DIRECT TESTIMONY
OF
EDWARD H. BAINE
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 694

Q. Please state your name, position of employment, and business address.

A. My name is Edward H. Baine, and I am President of Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company"). My business address is 600 East Canal Street, Richmond, Virginia 23219.

Q. Please describe your area of responsibility within the Company.

A. I lead the Company's regulated electric utility business in its North Carolina and Virginia service areas and I am responsible for the operational and financial performance of the Company. A statement of my background and qualifications is attached as Appendix A.

Q. Have you previously testified before this Commission?

A. No. I have provided testimony to the State Corporation Commission of Virginia in a number of proceedings, most recently in the Company's Virginia Biennial Rate Review in Case No. PUR-2023-00101.

Q. Please summarize your testimony in this proceeding.

A. My testimony introduces DENC's request for an increase in its base rates and charges as presented in the application ("Application") and explains the

Company's need to obtain the rate relief and the authorized return requested in the Application. I present an overview of the Company's recent capital investments for the benefit of our customers and describe the Company's outstanding operational performance delivering reliable, cost-effective, and environmentally responsible electric service to its North Carolina customers. I discuss the drivers of the Company's request and explain how the adequate return on equity ("ROE") of 10.60% the Company is requesting will allow the Company to attract capital on reasonable terms and thus minimize the cost of capital for customers and ensure our ability to continue to improve our systems for our customers' benefit.

I also discuss the ways in which the Company continues to improve the electric service and customer service provided to our North Carolina customers. It is important to DENC to participate in and contribute to our local communities, and my testimony describes the ways in which we have and continue to support and engage with our North Carolina service area customers and community partners. As always, the Company maintains its focus on delivering reliable electric power to customers at competitive cost; my testimony also summarizes the overall rate impact of our proposals, under which our customers' average rates will remain competitive with average rates for similar utilities in this region. The Company remains focused on outstanding operational performance and innovation to provide an exceptional customer experience, and to contributing in many ways to the well-being of the people, businesses, and other institutions in our service territory.

Finally, I introduce the deferral and service terms requests the Company is making with the Application and briefly introduce the other Company witnesses who sponsor testimony supporting the Company's Application.

Q. How is your testimony organized?

A. My testimony is organized as follows:

I. Overview

II. Major Case Drivers

III. Service to Customers

IV. Proposed Accounting and Tariff Changes

V. Proposed Rate Adjustments

VI. Conclusion

I. OVERVIEW

Q. Please describe the Company's North Carolina operations.

A. The Company is a wholly-owned subsidiary of Dominion Energy, Inc. that generates and distributes electricity for sale in North Carolina and Virginia. In Virginia, the Company conducts business under the name Dominion Energy Virginia and in North Carolina it conducts business under the name Dominion Energy North Carolina. The Company plans and operates its North Carolina and Virginia service areas as a combined system.

DENC provides electric service to over 127,000 customers in northeastern North Carolina, with a service territory of about 2,600 square miles, including Roanoke Rapids, Ahoskie, Williamston, Elizabeth City, and the Outer Banks.

DENC serves multiple large industrial facilities as well as federal, state, commercial, and residential customers. During the 2023 test year, the Company's North Carolina jurisdictional sales totaled 3.9 million megawatt-hours ("MWh"). Additionally, the Company provides power and/or transmission services to the North Carolina Electric Membership Corporation, the North Carolina Eastern Municipal Power Agency, and the Town of Windsor, which in turn provide service to approximately 100,000 customers. The Company is a member of the PJM Interconnection, L.L.C. ("PJM") regional transmission organization, which coordinates the wholesale electric grid in the Mid-Atlantic region of the United States.

Q. Why does the Company need to increase its base rates at this time?

A. This is the first North Carolina rate case the Company has filed in five years, since the last case was filed in Docket No. E-22, Sub 562 (the "2019 Rate Case"). The Company's Application is necessitated by its recent, and continuing, significant investments in generation, transmission, and distribution for the benefit of DENC's customers, as well as in response to increases in environmental compliance costs and other operating expenses that have occurred since the North Carolina Utilities Commission ("Commission") last approved base rates for the Company in the 2019 Rate Case. The Company is also experiencing significant cost pressures from a combination of persistent inflation, high interest rates, and higher costs for contract labor, material, pension and other employee benefits, among other factors. The Company is requesting to increase base rates at this time because its current rates are no longer "just and reasonable," as they are increasingly insufficient to recover the Company's costs to serve customers and to provide the return required by the investors who fund the Company's capital requirements. Specifically, while the Commission approved a 9.75% ROE in the 2019 Rate Case, as of December 31, 2023, the Company is earning 5.01% ROE.

The Company is committed to providing reliable and cost-effective electric service 24 hours a day, 365 days of the year. This means ensuring that the residents, businesses, industries, churches, schools, hospitals, local governments, and other customers across DENC's service area receive highly reliable electric service at reasonable rates. Affordable, cost-effective rates are key to our customers' well-being and satisfaction, as well as to economic development and vitality across our North Carolina service area. This commitment requires DENC's constant attention to efficient operations, customer service, and updating and maintaining our infrastructure.

In addition, the Company has continued to experience new load growth driven largely by data center expansion, economic growth, and electrification. Company Witnesses Kevin L. Fields, Robert E. Miller, and Paul M. McLeod/Christopher J. Lee address the impacts of this continuing growth on our system.

To meet these challenges, DENC has continued to invest in key infrastructure for the benefit of its North Carolina customers. These infrastructure investments include: utility-scale solar generation facilities; battery storage facilities; the Coastal Virginia Offshore Wind ("CVOW") pilot project; electric delivery system projects; and investments in our fossil and nuclear fleets, including in projects related to subsequent license renewal ("SLR") to maintain continued safe, reliable, and efficient electric generation for the benefit of our customers.

Collectively, these investments expand the Company's renewable generation portfolio and further reduce its carbon footprint, continue the Company's efforts to enhance system reliability, and emphasize the Company's commitment to environmental compliance. In summary, our focus on these areas will allow the Company to provide reliable and cost-effective electric service to North Carolina customers over the long term.

Q. Why is the Company requesting a 10.60% ROE in this case?

A. For many of the same reasons that the Company has made significant investments in its generation, transmission, and distribution systems since the 2019 Rate Case, we will need to continue to make further investments over the next several years. To attract the capital needed to meet these substantial future capital needs, the Company must achieve an adequate authorized ROE in this proceeding. The 10.60% ROE the Company is requesting through expert-supported evidence in this case will allow DENC to attract capital on reasonable terms in the still-volatile and highly competitive capital markets. This ability to attract capital on reasonable terms is important to DENC's ability to maintain its current credit ratings, and ultimately, minimize the cost of capital for its customers. An adequate return that enables the Company by sound management to produce a fair return for its shareholders, considering changing economic conditions and other factors as required by North Carolina law, also helps ensure the Company's ability to commit capital to future construction projects in order to provide electric service to its North Carolina customers in a safe, reliable, and cost-effective manner. Company Witness Jennifer E. Nelson discusses the Company's capital needs in detail in her testimony, while Company Witness Richard M. Davis, Jr. analyzes the Company's cost of equity capital, and then explains and justifies the ROE for which the Company is seeking approval in this proceeding.

