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 joint testimony of John R. Hinton and Patrick A. Fahey of the Economic Research 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 5, 8, 11-13, 15, 22, and 24-25 of the testimony. The confidential version will be provided to those parties that have entered into a confidentiality agreement.

Sincerely,

Electronically submitted
/s/ Lucy E. Edmondson
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 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)	))))))	**JOINT TESTIMONY OF JOHN R. HINTON AND PATRICK A. FAHEY PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION**

May 28, 2024

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

A. My name is John R. Hinton. I am the Director of the Economic Research Division of the Public Staff - North Carolina Utilities Commission. My business address is 430 North Salisbury Street, Raleigh, North Carolina 27603.

Q. Briefly state your qualifications and experience.

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

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

A. My name is Patrick A. Fahey. I am a Public Utilites Regulatory Analyst with the Economic Research Division of the Public Staff - North Carolina Utilities Commission. My business address is 430 North Salisbury Street, Raleigh, North Carolina 27603.

Q. Briefly state your qualifications and experience.

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

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

A. The purpose of our testimony is to present our findings regarding the reasonableness of the peak load and energy forecasts of Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP, and collectively with DEC, Duke or the Companies), as set forth in the consolidated Carbon Plan and Integrated Resource Plan (CPIRP) filed on August 17, 2023, as well as the supporting direct testimony filed on September 1, 2023, and the Supplemental Planning Analysis (SPA) filed on January 31, 2034, as a result of significant increases in Duke's electric load forecast.

Q. Mr. Hinton, please discuss your experience with peak load and energy sales forecasts.

A. After joining the Public Staff in May of 1985, I and a fellow Public Staff economist developed forecasts for the 1986, 1989, and 1992 publications of <u>Long Range Forecasts of Peak Demand for Electricity in North Carolina,</u> which were provided to the Commission and the Governor. I filed testimony on Duke's and Progress Energy, Inc.'s peak load and energy sales forecasts in Docket Nos. E-100, Sub 50; E-100, Sub 114; and E-100, Sub 124. Since then, I have reviewed numerous peak demand and energy sales forecasts (forecasts) filed by DEC, DEP, and Dominion Energy North Carolina (DENC) in various integrated resource plan (IRP) proceedings from 1998 to the present. Mr. Fahey joined the Public Staff in January 2024, and his education in econometrics has made him integral in reviewing the Companies' forecasts.

Q. Briefly describe your review of the Companies' forecasts.

A. We have reviewed the compound annual growth rate of DEC's and DEP's forecasts of their annual peak demands and energy sales. In addition, given the large impact that weather can have on sales, and especially on peak demands, we reviewed the historical growth of weather-normalized peak demands and weather-normalized energy sales relative to prior IRPs. We also reviewed the regression equations and several of the key assumptions that underlie the forecasts, and we reviewed growth rates of forecasts for other adjoining utilities. We also reviewed Duke's SPA load forecast and the large economic development customer (mega site) load forecasts that were the impetus for Duke's supplemental filing.

Q. Do you have concerns with the Companies' forecasts of their peak demand and energy sales?

A. Yes, we have concerns with Duke's adjustments for mega sites and other large loads. Unlike the forecasts in the 2022 Carbon Plan and prior IRPs, the Companies have had a heightened level of new interest from customers planning to locate in North Carolina that are expected to have large peak demands (MW) and large annual energy sales (MWh). It is believed that many of the prospective large load customers are reacting to incentives from federal and state programs. This has prompted the Companies to make explicit adjustments outside of their traditional econometric models to account for these particular mega sites and large load customers. As has been widely reported in the media, there is a heightened level of interest from industries locating to North Carolina that is beyond previous historical levels of economic development. This growth in development is due, in part, to efforts by the Economic Development Partnership of NC and federal legislation such as the recently passed Inflation Reduction Act (IRA) and the Creating Helpful Incentives to Produce Semiconductors and Science Act (CHIPS). South Carolina is experiencing a similar development effort with approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of the prospective large load customers, by GWh of load, on the Duke system expected to develop in that service territory. Other explicit adjustments made by the Companies outside of the model in this docket were largely limited to relatively smaller levels of MWs and MWhs such as predicted changes with certain wholesale loads and new loads from electric vehicle charging.

Q. Please provide a brief discussion on the effects of an inaccurate load forecast.

A. On a high level, a significant forecast overestimation of load will generally result in excess capacity, and therefore higher ratepayer costs. The opposite, a significant underestimation of load, could result in reliability concerns on peak days, and challenges in meeting new large customer energy needs. Therefore, from a ratepayer perspective, accurate load forecasts are integral to utility resource planning.

Q. Please provide a general discussion on the forecasting methods employed by DEC and DEP.

A. DEC's and DEP's peak demand forecasts (MW) employ a monthly econometric model where they typically regress monthly peaks on three explanatory variables that account for the variation in hourly loads due to variation in warm weather, cold weather, and changes in the base level of usage. The equations typically include indicator variables for special and unique events. The independent variables account for, or attempt to explain, variation in hourly loads due to changes in weather, economics, and end-use appliances. The combination of weather data, end-use data, and economic data is an accepted practice that allows for the interactions of weather and the stock of appliances or end-uses. The estimated saturation of various end-use appliances is estimated using Statistical End-Use (SAE) data developed by Itron, Inc., that are employed in this monthly model. In addition, the SAE data include predicted end-use data over the forecast period. The Companies have employed this equation with relatively minor changes for the last ten years, which in our opinion, has generated forecasts that are reasonable for planning purposes.

The Companies' energy sales forecasts (MWh) are a product of econometric equations developed with historical monthly sales data combined with economic, demographic, and weather-related explanatory variables. The equations are derived by relating historical usage to different customer classes that allow for the quantification of energy sales to independent variables. As with forecasts of peak demand, the regression equation is combined with predictions of the independent variables to generate the forecasts. Residential sales forecasts are derived using an equation where the dependent variable is sales per customer, whereas commercial, industrial, and wholesale sector sales forecasts are based on a class level. These equations, representing organic growth, have been applied for over thirty years and are widely accepted for planning purposes. We will be referring to this base forecasting methodology as the organic forecast.

