cycle of non-binding requests for information, followed by generalized incorporation into future CPIRP cycles, and dated, non-actionable cost estimates that require additional information updates. This would likely push the availability of offshore wind beyond 2035.

I acknowledge the WEA Leaseholders have previously declined to provide some of the information requested in the RFI. In my opinion, one possible reason the WEA Leaseholders have declined to provide this information is because there was limited structure in the RFI on

[23] Because of the highly sensitive and confidential nature of the data collected through the RFI, Duke did not directly input the RFI responses from the three WEAs into EnCompass and allow the model to "select" the most optimal projects. Instead, Duke synthesized and generalized the data to create representative offshore wind resources that are not directly tied or related to actual WEAs. Therefore, the data collected as a result of the RFI did not meaningfully lead to the identification of the optimal WEA for Duke ratepayers, leading to a need for the Companies' proposed ARFI. While I understand the need to keep competitive information confidential from potential market participants, I believe this limits how the results of an ARFI would or could be used for a future CPIRP.

how to provide the results and because there was no identified actionable item. Because of this, I believe WEA Leaseholders were hesitant to spend capital and resources to provide a specific level of information on a process that would not have a binding procurement. The information surrounding the asset acquisition can be difficult for the WEA Leaseholders to develop at this point in the process as the structure, and terms, are subject to negotiation. The fact that these negotiations are first-of-a-kind for a utility in this region (noting that the Coastal Virginia Offshore Wind facility is to be owned and was developed by DENC) further introduces uncertainty in the process.

Based on the Public Staff's observations, the Companies have not fully evaluated the potential of this resource, potentially to the detriment of ratepayers. While I am not advocating that the Companies pursue offshore wind at all costs or at any cost, the Companies have known for some time about the increasing load growth trends reflected in their updated load forecast and the need to identify more generation sources. Given that their own modeling analysis identifies the potential for offshore wind to help achieve least-cost carbon reduction, it is reasonable for the Companies to move forward with meaningful evaluation of offshore wind.

I recommend the Commission direct the Companies to issue an ARFI on a timeline that ensures the results will be meaningfully incorporated into the Companies' next CPIRP filing. I further recommend that the Companies promptly file the ARFI results with the Commission so that the Commission can timely determine what appropriate next steps should be undertaken by the Companies, if any, resulting from decisions made in this proceeding regarding offshore wind. Public Staff witness Metz also discusses his concerns with the Companies' ARFI proposal and identifies solutions to resolve the shortcomings of the Companies' proposal.

Q. Does the Companies' delay in issuing the ARFI, or a revised ARFI structure, impact the favorable PVRR and longer-term net zero reductions of offshore wind?

A. Yes. When one factors in the transmission infrastructure requirements and the Companies' supplemental filing, 2034 will be the earliest potential year that offshore wind will be able to come online; even then, this date is likely optimistic as multiple logistical factors would need to be considered. To account for this revised postponement, the Public Staff completed a modeling sensitivity where offshore wind was capped at 2,200 MW and was unable to be added prior to 2035. In this scenario, the full 2,200 MW was selected in 2035, adding even more certainty that offshore wind is needed for HB 951 compliance.

Witness Metz discusses offshore wind actions that are necessary for the NTAP in his testimony and identifies additional risk factors that the Commission should consider. Witness Thomas also notes how delays to the in-service date of offshore wind increase the risk that the tax credits made available through the Inflation Reduction Act will be phased out before they can be utilized for any offshore wind development.

Q. Do you have any other concerns regarding the Companies' proposed offshore wind ARFI?

A. While not quantifiable, there is a risk associated with the potential for local opposition and zoning/citing considerations for the sea-to-land landfall of the undersea cables and subsequent routing to the utility point of interconnection. Public or government opposition to the development of these WEAs could slow down or even halt the development of a project. As discussed in Public Staff witness Metz's testimony, it appears that offshore wind can be a marginally selected resource under certain conditions and sensitivities.

Should offshore wind costs materially increase, or other factors materially delay the commercial online date, other incremental generating resources could be built in place of offshore wind and obviate the need for this long-lead time asset. These risks should be considered when determining the amount of offshore wind capacity that is ultimately procured, potentially limited to no more than 2,200 MW of offshore wind at this time, unless the costs from developers participating in the ARFI are favorable. However, as noted in Public Staff witness Metz's testimony, there are limited options for bringing sea-to-land interconnections to Duke's electrical transmission system.

IV. Public Staff Recommendations

Q. Are you making any recommendations to the Commission?

A. Yes. My testimony makes the following recommendations:

1. That the Commission approve the Companies' EV load forecast included in the SPA filing as reasonable.

2. That the Commission direct the Companies to address the impact of the EPA's Vehicle Emission Standards on EV load in their next CPIRP filing.

3. That the Commission direct the Companies to continue to develop and propose tariffs designed to reduce EV load impact on coincident peak.

4. That the Companies provide an update on their onshore wind development activities in rebuttal testimony.

5. That the Companies take steps to procure onshore wind resources with appropriate joint development, ratepayer protections, and risk management, and diligently work to ensure that development of each individual site is the most prudent path forward. There is limited development potential for onshore wind energy within the Companies' service territories, and the EnCompass modeling completed by the Public Staff indicates that onshore wind energy is being selected as an economic resource across all modeled scenarios, subject to the Companies' modeling assumptions.

6. I recommend that the Commission direct the Companies to issue an ARFI on a timeline that ensures the results will be meaningfully incorporated into the Companies' next CPIRP filing. I further recommend that the Companies promptly file the ARFI results with the Commission so that the Commission can timely determine what appropriate next steps should be taken by the Companies, if any, resulting from decisions made in this proceeding regarding offshore wind.

Q. Does this conclude your testimony?

A. Yes.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

EVAN D. LAWRENCE

I graduated from East Carolina University in Greenville, North Carolina in May 2016, earning a Bachelor of Science degree in Engineering with a concentration in Electrical Engineering. I started my current position with the Public Staff in September 2016. Since that time, my duties and responsibilities have focused on reviewing renewable energy projects, rate design, and renewable energy portfolio standards (REPS) compliance. I have filed an affidavit or testimony in DENC, DEP, and DEC REPS and fuel proceedings, testimony in New River Light and Power's 2017 rate case proceeding, testimony in Western Carolina University's 2020 rate case proceeding, and testimony in multiple dockets for requests for CPCNs. Additionally, I previously served as a co-chair of the National Association of State Utility and Consumer Advocates' Distributed Energy Resources and Energy Efficiency Committee from 2019 to 2021.

CONFIDENTIAL

DOCKET NO. E-100, SUB 190

LAWRENCE EXHIBIT 1