II. MAJOR CASE DRIVERS

Q. What major changes in capacity have occurred within the fleet since the 2019 Rate Case?

A. Since the 2019 Rate Case, the Company has brought online 10 solar generation facilities capable of generating approximately 540 MWac of utility scale solar totaling nearly $1 billion, as well as 36 MW of storage capacity costing approximately $73 million. These capacity additions are an important part of the Company's portfolio for achieving net zero carbon emissions. Additionally, the Company's CVOW pilot project, which consists of two 6 MW (nominal) wind turbine generators ("WTGs"), achieved commercial operations in January 2021. Company Witness Jeffrey G. Miscikowski provides further details on these projects. Finally, the Company retired Chesterfield Power Station units 5 and 6 and Yorktown Power Station unit 3 in 2023, which represented a total 1804 MW of coal- and oil-fired generation capacity, and retired Possum Point unit 5, with 770 MW of oil-fired capacity, in 2020. Company Witness Jeffrey D. Matzen provides additional details on these retirements.

Q. Please provide an overview of the other capital investments in generation that the Company has made since the 2019 Rate Case.

A. As discussed further by Company Witness Miscikowski, the Company has invested over $480 million in its nuclear fleet since 2019 through 2023, in addition to investments in SLR projects of approximately $985 million. The Company's nuclear units are a vital and significant baseload source of zero-carbon generation. Extending the operating life of this fleet by another 20 years through SLR will allow DENC to continue provide clean and affordable electricity well into the future.

Witness Miscikowski also discusses the Company's investments in its natural gas and coal fleets. These investments include maintenance capital projects with the combined cycle and combustion turbine fleet and investments to the Mount Storm Power Station to comply with federal environmental requirements.

Q. Please explain how the Company has invested in other areas of its system in North Carolina since 2019.

A. As discussed by Company Witness Kevin L. Fields, since 2019, DENC has continued to expand and strengthen its transmission and distribution infrastructure in northeastern North Carolina, and throughout its system, as part of its mission to ensure reliability, operational excellence, and efficient service for customers.

Specifically, from 2019 through 2023, the Company spent approximately $316 million on transmission improvements in North Carolina, which included rebuilding and refurbishing approximately 57 miles of existing 230 kV lines and 65 miles of existing 115 kV lines.

Likewise, as Witness Fields explains, the Company maintains a strong focus on maintaining and improving its distribution system in North Carolina and has invested approximately $47 million in this system since the 2019 Rate Case to support load growth and improve reliability. This work included the construction of a new distribution substation, new circuits, and extensive improvements to existing substations and transformers at a number of sites, along with extensive line work to rebuild aged infrastructure.

Q. Are there other significant costs the Company incurs to meet customer demand and load growth?

A. Yes. As noted by Company Witness McLeod, purchased power expenses (both capacity and energy) have increased significantly since the 2019 Rate Case. The amount reflected for ratemaking in this case is approximately $10 million greater than the amount approved in the 2019 Rate Case.

Q. Please discuss the environmental compliance investments the Company has made since the 2019 Rate Case.

A. The Company has made significant investments since the 2019 Rate Case to comply with federal and state compliance requirements, including approximately $620 million related to the management and disposal of coal combustion residuals ("CCR" or "coal ash") at certain of the Company's coal-fired power plants. Witness Miscikowski provides detailed information supporting costs incurred in connection with CCR remediation projects as required by federal and state law.

Q. What are the Company's plans for future capital investments?

A. For the period 2025 to 2029, the Company is planning overall capital investments of approximately $35.5 billion, of which significant amounts are projected to be made for electric transmission and distribution infrastructure; solar and offshore wind generation, as well as battery storage; its nuclear operations and subsequent license renewal; and other maintenance, environmental, and generation capital. As I note above, the Company is seeking an adequate authorized ROE in this proceeding to attract the capital needed to meet these substantial future capital needs.

III. SERVICE TO CUSTOMERS

Q. In your opinion, and based upon your experience, has the Company made reasonable and prudent investments in its generation fleet to ensure adequate and reliable electric service to DENC's customers in North Carolina?

A. Yes. In my opinion, these investments have been prudently incurred and were necessary to ensure adequate and reliable electric service to DENC's retail customers in North Carolina.

Q. In your view, is the Company furnishing adequate, efficient, and reasonable service to its North Carolina customers?

A. Absolutely. North Carolina's Public Utilities Act requires that the state's utilities provide "adequate, efficient and reasonable service." In my view, the Company has consistently met this standard over the past few years by providing outstanding operational performance for its customers. This included when the Company's investments in our grid infrastructure and diverse generation fleet were critically tested in December 2022, during Winter Storm Elliott over the Christmas holiday, and our system performed reliably for our customers. And we continue to demonstrate outstanding performance metrics in fair weather times as well.

In the area of generation performance, the Company's fleet has consistently delivered exceptional value for its customers since 2019. One critical benchmark of generation performance is the Equivalent Forced Outage Rate on demand ("EFORd"). For the years 2019-2022, which represent the most current data available, the Company's EFORd results have compared notably superior to its peers, with fleet performance levels significantly better than PJM region's average as noted in the following table:

EFORd	2019	2020	2021	2022
Dominion	2.99	5.73	6.8	5.34
PJM	5.5	6.2	7.0	7.6

The Company's nuclear fleet has also maintained its record of industry leading performance over the past few years. The most recently published

NERC Generating Unit Statistical Brochure indicates an industry average capacity factor of 92.87% for comparable units for the five-year period of 2018 through 2022; the Company's nuclear fleet operated at a 92.9% capacity factor during that time period. The Company's nuclear units at North Anna and Surry had a capacity factor of 94.69% for 2023.

Finally, the Company has invested strategically to expand and strengthen its transmission and distribution infrastructure in northeastern North Carolina, and throughout its system, as part of DENC's core mission to ensure reliability, operational excellence, and efficient service for its customers. In my opinion, these investments have been prudently incurred and are intended to ensure adequate and reliable electric service to DENC's retail customers in North Carolina.

Q. Please highlight some key ways DENC continues to improve the service provided to its North Carolina customers.

A. The mission of DENC is to provide all of its customers with the service they expect and deserve. The Company continues to achieve excellence in customer service by offering innovative solutions in response to customer expectations, which includes leveraging technology to perform quick, seamless transactions with the Company. As such, the Company is focused on providing a positive experience for customers as a whole by expanding web-based self-service and interactive options, while also being responsive to customers' more complex requests through first call resolution. In 2023, the

Company implemented a new customer information platform presenting customers with a modern and informative customer portal experience. This new platform will allow customers to view and pay bills and enroll in programs such as autopay and paperless billing, among other enhancements. We also made numerous enhancements to our customer contact center to provide customers with additional and convenient self-service options. Further, we began designing a new customer bill to improve bill comprehension and bill clarity, which is expected to be available to customers in late 2024. In addition, as discussed further by Company Witness Fields, DENC is working to install approximately 127,000 smart meters in North Carolina. This Advanced Metering Infrastructure ("AMI") allows customers to receive more detailed energy usage and permits them to take control of how and when they use energy. The Company is currently deploying AMI in the Outer Banks, Elizabeth City, and Williamston, and is starting to deploy AMI in Ahoskie and Roanoke Rapids.