Q. Please describe the forecasts filed with the SPA as compared to recent peak demand and energy sales forecasts.

A. DEC's initially filed forecast reflected a 2024 to 2038 compound average annual growth rate (CAGR) of 1.3%, which then increased to 2.0% with the SPA. DEP's initially filed forecast reflected a CAGR of 1.1%, which then increased to 1.2% with the SPA. Previous growth rates with the 2020 and 2022 plans[1] for the winter peak and energy sales were between 0.5% and 0.8%. Following the methodology outlined in the September 1, 2023, Appendix D (Table D-11, summarizing the load impact of eight prospective large load customers), the Companies' SPA was revised to include more recent economic data and the impacts of the additional 27 prospective customers.[2] Many of the prospective customers identified in the Companies' SPA have made public announcements regarding their intent to locate within the Companies' service territories. Approximately **[BEGIN CONDFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of those prospective customers, by 2030 energy sales, have entered into agreements for future utility service, and many of those have made financial commitments. These large new customers include data centers and manufacturers, including manufacturers of electric cars. In addition, many loads from these

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[1] Dockets No. E-100, Sub 165 and 179.

[2] *See* Supplemental Testimony of Snider, Quinto, Beatty, and Passty, at 5.

customers reflect relatively high load factors with 24x7x365 operations, resulting in large energy and peak demand needs. Shown below in Figures 1-4 are graphs of the forecasts over the comparable time periods starting in 2024:

Figure 1

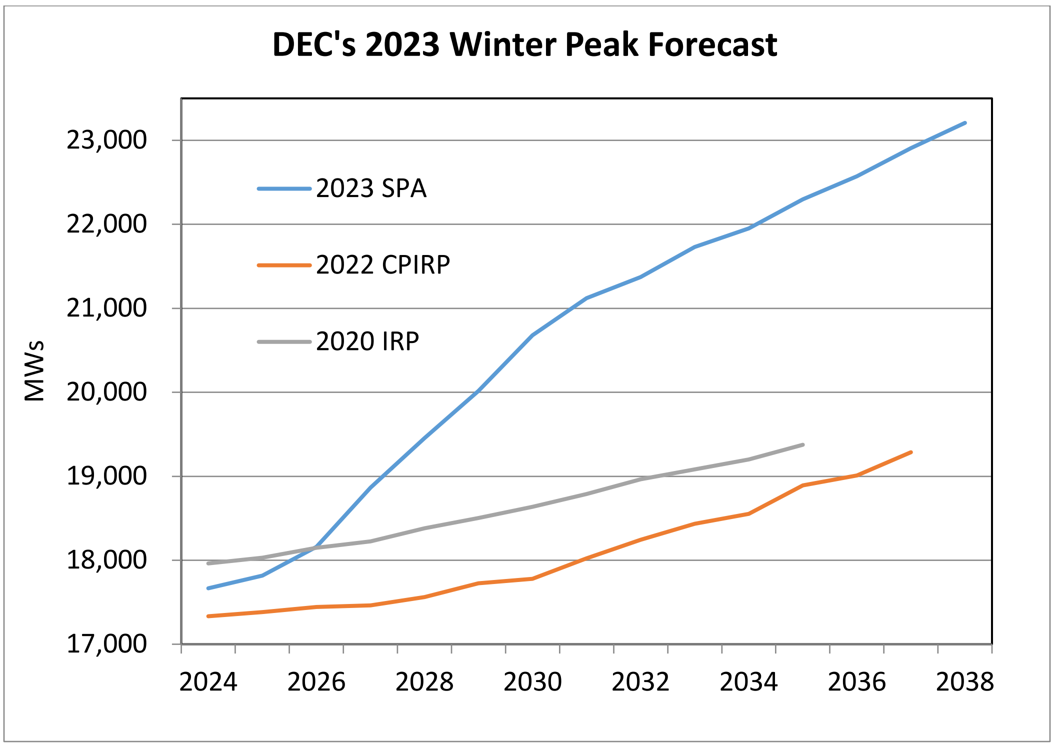


Figure 2

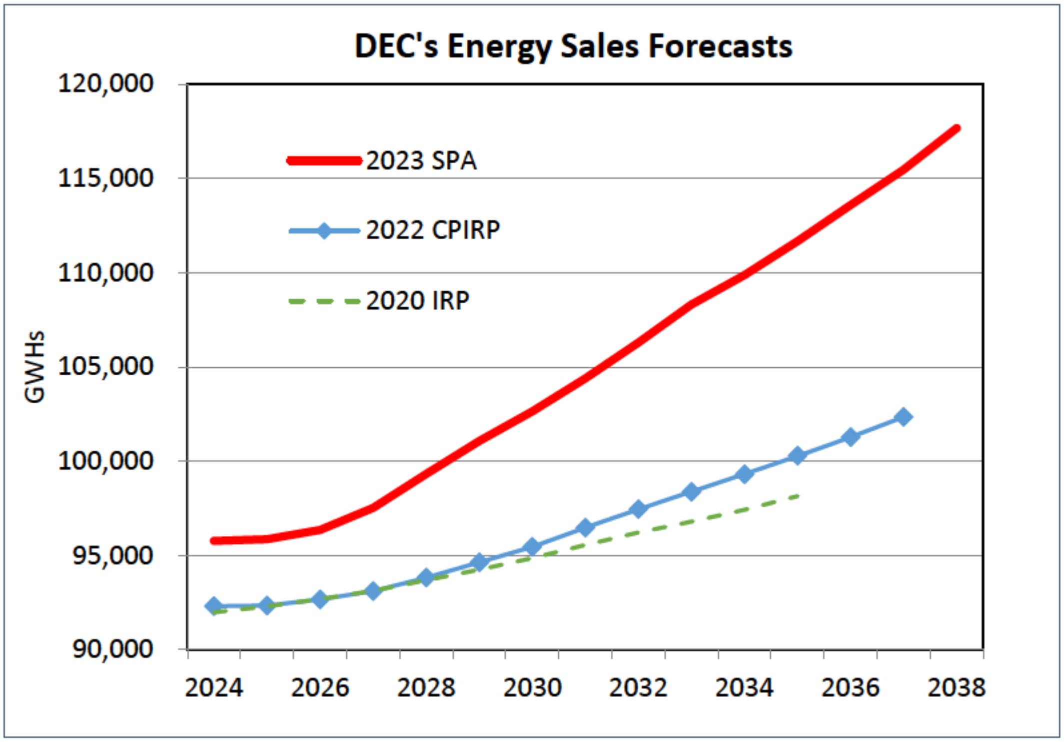


Figure 3

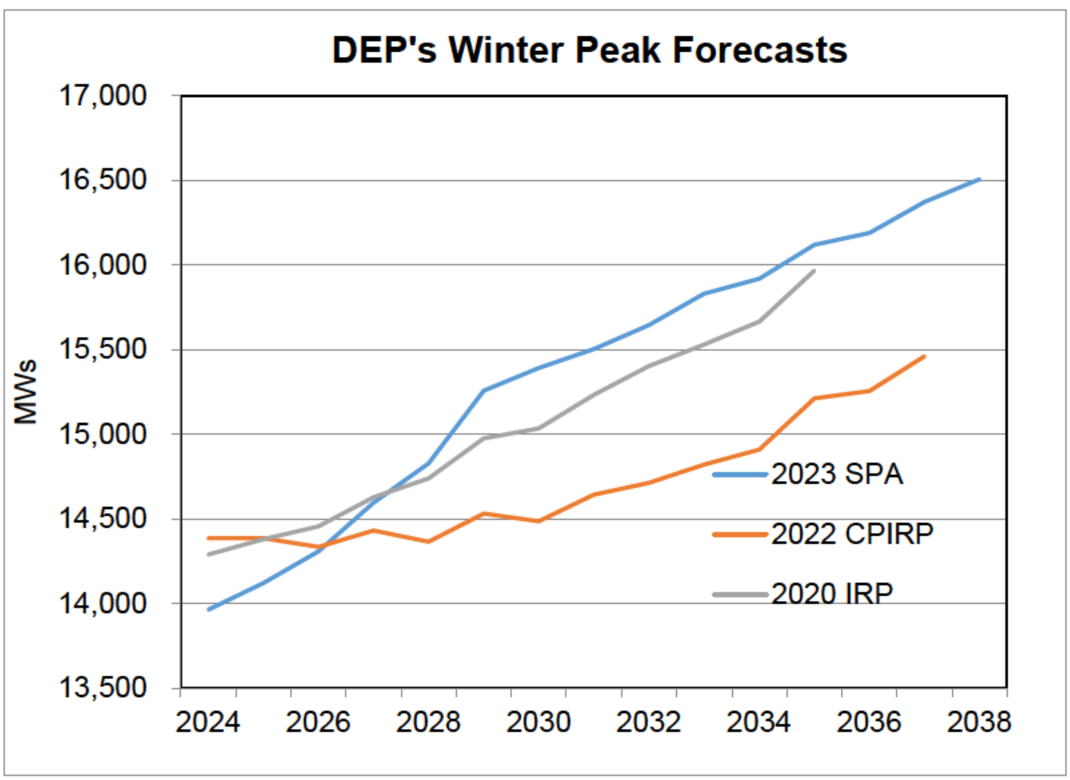
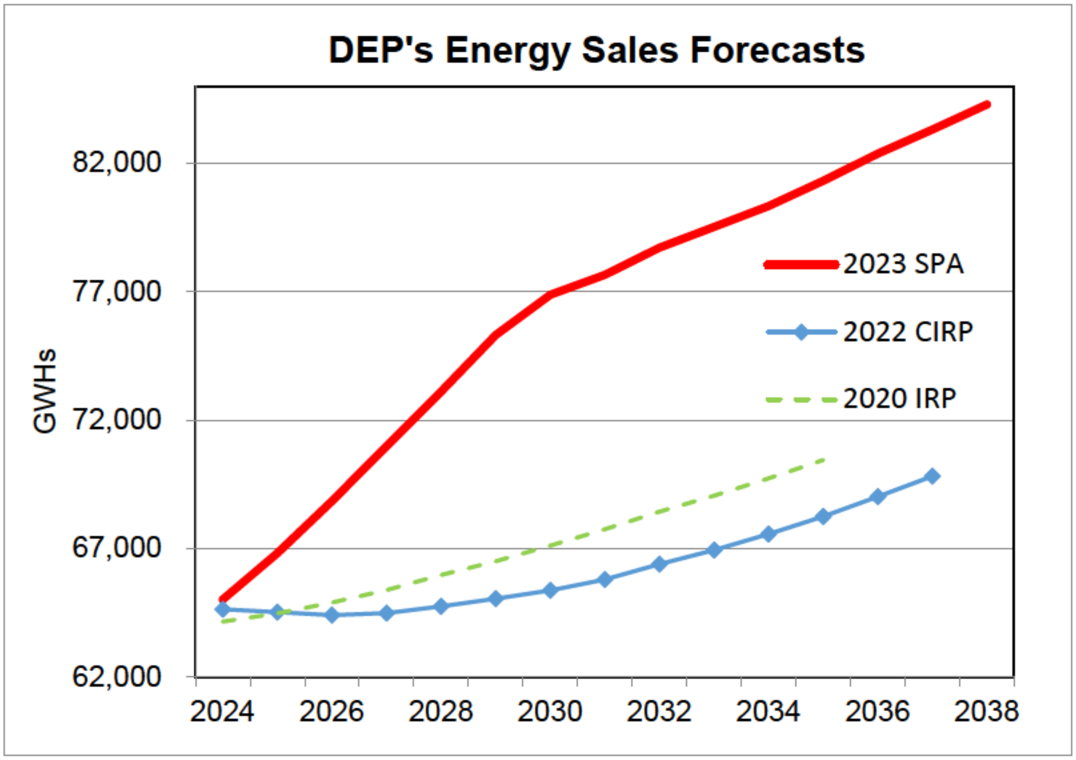


Figure 4



Q. Have you considered a high load scenario?

A. The Public Staff has not considered a load scenario higher than that provided in the Companies' SPA filing. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Our position is also supported by the potential for double counting and our concerns regarding the Companies' scaling factor methods, both of which are discussed in more detail below. If the electric load is higher than Duke forecasts in its SPA, as discussed in the testimony of Public Staff witness Jeff

Thomas, additional resources will likely be required and there may be a delay in the interim compliance date.

Q. How did the Companies identify the prospective customers with these large loads?

A. The Companies' Economic Development teams and Large Account Management teams (LAM) engage with potential projects that have shown interest in locating within their service territories. The Companies consider projects with large loads of 20 or more MWs to be mega sites. In addition, financial commitments have been made by 11 of 35 projects to take utility service.

Q. How did the Companies address the uncertainty of large load customers materializing in their SPA?

A. The Companies' LAM team has multiple levels of certainty in their planning process for the added large loads where each prospective customer is categorized**: [BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. As the model gets further into the future, the uncertainties of that load are expected to increase. An example of this uncertainty can be seen from Duke's response to a recent data request for updates on prospective large loads. For the years 2024, 2025, and 2026, the changes to Duke's forecasted load are relatively minor relative to the SPA. This indicates a relatively high degree of accuracy over the next three years. However, the changes to forecasted load were significantly larger for 2027 and beyond. The April 1, 2024 updated information on prospective customers, provided to the Public Staff through discovery, showed a decrease of approximately **[BEGIN CONDFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** from a single customer, with the overall change to Duke's SPA forecast being **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. It is worth noting that this prospective customer **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** however, it is believed that downturns in the EV market were a key decision factor. While many of these projects have current construction schedules, a significant minority do not. The significant change in forecasted large load customer energy consumption since the filing of the SPA illustrates the uncertainty of those future projects as clients update their plans based on economics and engineering changes, and due to the difficulty in correctly determining their future load accurately. The graphs in

Figures 5-6 below indicate the changes in the Companies' large load energy sales forecasts as a result of changes in expected large loads following the filing of the SPA through April 1, 2024. It should be noted that there were minimal changes in DEC as load losses were matched by new prospective customers, while in DEP there was a substantial overall decrease. In addition, in Figures 5-6 below, the Companies' scaling factor has not been applied.

Figure 5

[BEGIN CONFIDENTIAL]

[redacted]

[redacted]

[END CONFIDENTIAL]

Q. Please explain the issue of double counting of mega site loads.

A. The Companies' econometric models rely in part on macroeconomic indicators and customer trends that have historically been incorporated with their econometric forecasts. DEC's and DEP's current organic industrial energy sales forecast is largely based on the historical relationship of its total sales in relation to the industrial production index for North Carolina and the price of electricity to the average industrial customer, along with indicator variables to account for unique or special events that are unexplained by the index and prices. Previous econometric equations had similar specifications but segregated industrial sales to textile and non-textile customers or by standard industrial classification (SIC) code. DEC's and DEP's organic industrial sales forecast is based on the relationship between industrial sales, the predicted industrial production index, and predicted industrial electricity prices.

This creates a double counting concern as the predicted industrial production index variable in the econometric model likely captures some of the industrial growth, which is the large load customers, resulting in partially counting them in the model as well as explicitly adding them as an adjustment to the model.[3] Thus, some portion of these large loads is likely counted twice. The Companies maintain that the SPA load forecast with the added 35 customers is based on individual, known customers that are evaluated by the Companies' LAM team. As previously noted, the manual addition of these large loads is a relatively new forecasting method. Table 1 below shows the 2023 econometric equation that generates Duke's organic forecasts of the Companies' industrial sales:

Table 1

Billed Industrial Sales Model[1,2,4]

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
sales_b_ind.Driver	20,019.43	1116.46	17.93	0.00%	North Carolina Industrial Production Index
sales_b_ind.Price_L	-47,453.93	17509.86	-2.71	0.76%	Industrial Prices, lagged 7 months
sales_b_ind.Cool	659.47	72.00	9.16	0.00%	CDD Base 65
mBilledWeather.OCT_CDD65	-396.27	183.21	-2.16	3.23%	CDD Base 65 for October
mBilledWeather.JUL_CDD65	-273.47	93.47	-2.93	0.40%	CDD Base 65 for July
sales_b_ind.Feb	65,092.60	33840.93	1.92	5.65%	Feb Indicator
sales_b_ind.bill_flip1718	408,351.53	53618.01	7.62	0.00%	Billflip for 2017 and 2018
sales_b_ind.BC_2021	-439,863.47	76471.80	-5.75	0.00%	demand indicator for bill system changeover
sales_b_ind.late_Period	-80,549.97	36845.61	-2.19	3.05%	Demand shifter for non-summer periods Post-COVID

[3] This risk of double counting load is identified in Appendix D of the CPIRP, at 14:

> Astute readers will point out that combining such calculations with the results of an econometric model introduces a possibility of some double counting to the extent that economic forces motivate the individual site adjustments. To mitigate the impact of a possible "double count," the load forecasting team typically adjusts the load forecast by a reduced amount of the full load expectation for each project; this consideration results in a discount of 30%–60%, depending on the extent to which informal statistical calculation suggests that aggregate sales are explained by the relevant economic indicator for that customer class.

Q. Please discuss the impacts of these large loads on the overall peak and energy forecasts.

A. In order to investigate the 2023 forecast, the Public Staff used Duke's organic load forecasts, which are without any of the large loads, so as to make the forecasts reasonably comparable to the 2022 Carbon Plan forecasts filed in Docket No. E-100, Sub 179. The 2022 forecast CAGRs for DEC's winter peaks and annual energy sales was 0.8% over the period of 2023-2037. For that same period, the 2022 forecast CAGRs for DEP's winter peaks and annual energy sales was 0.6%. The predicted growth in peak demands equated to an average annual growth of 147 MW for DEC and 113 MW for DEP; furthermore, the CAGRs in the 2022 Carbon Plan were very comparable to filed IRPs since 2000.

For the CPIRP SPA organic load forecasts, DEC's 2024-2038 CAGRs with its peak forecast had increased to 1.3% for winter peak and 1.6% with its energy sales. Meanwhile DEP's winter peak CAGR increased to 0.8% and 1.2% with its energy sales. The predicted average annual growth in peak demand is 343 MW for DEC and 182 MW for DEP. What is worth noting is that the organic forecasts contained significant increases in the Companies' CAGRs for the winter peaks and the annual energy sales relative to the 2022 forecasts. Naturally, the 2023 forecast will have a higher starting point due to one year of added growth; however, it's another question as to why these long-term organic growth rates, excluding the large loads, are significantly higher after years of lower growth. A likely explanation is that the Companies' econometric model already includes some of the growth associated with the expected large loads, which supports concerns with double counting. The graphs in Figures 7-8 below demonstrate the forecast growth with the large load customer energy removed, and the higher growth rate in 2026 to 2030 in DEC demonstrating the Public Staff's concern regarding the double counting of load.