In 2023, DENC's customers visited DominionEnergy.com approximately 260,000 times, which represents an increase of 15% from the previous year. DENC also promotes social media interactions with its customers through Facebook, Instagram, LinkedIn, and X. Social media channels offer customers an alternative way to reach the Company, for example to inquire about outages, and allow the Company to quickly communicate with large segments of customers at one time. DENC also publishes messages on social media that educate customers on important issues such as energy conservation, service reliability, safety, community involvement, and how to report and check outage status.

Q. Has the Company been recognized for its operations and performance?

A. Yes. Since the 2019 Rate Case, the Company has continued to receive recognition in the areas of emergency response (EEI Emergency Response Awards in 2021 and 2022), safety (Southeast Energy Exchange Total Company Safety Award in 2021), customer service (2022 EEI National Key Account Award for Outstanding Customer Engagement, 2021 Escalent Most Trusted Business Partner Utility), and technical innovation (2022 EPRI Technology Transfer Awards, which recognize contributions to projects to improve grid planning and reliability).

Q. What other recognitions has Dominion Energy received?

A. Dominion Energy received a number of recognitions during 2023 that demonstrate our commitment to being a good corporate citizen. These include recognition among Forbes America's Best Large Employers, Forbes – America's Best Employers for Women, and Site Selection Magazine's Top Utilities in Economic Development. Several recognitions received by Dominion demonstrate our strong commitment to military veterans. These include Military Friendly's "Military Friendly" Designation, and routine rankings among the top utilities by *Military Times Edge* as "Best for Vets" for the energy sector, and recognition as one of the top "Military-Friendly Employers" and "Spouse-Friendly Employers" in the U.S. by *GI Jobs*. In addition, Dominion was recognized as one of Forbes' "Best Employers for

Diversity" and "Best Employers for Women" in 2023, as well as a top supporter of Historically Black Colleges and Universities.

Q. Please expand on the Company's commitment to the communities it serves.

A. The Company and Dominion Energy believe that it is important for the local utility to be a contributor to, and an active participant in, the communities it serves.

The Company's EnergyShare program and its partnership with the Operation Fan Heat Relief program exemplify DENC's commitment to the communities it serves. EnergyShare helps customers experiencing a financial hardship pay their energy bills for any type of heating source (wood, oil, natural gas, propane, kerosene, and electric), particularly those who are lower income. Operation Fan Heat Relief provides fans and/or air conditioners to older adults and adults living with disabilities to help them stay cool. From 2019-2023, approximately $3.5 million was donated through EnergyShare and Operation Fan Heat Relief programs, helping approximately 10,000 individuals and families with their heating and cooling needs in DENC's service area. In particular, during the COVID-19 pandemic, the Company increased its EnergyShare contributions in North Carolina from $750,000 to $2.075 million.

Additionally, over the past three years, the Company and the Dominion Foundation have awarded over $376,325 in grants to various North Carolina organizations, schools and universities, food banks and other disaster relief funds. DENC employees and retirees donated more than 1,275 hours of volunteer service to their communities in North Carolina.

We are not only committed to contribute to the communities we serve, but also to demonstrate commitment to principles that reflect important public policy priorities, including diversity, equity, and inclusion ("DE&I") and environmental justice. To foster a more inclusive workforce, we reinforce and promote our desired workplace culture through, among other things, incorporating DE&I principles into our talent acquisition strategies, developing and executing leadership and employee training, implementing actionable ideas generated from our employee engagement surveys, and by supporting the growth, success, and impact of our employee resource groups. This strategy adds another method to support meeting community needs, better understand customer concerns, and align focus areas that may otherwise be overlooked or unknown. The Company has also been intentional in its focus on hiring diverse talent, with a desire to have our workforce reflect the communities in which we serve.

We are continuing to enhance our strategic partnerships by leveraging relationships with community partners and continuing to build out additional workforce development and diverse talent pipeline programs. These efforts include continued partnerships with organizations such as the Center for Energy Workforce Development, North American Building Trades Union, National Society of Black Engineers, and Society of Women Engineers. They also include holding career fairs during 2023 at NC State, NC A&T, and Nash Community College. In addition, we continue to identify top military service members, veterans, and their spouses whose values, work ethic, experience, and skills align with our career opportunities.

In the area of environmental justice, the Company abides by its policy, which commits to listening, considering, and responding to the concerns of all stakeholders in the process of siting and operating energy infrastructure. The Company's policy calls on project development teams to implement environmental justice reviews regardless of whether doing so is required for permitting or other regulatory approvals. We have established an environmental justice review process for evaluating specific projects and programs that implicate environmental justice concerns, and we present the results of these project-specific review processes in relevant proceedings before the Commission. The Company also includes and encourages feedback from a variety of community advocates during these reviews, such as through the Environmental Justice Advisory Council.

IV. PROPOSED ACCOUNTING AND TARIFF CHANGES

Q. Is the Company proposing any new accounting measures in this case?

A. Yes. In addition to other accounting measures addressed by Company Witnesses McLeod and Lee, DENC is also requesting Commission approval to defer potential future benefits from nuclear production tax credits ("NPTCs") pursuant to the 2022 Inflation Reduction Act ("IRA") to a regulatory liability account to be addressed in a future rate case. Deferral of any such benefits the Company receives will benefit customers by reducing the Company's cost of service and revenue requirement in future rate cases.

Witnesses McLeod and Lee also present the Company's proposals to begin recognizing for ratemaking purposes Asset Retirement Obligation ("ARO") costs other than those related to nuclear decommissioning and CCR remediation in the manner that these AROs are recognized for financial accounting purposes and to transition from amortizing CCR expenditures through deferral to incorporating an ongoing annual level of CCR remediation expenses in the Company's cost of service.

Q. Is the Company proposing any significant changes to its rate offerings or terms and conditions of service?

A. Yes. Company Witness C. Alan Givens discusses DENC's proposed new experimental small general service electric vehicle rate schedule, designated Schedule SGS-EV, to address, promote, and incentivize third party development and investment in electric vehicle ("EV") charging. Company Witness Christopher C. Hewett presents the Company's proposed residential time of use ("TOU") rate schedule, which is intended to improve the accuracy of price signals and alignment between customer charges and usage behaviors. Finally, Company Witness Jerri A. Brooks presents proposed revisions to the Company's "line extension plan" or "LEP" portion of our Terms and

Conditions and Witness Givens presents other proposed changes to the Terms and Conditions of Service.

V. PROPOSED RATE ADJUSTMENTS

Q. Will you please summarize the proposed rate adjustments presented in the Company's Application?

A. The Company's Application and pre-filed testimony request and support an incremental base non-fuel revenue requirement of approximately $56.6 million. Company Witness McLeod provides more detailed information and support for the Company's requested base non-fuel revenue requirement. As Company Witnesses Jeffrey D. Matzen and Christopher C. Hewett describe, the Company also expects reductions in the base component of fuel and projected 2025 fuel factor of approximately $30-40 million.