Figure 7

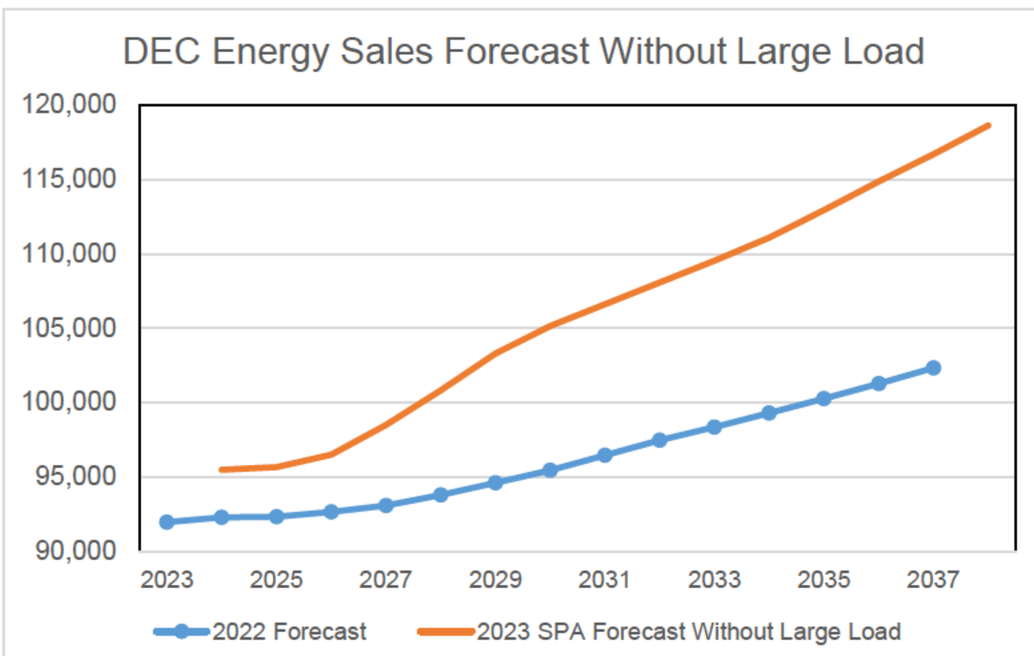
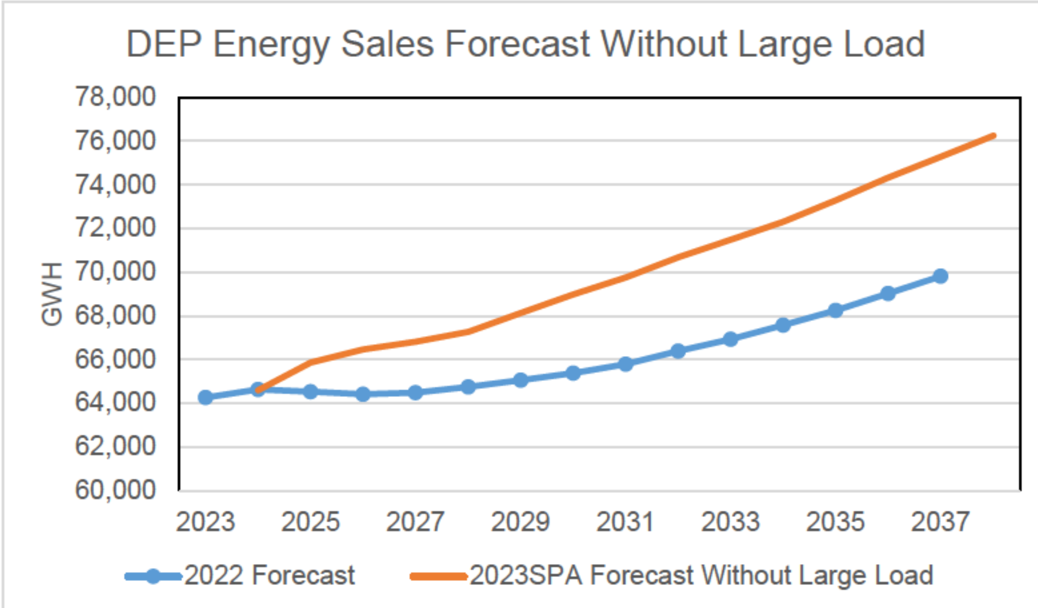


Figure 8



The years of greatest growth are when most of the mega sites begin operation, with the CAGRs including large load from 2025-2030 being 3.02% for the winter peak and 3.96% for energy sales in DEC; and 1.74% for the winter peak and 2.85% for energy sales in DEP. This change is quite significant given the two previously filed load forecasts in 2022 and 2020 that reflected predicted forecast CAGRs between 0.6% and 0.8% and CAGRs for energy sales between 0.5% and 0.8%. The significant load growth during this period is a substantial contributing factor in the "critical period" between 2027 and 2033, described in witness Thomas' testimony. Below is Table 2, which shows DEC's and DEP's SPA forecasts with the annual growth in MWs. Table 2 reveals the incremental growth in the peaks and the higher growths in DEC relative to DEP.

Table 2

	DEC			DEP		
Year	SPA Winter Peaks	Annual Load Growth	CAGR from 2024	SPA Winter Peaks	Annual Load Growth	CAGR from 2024
2024	17,666	NA		13,964	NA	
2025	17,817	81	0.9%	14,122	158	1.1%
2026	18,158	316	1.4%	14,309	187	1.2%
2027	18,864	635	2.2%	14,597	288	1.5%
2028	19,454	429	2.4%	14,829	232	1.5%
2029	20,017	427	2.5%	15,257	428	1.8%
2030	20,679	553	2.7%	15,392	135	1.6%
2031	21,119	423	2.6%	15,504	112	1.5%
2032	21,374	232	2.4%	15,645	141	1.4%
2033	21,732	334	2.3%	15,831	186	1.4%
2034	21,950	253	2.2%	15,919	88	1.3%
2035	22,297	271	2.1%	16,120	201	1.3%
2036	22,573	265	2.1%	16,189	69	1.2%
2037	22,907	311	2.0%	16,374	185	1.2%
2038	23,208	268	2.0%	16,507	133	1.2%
2024-38 Growth Rate	2.0%	343		1.2%	182	

Q. How did the Companies adjust for double counting?

A. Duke applied scaling factors to each of the 35 prospective large loads, which reduced the load used in the CPIRP relative to the actual load requested from the LAM by the customers. This was partially done with regression analysis where historical industrial sales were regressed against an industrial production index and autoregressive terms. Similarly, for large commercial customers, they regressed weather normalized sales with real household median income for DEC and commercial employment index for DEP.

From the regression analysis, the Companies' scaling factors were developed using the unexplained variation from the regression known as fraction of variance unexplained (FVU). The explained variation is commonly referred as the R-square statistic.

This analysis was then used as a benchmark for informed discussion between the LAM and Economic Development teams who then used their informed judgement to set discount factors and the timing of new loads. While the Companies' originally filed Appendix D noted that the scaling factors were between 30% and 60%, the average energy scaling factor[4] across all classes and years is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** with greater discounts **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in early years of projects, and lower discounts **[BEGIN CONFIDENTIAL]** [redacted] [redacted] [redacted] [redacted] **[END CONFIDENTIAL]** in later years.

Q. Do you have concerns with the estimated scaling factors?

A. Yes. Any attempt to translate proposed customer demand for individual large customers, also referred to as clients, many years into the future is a great challenge when one considers the uncertainties regarding economic conditions, construction delays,

[4] The commercial scaling factors were grouped by data centers and non-data center load.

and technological changes. Furthermore, this forecasting method reflects a methodological change in the Companies' forecasting of its industrial load from prior IRP dockets. The Companies' use of scaling factors is discussed by the Companies, who stated that they "applied a downward adjustment to reflect both uncertainty and future oriented nature of economic development plans and the risk of double counting."[5] It should be noted that their scaling factors do not appear to directly account for project delays, reduced operations, or cancelations; rather, these factors are relegated as "uncertainty." However, the regression equation underlying the scaling factors does not appear to directly account for these scenarios. Duke's responses to Public Staff data requests indicate that the scaling factor analysis was used as a benchmark with customer interactions, along with the Companies' informed judgment, to develop the scaling factors.

The Public Staff has reservations about whether the purported scaling factors are reasonably accurate given the lack of historical data on data centers and the rush of interest from industrial customers with large loads. This load may never materialize in the Companies' service territories. As such, we sense a higher level of forecast uncertainty as compared to the prior industrial forecasting

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[5] *See* Appendix D, at 14.

method that relied on established methods. The regression equations that underly the scaling factors for DEC incorporated household median income as an independent variable; however, for DEP, the Company incorporated the commercial employment index as an independent variable. Shown below are graphs in Figures 9-10, of the Companies' scaled large loads relative to their clients' expected energy sales.

Figure 9

[BEGIN CONFIDENTIAL]

[redacted]

[redacted]

[END CONFIDENTIAL]

As the rapid growth and large load challenges approach, the Public Staff believes that a more robust model is needed either using the limited available data of existing data centers and industrial load in North Carolina or other predictive methods.

Q. Do you have an alternate approach?

A. Yes. For this proceeding, we propose that an alternative forecast that removes virtually all double counting can be generated with the use of the load forecasts from the 2022 Carbon Plan as a base load scenario, and adding the 35 prospective large loads. Given the relatively stable organic load forecasts of the last couple of years, it is not unreasonable to assume that the 2022 load forecast is a reasonable organic forecast where the noted large loads can be added. This alternative forecast would provide a lower end of the range of potential future load and be instructive as the parties and the Commission consider the CPIRP. The Public Staff has developed this alternative forecast and presents it below.

Q. How did you apply the 2022 load forecasts?

A. We grossed up the hourly load shapes to mimic the load shapes embedded in the SPA in the 2022 forecast and then effectively added the prospective large loads in order to yield a lower load forecast to remove the possibility of double counting. The adjustment made to the 2022 energy forecast to mimic the 2023 forecast was done in several steps. First the Energy Efficiency (EE) programs from the CPIRP were applied to the 2022 forecast, replacing the 2022 EE. Next, the scaled large loads from the SPA were applied, and the forecast was offset to align with the most recent actual data from the 2023 SPA forecast beginning year. Lastly, in order to keep the hourly data consistent with the 2023 SPA forecast, the percentage difference on an annual basis between the adjusted 2022 forecast and the 2023 SPA forecast was applied to scale down the 2023 SPA hourly data from 2024 to 2037.

Due to more limited data after 2037, the difference in CAGRs was used from 2037-2050. The difference resulted in an average annual total load decrease of 8.3% for DEC and 6.1% for DEP. These data and the alternate load forecast were then modeled in EnCompass by witness Thomas, with the sensitivity results discussed in witness Thomas' testimony. While this model includes the individual large load projects from the SPA, it does not include the April 1, 2024 updated load changes or additional economic activities associated with those projects, known as spillover effects, that are mixed in and statistically indistinguishable from the double counting issue. Therefore, the 2022 forecast, when adjusted as above, provides a minimum scenario with no double counting. The Public Staff's alternative forecast for DEC's and DEP's energy sales are shown below in the graphs in Figures 11-12.