The Company is, as always, committed to the economic vitality of its service territory and recognizes the importance of delivering highly reliable power to industrial customers at a competitive cost. As Company Witness C. Alan Givens describes, the Company projects that the net effect of the combined adjustments to the Company's rates on November 1, 2024, including the non-fuel base rate increase and the projected fuel decrease expected in the 2024 fuel proceeding, will be an overall rate decrease of approximately 3% compared to rates currently in effect, from $133.11 to $128.93, to 12.89 c/kWh. After the proposed base rate increase, DENC's average rates will remain very competitive with the average rates for investor-owned utilities in the South Atlantic region, which as of December 2023, the most recent information available, were 11.91 c/kWh overall or 14.24 c/kWh for residential rates. The Company's proposed rates compare even more favorably with national average rates of 12.41 c/kWh overall or 15.73 c/kWh for residential rates.

VI. CONCLUSION

Q. Please introduce the Company's other witnesses who are filing testimony in support of the Application.

A. The Company is presenting the following additional witnesses:

- Richard M. Davis, Jr., General Manager, Corporate Finance and Assistant Treasurer for the Company, presents DENC's capital structure and explains why the Company must attract sufficient debt and equity capital at a reasonable cost to meet DENC's customers' current and future demand for electricity.
- Jennifer E. Nelson, Assistant Vice President, Concentric Energy Advisors, testifies as to her assessment of the Company's cost of common equity, reasonableness of the Company's requested capital structure, and the ROE that is appropriate in this case.
- Jeffrey G. Miscikowski, Vice President, Project Construction for Dominion Energy Services, Inc., discusses the Company's major investments since the 2019 Rate Case in CCR remediation, solar, battery storage, and offshore wind, and fossil and nuclear fleet maintenance, and describes the benefits to DENC's customers of those

investments.

- Kevin L. Fields, Director, Electric Transmission Project Management Organization, Dominion Energy Technical Solutions, Inc., discusses the Company's major investments in its transmission and North Carolina distribution electric system since the 2019 Rate Case and describes the benefits to DENC's customers from those investments.
- Robert E. Miller, Manager, Regulation for the Company, supports the cost of service studies filed in support of the Application, addresses the Company's proposed allocation methodology for production and transmission plant, and certain alternative allocation methodologies. Mr. Miller also addresses the allocation of distribution plant and related expenses.
- Paul M. McLeod, Director, Regulatory Accounting for the Company and Christopher J. Lee, Manager, Regulatory Accounting for the Company, present the calculation of the increase in the Company's revenues required in this case to provide the Company with the opportunity to recover its costs of providing service and to earn a fair rate of return on common equity, based on an adjusted 2023 test year. Messers. McLeod and Lee also support the proposed adjustments to cost of service and discuss the Company's request for approval to defer benefits from nuclear production tax credits pursuant to the Inflation Reduction Act.

- C. Alan Givens, Manager, Regulation Rate Design for the Company, discusses the Company's proposed apportionment of the non-fuel base rate revenue requirement increase among the customers classes and presents the Company's proposed new experimental small generation service time of use rate schedule to address, promote, and incentivize third party development and investment in electric vehicle charging. Mr. Givens also addresses how the proposed non-fuel base, base fuel, the projected EMF fuel adjustments will impact customers' rates.
- Jeffrey D. Matzen, Manager, Strategic Planning for the Company, presents the Company's adjusted total system fuel expenses, which are used to calculate the base fuel rate. Mr. Matzen also provides an estimate of the system fuel expense for July 1, 2023-June 30, 2024, and an estimate of the deferred fuel balance as of June 30, 2024.
- Christopher C. Hewett, Regulatory Specialist for the Company, presents the Company's updated base fuel rate and provides a projection of that rate and the EMF projected for DENC's August 2024 fuel proceeding.
- Jerri A. Brooks, Customer Contracts Specialist for the Company, testifies in support of DENC's proposed revisions to Section XXII of its Terms and Conditions, related to Electric Line Extensions and Installations.

Q. Do you have any final remarks on the Company's Application?

A. Yes. As I stated at the beginning of my testimony, the Company is committed to meeting its obligation to provide safe, reliable, and cost-effective electric service and has consistently demonstrated that commitment within its North Carolina service territory. DENC is focused on making prudent investments in critical infrastructure and operating efficiency to meet its customers' need for safe, reliable, cost-effective, and environmentally responsible electric utility service 24 hours a day, 365 days of the year. DENC's capital investments since the 2019 Rate Case have enabled it to continue to ensure reliability and efficiency of service to the Company's North Carolina customers, as well as to comply with environmental requirements, and DENC continues to invest in and operate its system to meet its customers' needs. The Company therefore requests the Commission's approval of its Application in this proceeding.

Q. Does this conclude your direct testimony?

A. Yes.

APPENDIX A

**BACKGROUND AND QUALIFICATIONS
OF
EDWARD H. BAINE**

Edward H. "Ed" Baine is president – Dominion Energy North Carolina. He is responsible for all facets of the Company, a vertically integrated electric utility with generation. transmission and distribution assets that provides electric service to about 2.8 million customer accounts in northeastern North Carolina and Virginia.

Mr. Baine joined the company in 1995 as an associate engineer and since has held numerous engineering, operational and management positions. He was promoted to vice president – Shared Services in 2009 and became vice president – Power Generation Merchant Operations in 2012. He became vice president – Power Generation System Operations in 2013 and senior vice president – Transmission & Customer Service in 2015. In 2016, he was named senior vice president – Distribution, Power Delivery Group. He was named senior vice president – Power Delivery, Dominion Energy Virginia in 2019 and assumed his current position in October 2020.

Mr. Baine is a member of the boards of directors of the Dominion Energy Credit Union, Chamber RVA, and Venture Richmond. In addition, he serves on the board of visitors at Virginia Tech and the boards of directors of the Southeastern Electric Exchange, the Virginia Tech Athletic Fund, MEGA Mentors, VA Learns, as well as on the EPRI Research Advisory committee and the Virginia American Revolution 250 Commission.

Mr. Baine earned his bachelor's degree in electrical engineering from Virginia Tech and completed the advanced management program at Duke University's Fuqua School of Business. He is a registered professional engineer in Virginia.

DIRECT TESTMONY
OF
RICHARD M. DAVIS, JR.
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 694

Q. Please state your name, position of employment, and business address.

A. My name is Richard M. Davis, Jr. I am General Manager, Corporate Finance; Assistant Treasurer for Virginia Electric and Power Company, which does business in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company"). My business address is 120 Tredegar Street, Richmond, Virginia 23219.

Q. Please describe your areas of responsibility within the Company.

A. I am responsible for the execution, documentation, monitoring, compliance and reporting of all financing transactions carried out in the public and private capital and bank markets for Dominion Energy and its subsidiaries (including the Company). A statement of my background and qualifications is attached as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes. I provided direct and supplemental testimony to the Commission in the Company's previous rate case in Docket No. E-22, Sub 562 ("2019 Rate Case").

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

A. My testimony presents DENC's adjusted year-end regulated capital structure, calculated in line with methodology consistent with prior approved rate case filings with the North Carolina Utilities Commission ("Commission"), as of December 31, 2023, adjusted on a proforma basis to include an early January 2024 long-term debt issuance, and the Company's proposed weighted average cost of capital. I also discuss the Company's credit profile and the importance of maintaining strong credit ratings as it continues to make significant capital investments in its generation, transmission, and distributions assets for the benefit of North Carolina customers. As Company Witness Edward H. Baine explains in his Direct Testimony, this includes investments in offshore wind and solar generation facilities, subsequent license renewals for the existing nuclear fleet, new and upgraded transmission lines, and new distribution substations. In total, the Company has made over $22.5 billion of capital investments in the five years since the prior rate case to improve reliability and environmental sustainability of the system and support load growth. Finally, I address how the Company's significant capital needs should be considered in setting DENC's overall cost of capital and proposed return on equity ("ROE") in order to reach a just and reasonable ratemaking result that fairly balances the Company's capital requirements with the interests of its customers.

Q. Will you introduce exhibits as part of your testimony?

A. Yes. I am sponsoring Company Exhibit RMD-1, Schedule 1 of 1, which presents the Company's adjusted year-end regulatory capital structure as of December 31, 2023. This schedule is in accordance with the methodology consistent with prior approved rate case filings. The schedule also reflects a proforma adjustment for long-term debt issued in January 2024. This exhibit was prepared under my supervision and direction, and is accurate and complete to the best of my knowledge and belief.

Q. Please describe the Company's proposed capital structure to be used in this proceeding.

A. The Company's ratemaking capital structure presented for this proceeding is based upon DENC's actual experience as of December 31, 2023, and includes a proforma adjustment for long-term debt issued in January 2024. The capital structure presented follows methodology consistent with prior approved rate case filings for reporting capital structure and includes adjustments, including, for example, the Commission's long-standing adjustment to exclude short-term debt from the capital structure calculations. As shown on my Schedule 1, the long-term debt component of DENC's December 31, 2023, capital structure is 46.15%, and the equity component is 53.85%.

Q. Why is the Company's adjusted capital structure as of December 31, 2023, appropriate for use in this proceeding?

A. The Company's December 31, 2023, capital structure is appropriate because it fairly reflects DENC's actual operating experience and is also consistent with the Company's year-end capital structure for the past two years. The proforma adjustment considers the $1 billion long-term debt offering that was completed in early January 2024. Since the Commission most recently set DENC's base rates in Docket No. E-22, Sub 562 ("2019 Rate Case"), the Company's year-end equity component was 53.61% as of December 31, 2019, 52.73% as of December 31, 2020, 54.11% as of December 31, 2021, and 52.63% for the year ending December 31, 2022. DENC's adjusted December 31, 2023, equity component of 53.85% is very similar to this recent experience.

Q. What is the Company's proposed weighted-average cost of capital and what cost rates did you attribute to each component of the Company's capital structure?

A. As shown on my Schedule 1, the Company's weighted average cost of capital is 7.66%, which is composed of a long-term debt cost rate of 4.24% and a cost of common equity rate of 10.60%. The long-term debt cost rate is based upon debt issued, via the capital markets, and still outstanding at December 31, 2023, in addition to the proforma adjustment to consider the January 2024 long-term debt issuance. It is worth noting the increased rates since the most recent rate case are largely due to rate hikes posed by the Federal Reserve to manage historically high levels of inflation in the past few years. The cost of common equity cost rate is supported by Company Witness Jennifer E. Nelson in her testimony and supporting schedules.

Q. What capital needs do you foresee for the Company?

A. Since the 2019 Rate Case, the Company has made and continues to make significant investments to maintain and improve the sustainability and reliability of the service it provides to its North Carolina customers and to comply with federal and state environmental obligations. As Company Witness Baine explains in more detail, the Company plans continued capital investments approximating $35.5 billion during the period 2025-2029. All told, the significant capital investment projects planned over the next few years will strengthen the Company's entire interconnected system as well as provide additional renewable resources, thus benefitting its customers in North Carolina with a more sustainable, stable, and reliable system for years to come. In addition, the Company will need to maintain reasonable access to financing in the capital markets in order to fund these significant investments.

Q. Please describe the Company's plan for financing this substantial infrastructure investment program over the next few years.

A. The Company's first step when undertaking a significant infrastructure growth and capital expenditure program is to develop a financing plan that accommodates the capital needs while also managing its investment-grade credit profile with a focus on maintaining access to a wide range of financial markets on reasonable terms. Much of this effort relates to maintaining credit metrics that are supportive of DENC's target credit ratings, which maintains the Company's access to markets on reasonable terms.

The Company's request in this proceeding is based on a balance of both debt and common equity that has historically supported and, the Company believes, will continue to support its credit ratings going forward. In addition, the Company's request will enable it to access several markets, under a wide range of economic environments, on reasonable terms and conditions. This market access is critical in light of the ongoing infrastructure capital expenditure program that will be necessary to meet the Company's public service obligations in North Carolina and throughout DENC's system. The Company must compete for funding in the capital markets against alternative investment opportunities. To do so, the Company's balance sheet—and more importantly—its cash coverage of its total debt principal obligations must be supportive of strong credit ratings to assure access to capital markets in both stable and volatile environments.

DENC's cash coverage is measured primarily by the ratio of funds from operations ("FFO") to total debt ("FFO/Debt"). This critical metric assesses the Company's ability to meet its debt obligations for the timely repayment of principal and interest. Thus, while the more familiar total debt to total capitalization ratio ("Debt/Cap") as displayed in a company's capital structure statement is important, it is not the principal focus of DENC's decisions regarding financing needs for the Company. Since recovery of construction costs is not concurrent with the cash expenditures (a portion of which is of course met through borrowings) FFO/Debt will be impacted during any construction period. In the Company's case, this metric will be stressed due to the large and lengthy infrastructure build program that has been ongoing for some time and that is expected to continue for the next several years.

Q. Please explain how the Company's financing plans are developed.

A. In developing its financing plans, DENC seeks to balance its financing needs in order to fund its operations to meet its public service obligations while achieving its ratings objectives. With this guiding objective in mind, the Company focuses primarily on FFO/Debt to craft a financing plan that produces credit metrics that it believes supports its target ratings. The focus on these FFO measures over time means that the Debt/Cap ratio is more of a result, rather than the focal point, of the process of creating a financing plan. This is because the amount of equity and debt needed over time is not based on a pre-specified debt to total capital ratio, but is rather driven by the impact of those debt and equity amounts on the FFO measures. The overall intent of this approach of viewing these FFO metrics on a forward-looking basis is to further DENC's goal of achieving its target ratings in a deliberate and measurable manner.

Q. Are other electric utilities facing this same need for access to capital to undertake capital expansion programs?

A. Yes, many utilities are similarly facing unprecedented capital needs as they invest in their systems to continue to provide sustainable and reliable utility service. These upgrades are needed for several reasons, including continued increases in peak demand nationally, aging electric utility infrastructure, new environmental regulations, changing customer needs, and electric grid security requirements. Many of these investments do not expand generation capacity, but they do enhance the ability to provide reliable service and add another layer to the industry's demand for capital. The need to raise funds for these capital upgrades and expansion across the entire electric utility sector results in increased competition for investor dollars both within the electric utility sector as well as against other market sectors (*e.g.*, financials, health care, or other corporates) with robust and increasing capital requirements.