Figure 11

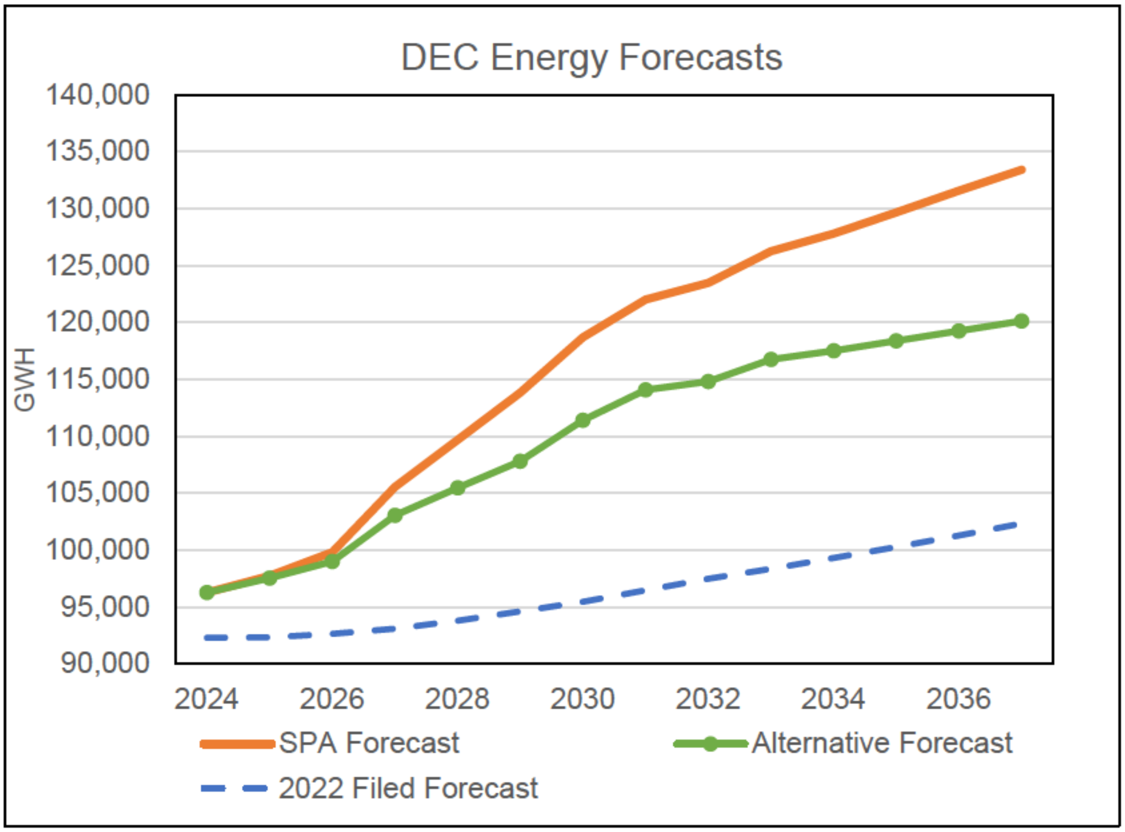
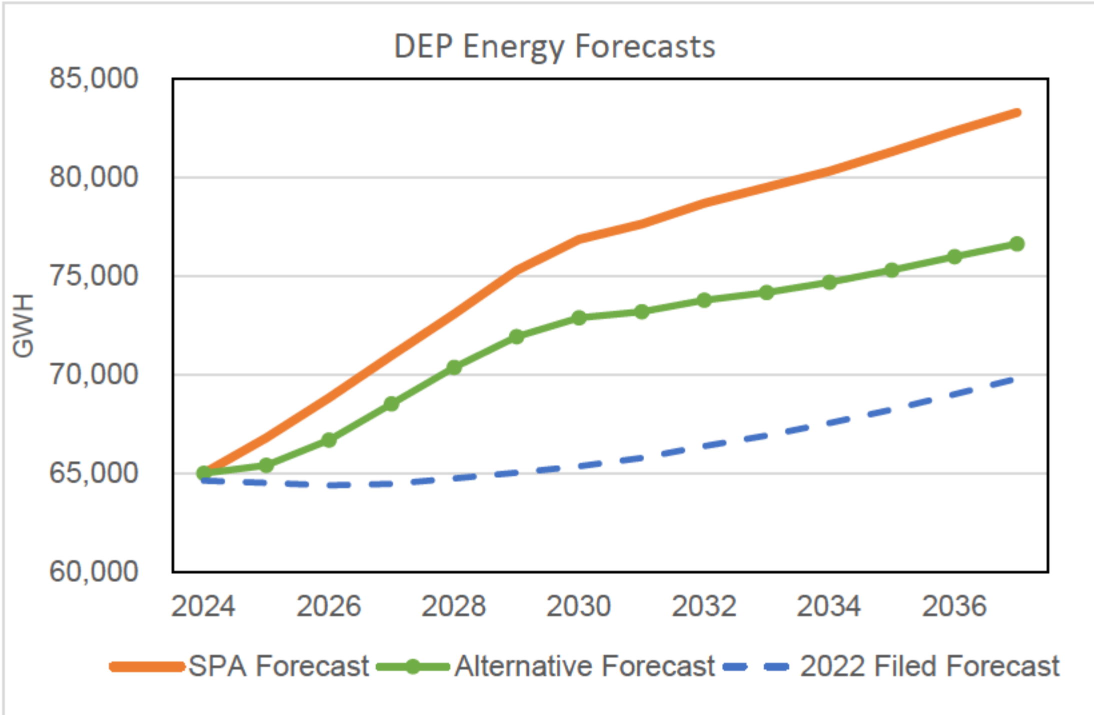

DEC Energy Forecasts
GWH
140,000
135,000
130,000
125,000
120,000
115,000
110,000
105,000
100,000
95,000
90,000
2024
2026
2028
2030
2032
2034
2036
SPA Forecast
Alternative Forecast
2022 Filed Forecast

Figure 12



Q. Are there other ways that the Companies could have accounted for the uncertainties associated with these prospective large loads?

A. Yes. Georgia Power Company is also experiencing a similar trend of substantial interest from data centers and other mega sites with large loads. In response to this heightened interest, Georgia Power Company developed a Load Realization Model (LRM).[6] Its model contains a set of probabilities assigned to the customer types and a

[6] GA. Public Service Commission, Public Interest Advocacy Staff, Direct Testimony of Robert Trokey, Kathleen Kelly, and Karan Pol, Amended 2023 Integrated Resource Plan Update, Docket No. 55378.

set of assumptions to the extent that the project might be delayed from the intended in-service dates or operate at a lower load. These possible scenarios are statistically modeled in Monte Carlo simulations where Georgia Power Company decided to use a P95 forecast level, meaning that of the 100,000 iterations that make up the Monte Carlo simulation, 95,000 of them produced a load forecast at or below the final forecast originally selected.