In its annual presentation to the investment community delivered in February 2024, Edison Electric Institute ("EEI") estimated that over forty-percent of U.S. power generation now comes from carbon-free sources like nuclear and renewables, including hydropower, wind, and solar. As with the construction of new power plants, all of these developments require utility investments in transmission and distribution infrastructure to deliver power from these new resources to customer load. In its report, EEI also noted that its member companies will spend in excess of $150 billion per year to build smarter, cleaner, stronger, and more secure energy infrastructure. Financing the industry's ongoing planned significant capital investments will result in competition for investor funding. The higher rated utilities will fare best in this scenario with lower borrowing costs and more reliable access to the capital markets, no matter the market conditions.

Q. How do the rating agencies view regulatory outcomes in their assessments of a company's creditworthiness?

A. In order to access capital as needed, the Company must continuously maintain a strong credit profile, balance sheet, and cash flow coverages to ensure that cash flows are sufficient to service debt and to realize adequate returns on equity. To achieve these goals, the Company needs proper rate determinations and related supportive regulatory decisions, including from this Commission. In its current rating methodology, Standard and Poor's ("S&P") notes that a supportive legislative and regulatory framework is a critical aspect that underlies regulated utilities' creditworthiness because "it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance." S&P also names "Four Pillars" that provide the foundation of regulatory support. These four pillars include regulatory stability, tariff-setting procedures and design, financial stability, and regulatory independence. S&P notes that the utility's business strategy and the ability to manage the tariff-setting process are also important aspects in the overall regulatory assessment. As Moody's Investors Service ("Moody's") noted in a report on its ratings methodology for utilities published in June 2017 it uses four "Broad Rating Factors" in its ratings analysis. The first factor, "Regulatory Framework," carries a 25% weight, and is weighted evenly into two sub-factors, "Legislative and Judicial Underpinnings of the Regulatory Framework" and "Consistency and Predictability of Regulation." The second broad factor, "Ability to Recover

Costs and Earn Returns," is also given a 25% weight. As with the first broad factor, it is split evenly into two sub-factors, "Timeliness of Recovery of Operating and Capital Costs" and "Sufficiency of Rates and Returns." These first two broad functions carry an overall sum of 50% and are directly related to regulatory environment and regulatory supportiveness. The next factor, "Diversification," is split evenly between two sub-factors, "Market Position" and "Generation and Fuel Diversity." The remaining 40% weight is spread across four other factors, mainly financial metrics, only one of which, "Cash Flow from Operations before Working Capital to Debt," is given a greater weight (15%) than any of the sub-factor weights for the first two broad rating factors. Clearly, regulatory support will continue to assume increased importance as the Company proceeds with its infrastructure plans over the next several years.

Equity markets are very attuned to the Company's achieved financial results and to regulatory commission decisions. These markets will respond immediately when the Company's prospects for future returns are perceived to have diminished. A decision from this Commission that sets a return lower than what the market views as adequate would lead analysts and investors to conclude that this shortfall could be the norm of the regulatory process and make it more difficult for DENC to achieve its ratings targets and secure the capital needed to carry out the significant investments that will be needed in the next few years to continue to meet customer demand. This in turn could lead to more expensive financing costs for the Company, and ultimately, customers.

Q. What are the Company's current credit ratings?

A. Virginia Electric and Power Company's outstanding debt is rated by Fitch Ratings ("Fitch"), Moody's, and S&P. As of the filing date of this case, the Company's senior unsecured debt carries the following strong investment grade ratings: A by Fitch, A2 by Moody's, and BBB+ by S&P, with stable outlook at Fitch and negative outlooks at Moody's and S&P. The ratings on the Company's commercial paper program are F-2 by Fitch, P-1 by Moody's, and A-2 by S&P.

Q. How were the Company's current target credit ratings determined?

A. DENC's target credit ratings are the result of the ongoing, detailed, Company-specific dialogue with the credit analysts and policy makers at each of the rating agencies on the appropriate level of its credit metrics. While published credit metrics and credit commentary can serve as general benchmarks or provide insight into how the agencies may view a topic from a broad policy perspective, DENC does not rely on such publications to establish its targets. Instead, the Company engages in direct dialogue with the analysts that are responsible for covering the Company. The credit analysts then review, analyze, and recommend actions on the Company's ratings to their respective rating committees, which in turn ultimately determine the rating for the Company.

As I have discussed above, the Company continues to operate in a climate of need for financing for significant amounts of capital expenditures, and in that climate it will be viewed more positively by rating agencies if it is operating from a position of strength with regard to its credit profile. The targeted rating for the Company of "single A" represents a very strong investment grade credit rating.

Q. What are the Company's current target credit ratios?

A. The Company does not target specific credit ratios; rather, it focuses on achieving a target credit rating, which is currently "single-A." Each rating agency has unique criteria for achieving this target rating, and these criteria include numerous quantitative and qualitative factors. The Company is in frequent dialogue with Moody's, S&P, and Fitch and closely monitors how well historical and forecasted results align with the criteria for the single-A rating level.

Q. Please describe how DENC's significant capital needs should be considered in determining the Company's overall cost of capital and ROE.

A. My testimony highlights the Company's significant and ongoing capital needs as well as the important and very real financial consequences that the Commission's capital attraction (*i.e.*, return) decisions can have in the capital markets and on the terms under which DENC can access those markets. The Company is requesting that the Commission authorize DENC's equity and debt capital needs at a level that assures confidence in the Company's financial soundness and that enables DENC to maintain and support its credit requirements and to raise the capital necessary—on favorable terms—to continue providing safe and reliable service to its customers.

As Company Witness Nelson's testimony demonstrates, the Company's current market cost of equity is in the range of 9.9% to 11.4%. Granting the Company an authorized return of 10.60% on common equity will ensure DENC's ability to compete in the capital markets and to raise equity and debt at reasonable rates. Additionally, authorizing the Company's requested return on common equity will allow DENC to carry out its responsibility to provide reliable service at an affordable cost and is fundamental to the Company's ability to maintain a strong credit profile. The ability to access the capital markets on reasonable terms will ultimately reduce DENC's borrowing cost for the benefit of its customers. Company Witness Nelson also addresses the impact of changing economic conditions in setting the Company's authorized return on equity.

Q. Do you have any final comments about your testimony?

A. The Company will continue to see increased competition for capital in the near future at the same time as it continues with the significant capital investment plan I have highlighted here and which is discussed more completely by Company Witness Nelson in her testimony. As discussed further by Company Witness Nelson, utility risk and capital costs have increased significantly since the Company's 2019 Rate Case and, under such circumstances, the financial strength and future earnings potential of regulated utility companies factor even more significantly into those companies' ability to compete for capital than is normally the case.

It is vitally important that DENC be able to achieve its targeted credit profile, which is based on the capital structure and cost of capital filed in this case, in order to access the capital markets on favorable economic terms and, as a result, be able to realize the significant capital investments needed over the course of the next few years to maintain and improve reliable service to its customers. Finally, the Company understands that the Commission must set just and reasonable rates, including the authorized ROE, in a way that balances the economic conditions facing DENC's customers with the Company's need to attract equity financing in order to continue providing safe and reliable service. In light of the Company's significant capital needs, I will close by stating that a financially sound utility with a strong credit profile is in the best interest of both the Company and its customers.

Q. Does this conclude your direct testimony?

A. Yes.

BACKGROUND AND QUALIFICATIONS
OF
RICHARD M. DAVIS, JR

Richard M. Davis, Jr. is the General Manager of Corporate Finance and Assistant Treasurer. He joined Dominion in April 2005 and was named to his current post in October 2023. Prior to his current role, Mr. Davis was most recently employed with BHE GT&S for 3 years serving as the Director-Treasury and Assistant Treasurer. In that role, he directed all aspects of the Treasury Department, including cash management, corporate finance and accounts payable for over 20 legal entities. Prior to returning to Dominion from BHE GT&S, Mr. Davis had nearly 16 years of experience in various accounting and finance roles, including as the Director-Strategic Risk Management and Director – Corporate Finance. In the Strategic Risk Management role, he was responsible for the oversight and facilitation of annual business segment risk assessments. These assessments provided executive management and the board the ability to identify, quantify and respond to the key risks of the business. The role also included significant involvement in the Investment Review Committee (IRC) process. In his Director-Corporate Finance and Assistant Treasurer role he had similar responsibilities to his current position. Prior to joining Dominion, Mr. Davis primarily worked in public accounting as an auditor serving various industries, including power and utilities. Mr. Davis serves on the board of directors for The Faison Center – a Richmond-based non-profit educational and treatment center serving individuals and families impacted by autism spectrum disorder and other developmental disabilities. Mr. Davis earned a bachelor's and master's degree in accounting from Wake Forest University and is a Certified Public Accountant in the Commonwealth of Virginia.

VIRGINIA ELECTRIC AND POWER COMPANY

Cost of Capital and Capital Structure

Adjusted December 31, 2023 Balances with Proposed ROE

Description	2023 Amount	2023 Percent	EOP 2023 Annualized Cost Rate	2023 Weighted Cost
Total Long-Term Debt	$18,477,656,776	46.151%	4.239%	1.956%
Total Debt	18,477,656,776	46.151%	4.239%	1.956%
Common Equity:				
Common Stock & Other Paid-in Capital	10,100,249,537	25.227%		
Retained Earnings	11,459,545,121	28.622%		
Total Common Equity	21,559,794,658	53.849%	10.600%	5.708%
Total Capitalization	$40,037,451,435	100.000%		7.664%

1) Actual December 31, 2023 long-term debt has been adjusted to reflect the impacts of a $1 billion debt offering that was completed on January 8th, 2024 as though it had occurred on December 31, 2023.

DOCKET NO. E-22, SUB 694

DIRECT TESTIMONY OF

JENNIFER E. NELSON

ON BEHALF OF

DOMINION ENERGY NORTH CAROLINA

March 28, 2024

TABLE OF CONTENTS

I. INTRODUCTION & WITNESS IDENTIFICATION 1

II. PURPOSE AND OVERVIEW OF TESTIMONY 3

III. COST OF EQUITY ESTIMATION 7

A. Regulatory Guidelines and Principles 7

B. Proxy Group Selection 12

C. Cost of Equity Models 17

IV. BUSINESS RISKS AND OTHER CONSIDERATIONS 38

A. Capital Expenditures, Regulatory Environment, and Capital Access 39

V. ECONOMIC CONDITIONS IN NORTH CAROLINA 50

VI. CAPITAL STRUCTURE 61

VII. CAPITAL MARKET ENVIRONMENT 64

VIII. CONCLUSIONS 74

LIST OF EXHIBITS

Exhibit JEN-1:	Résumé and Testimony Listing of Jennifer E. Nelson
Exhibit JEN-2:	Constant Growth DCF Results
Exhibit JEN-3:	Quarterly Growth DCF Results
Exhibit JEN-4:	Expected Market Return Calculation
Exhibit JEN-5:	Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Exhibit JEN-6:	Bond Yield Plus Risk Premium Analysis
Exhibit JEN-7:	Capital Expenditure Analysis
Exhibit JEN-8:	Regulatory Risk
Exhibit JEN-9:	Capital Structure

I. INTRODUCTION & WITNESS IDENTIFICATION

Q. Please state your name, affiliation, and business address.

A. My name is Jennifer E. Nelson. I am an Assistant Vice President at Concentric Energy Advisors ("Concentric"). Concentric is a management consulting and economic advisory firm that specializes in the North American energy and water industries. Based in Marlborough, Massachusetts and Washington, D.C., Concentric specializes in regulatory and litigation support, financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts, 01752.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this direct testimony ("Direct Testimony") before the North Carolina Utilities Commission ("Commission") on behalf of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina ("DENC" or the "Company").

Q. Please describe your professional experience and educational background.

A. I have fifteen years of experience in the energy industry, having served as a consultant and energy/regulatory economist for state government agencies. Since 2013, I have provided consulting services to utility and regulated energy clients on a range of financial and regulatory issues including cost of capital, ratemaking policy, and regulatory strategy issues. Prior to consulting, I was a staff economist at the Massachusetts Department of Public Utilities, and a petroleum economist for the State of Alaska. I completed utility regulatory training offered by New Mexico State University's Center for Public Utilities and have earned the Certified Rate of Return Analyst designation from the Society of Utility and Regulatory Financial Analysts. I hold a Bachelor's degree in Business Economics from Bentley University and a Master's degree in Resource and Applied Economics from the University of Alaska. A summary of my professional and educational background, including a list of my testimony filed before regulatory commissions, is included as Exhibit JEN-1.

Q. Have you previously submitted testimony to the Commission?

A. Yes, I filed cost of capital testimony on behalf of Public Service Company of North Carolina in Docket No. G-5, Sub 632. Additionally, I have filed testimony before regulatory commissions in Arkansas, Florida, Kentucky, Maine, Montana, New Hampshire, New Mexico, Ohio, Oklahoma, Oregon, South Carolina, Texas, Utah, West Virginia, and Wyoming. During my time as a consultant, I have supported expert witness testimony regarding the cost of capital (*i.e.*, Return on Equity ("ROE") and capital structure) in more than 100 proceedings filed before numerous U.S. state regulatory commissions and the Federal Energy Regulatory Commission ("FERC").

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to present evidence and provide the Commission with a recommendation regarding the Company's ROE to be used for ratemaking purposes, and to assess the reasonableness of the Company's requested capital structure. My conclusions are supported by the analyses presented in Exhibit JEN-2 through Exhibit JEN-9, which have been prepared by me or those under my direction.

Q. What are your conclusions regarding the appropriate Cost of Equity[1] and the reasonableness of the capital structure for the Company?

A. Based on my analyses of three widely used market-based financial models, the Company's risk profile, and the current capital market environment, I conclude that a range of 9.90 percent to 11.40 percent reflects investors' required return for an equity investment in DENC. Within that range, I recommend an ROE of 10.60 percent.