As with all simulations, the assigned probabilities are crucial to the outcomes. The advantage of this approach, however, is that there is an explicit recognition of project delays and cancelations in the model inputs, as well as the use of uncertainty in the Monte Carlo model structure. DEC's and DEP's scaling factor, on the other hand, assumes that all of the prospective projects will ultimately take service, but at scaled down levels.

Q. Do you have any recommendations to account for the uncertainty associated with the large load mega sites?

A. Yes. The Public Staff makes the following recommendations:

1. That in future CPIRPs, the Companies consider using advanced predictive methods for large load customers that are forward-looking and use probabilities that explicitly account for possible project cancelations, delays, and other forms of future uncertainty, such as

a Monte Carlo simulation similar to the one employed by Georgia Power.

2. That the Companies continue to monitor data center load in their service areas and update the Public Staff on a quarterly basis of changes in large load customers' energy and peak loads and service agreement status, in addition to information on new prospective large load customers, including their respective industries.

3. That the Companies monitor growth in Virginia, Georgia, and other pockets of development to better understand data center and large load customer behaviors and loads.

Q. Does this conclude your testimony?

A. Yes.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

JOHN ROBERT HINTON

I received a Bachelor of Science degree in Economics from the University of North Carolina at Wilmington in 1980 and a Master of Economics degree from North Carolina State University in 1983. I joined the Public Staff in May of 1985. I filed testimony on the long-range electrical forecast in Docket No. E-100, Sub 50. In 1986, 1989, and 1992, I developed the long-range forecasts of peak demand for electricity in North Carolina. I filed testimony on electricity weather normalization in Docket Nos. E-7, Sub 620, E-2, Sub 833, and E-7, Sub 989. I filed testimony on customer growth and the funding for nuclear decommissioning costs in Docket No. E-2, Sub 1023. I filed testimony on funding for nuclear decommissioning costs in Docket Nos. E-7, Sub 1026 and E-7, Sub 1146. I have filed testimony on the Integrated Resource Plans (IRPs) filed in Docket No. E-100, Subs 114 and 125, and I have reviewed numerous peak demand and energy sales forecasts and the resource expansion plans filed in electric utilities' annual IRPs and IRP updates.

I have been the lead analyst for the Public Staff in numerous avoided cost proceedings, filing testimony in Docket No. E-100, Subs 106, 136, 140, 148, and Sub 158. I have filed a Statement of Position in the arbitration case involving EPCOR and Progress Energy Carolinas in Docket No. E-2, Sub 966. I have filed testimony in avoided cost related to the cost recovery of energy efficiency programs and demand side management programs in Dockets Nos. E-7, Sub 1032, E-7, Sub 1130, E-2, Sub 1145, and E-2, Sub 1174.

I have filed testimony on the issuance of certificates of public convenience and necessity (CPCN) in Docket Nos. E-2, Sub 669, SP-132, Sub 0, E-7, Sub 790, E-7, Sub 791, and E-7, Sub 1134.

I filed testimony on the merger of Dominion Energy, Inc. and SCANA Corp. in Docket Nos. E-22, Sub 551, and G-5, Sub 585, the merger of Ullico and Frontier Natural Gas in Docket No. G-40, Sub 160.

I have filed testimony on the issue of fair rate of return in Docket Nos. E-22, Subs 333, 412, and 532; E-34, Subs 46 and 54, P-26, Sub 93; P-12, Sub 89; P-31, Sub 125; G-21, Sub 293; P-31, Sub 125; P-100, Sub 133b; P-100, Sub 133d (1997 and 2002); G-21, Sub 442; G-5, Subs 327, 386; and 632; G-9, Subs 351, 382, 722 and 781, W-778, Sub 31; W-218, Subs 319, 497, 526, and 573; W-354, Sub 360, 364, 384, and 400 and in several smaller water utility rate cases. I have filed testimony on financial metrics and the risk of a credit rating downgrade in Docket No. E-7, Sub 1146.

I have filed testimony on the hedging of natural gas prices in Docket No. E-2, Subs 1001, 1018, 1031, and 1292. I have filed testimony on the expansion of natural gas in Docket No. G-5, Subs 337 and 372. I performed the financial analysis in the two audit reports on Mid-South Water Systems, Inc., Docket No. W-100, Sub 21. I testified in the application to transfer of the CPCN from North Topsail Water and Sewer, Inc. to Utilities, Inc., in Docket No. W-1000, Sub 5. I have filed testimony on rainfall normalization with respect of water sales in Docket No. W-274, Sub 160. I have filed testimony on the transfer of Bald Head Island Transportation and Bald Head Limited, Inc. in Docket A-21 Sub 22.

With regard to the 1996 Safe Drinking Water Act, I was a member of the Small Systems Working Group that reported to the National Drinking Water Advisory Council of the U.S. Environmental Protection Agency. I have published an article in the National Regulatory Research Institute's Quarterly Bulletin entitled Evaluating Water Utility Financial Capacity.

I have filed testimony on the expansion of natural gas in Docket No. G-5, Sub 337 and Docket No. G-5, Sub 372. I performed the financial analysis in the two audit reports on Mid South Water Systems, Inc., which were filed in Docket No. W-100, Sub 21. I have filed testimony on weather normalization of water sales in Docket No. W-274, Sub 160.

With regard to the 1996 Safe Drinking Water Act, I was a member of the Small Systems Working Group that reported to the National Drinking Water Advisory Council of the U.S. Environmental Protection Agency (EPA). Since my involvement with the EPA, I have published an article in the National Regulatory Research Institute's (NRRI's) Quarterly Bulletin entitled Evaluating Water Utility Financial Capacity.

APPENDIX B

QUALIFICATIONS AND EXPERIENCE

PATRICK ALEXANDER FAHEY

I received a Bachelor of Science degree in Economics from the University of North Carolina at Charlotte in 2018 and a Master of Economics degree from North Carolina State University in 2023. Since joining the Public Staff in January of 2024, I have testified on the cost of capital for small water and wastewater utilities and I have been involved in the Public Staff's investigation of Docket No. E-7, Sub 1304 and the 2023 Biennial Avoided Costs in Docket No. E-100, Sub 194.