As to the Company's capital structure, I conclude its requested capital structure consisting of 53.85 percent common equity and 46.15 percent long-term debt is consistent with the proportions of long-term capital that finance the regulated electric operations of the proxy group and is therefore reasonable. DENC's

1 Throughout my testimony, I use the terms "Cost of Equity" and "ROE" interchangeably.

requested Weighted Average Cost of Capital ("WACC") is shown in Figure 1 below.

Figure 1: Weighted Average Cost of Capital

	% of Capital	Cost (%)	Weighted Cost
Long-Term Debt	46.15%	4.239%	1.96%
Common Equity	53.85%	10.60%	5.70%
Total	100.00%		7.66%

Q. Please provide a brief overview of the analyses that led to your ROE recommendation.

A. My recommendation was developed using three widely accepted financial modeling approaches applied to a proxy group of 18 electric utility companies: (1) the constant growth and quarterly forms of the Discounted Cash Flow ("DCF") model; (2) the traditional and empirical forms of the Capital Asset Pricing Model ("CAPM"); and (3) the Bond Yield Plus Risk Premium approach. The results of those analytical approaches are summarized in Figure 2 below.

Figure 2: Summary of Results[2]

Constant Growth DCF	**Low**	**Mean**	**High**
30-Day Average	8.70%	9.86%	10.99%
90-Day Average	8.77%	9.94%	11.05%
180-Day Average	8.59%	9.78%	10.89%
Quarterly Growth DCF	**Low**	**Mean**	**High**
30-Day Average	8.85%	10.05%	11.21%
90-Day Average	8.92%	10.13%	11.28%
180-Day Average	8.74%	9.95%	11.11%
CAPM		**Current 30-Year Treasury Yield (4.19%)**	**Projected 30-Year Treasury Yield (4.14%)**
Long-Term Historical Average Market Return		11.26%	11.25%
DCF-based Expected Market Return		13.27%	13.27%
Empirical CAPM		**Current 30-Year Treasury Yield (4.19%)**	**Projected 30-Year Treasury Yield (4.14%)**
Long-Term Historical Average Market Return		11.45%	11.44%
DCF-based Expected Market Return		13.52%	13.51%
Bond Yield Plus Risk Premium			
Current 30-Year Treasury Yield (4.19%)		10.10%	
Projected 30-Year Treasury Yield (4.14%)		10.08%	
Mean		10.64%	
Median		10.51%	
Average of the mean and median		10.58%	

2 *See,* Exhibit JEN-2 to Exhibit JEN-6. Data as of January 31, 2024. DCF and CAPM estimates reflect the average of the proxy group mean and median ROE estimates.

Q. How did you determine your recommendation from the results summarized above?

A. The Cost of Equity is an opportunity cost that cannot be precisely quantified. Therefore, it must be estimated using various financial models. Each of the ROE-estimation models is subject to limiting assumptions and each provides a different perspective on investors' return requirements under varying market conditions. The use of multiple financial models, therefore, enables a more robust and comprehensive assessment of the Cost of Equity instead of relying on one specific estimation model.

After reviewing the model results shown above in Figure 2, I assessed the Company's risk profile relative to a group of proxy companies. As explained in more detail throughout my testimony, my recommendation considers: (1) the Company's planned capital expenditure program and ongoing need to access capital; (2) the regulatory environment in which DENC operates; (3) the economic conditions in North Carolina; (4) the financial risk associated with the Company's capital structure; and (5) the capital market environment. Although I do not make an explicit adjustment for these risks, I considered them in determining my ultimate recommendation. Based on all these factors, I concluded that an ROE at the approximate midpoint of my recommended range, and roughly equal to the average of the mean and median of the model results shown in Figure 2 above (10.60 percent) is reasonable.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my Direct Testimony is organized as follows:

- Section III – Summarizes the regulatory guidelines and principles relevant to the cost of capital estimation in regulatory proceedings, explains the selection of the proxy group used to develop my analytical results, and describes the analyses on which my ROE determination is based;
- Section IV – Discusses the Company's business risk profile relative to the proxy group that affect its Cost of Equity;
- Section V – Reviews the current economic conditions in North Carolina and the implication on the Cost of Equity;
- Section VI – Provides an assessment of the Company's requested capital structure;
- Section VII – Reviews the current capital market conditions and the implication on the Cost of Equity; and
- Section VIII – Summarizes my conclusions.

III. COST OF EQUITY ESTIMATION

A. Regulatory Guidelines and Principles

Q. Before addressing your Cost of Equity analyses, please explain the cost of capital conceptually.

A. The cost of capital is the return that investors require to commit capital to a firm. Investors will provide capital investment to a firm only if the return they expect is equal to, or greater than, the return they require to accept the risk of investing capital in the firm. Simply, the cost of capital is the expected rate of return prevailing in the capital markets on alternative investments of similar risk.[3] Conceptually, the cost of capital is: (1) forward looking and reflects an expected rate of return; (2) an opportunity cost; (3) determined in the capital markets, and (4) dependent on, and proportional to, the risk of the investment.[4]

Because the Cost of Equity is expectational and premised on the principle of opportunity costs, it cannot be precisely quantified. Instead, it must be estimated by applying market data to various financial models that are simplified representations of investor behavior and expectations. Moreover, equity investors have a subordinate claim to cash flows owed to debt investments and other claims; the uncertainty (or risk) associated with those residual cash flows determines the Cost of Equity. In the end, the Cost of Equity should reflect the return that investors require considering the subject company's risk profile and the returns available on comparable investments.

Q. Please summarize the guiding principles used in establishing the cost of capital for a regulated utility.

A. Public utility regulation is rooted in the principle that utilities receive a fair rate of return sufficient to attract the capital required to provide safe and reliable public utility service for customers at reasonable rates. The U.S. Supreme Court ("Supreme Court") established the guiding principles for establishing a fair rate of return for a public utility in two seminal cases: (1) *Bluefield Water Works*

---

3 Lawrence A. Kolbe, James A. Read, Jr., and George R. Hall, The Cost of Capital – Estimating the Rate of Return for Public Utilities, The MIT Press, Cambridge, MA, at 13 (1985).

4 Lawrence A. Kolbe, James A. Read, Jr., and George R. Hall, The Cost of Capital – Estimating the Rate of Return for Public Utilities, The MIT Press, Cambridge, MA, at 13 (1985).

and Improvement Co. v. Public Service Comm'n. ("*Bluefield*");[5] and (2) *Federal Power Comm'n v. Hope Natural Gas Co.* ("*Hope*").[6] In *Bluefield*, the Supreme Court stated:

> A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties.[7]

In *Hope*, the Supreme Court reiterated the three primary standards for a regulated rate of return:

> [Th]e return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[8]

In summary, the Supreme Court has recognized that the fair rate of return on equity should be: (1) commensurate with returns investors expect to earn on other investments of similar risk (the "comparable risk" standard); (2) sufficient to assure confidence in the company's financial integrity (the "financial

---

5 *See*, *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*. 262 U.S. 679, 692 (1923).

6 *See*, *Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).

7 *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*. 262 U.S. 679, 692 (1923).

8 *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

integrity" standard); and (3) adequate to maintain and support the company's credit and to attract capital (the "capital attraction" standard). Importantly, a fair and reasonable return satisfies all three of these standards.

Q. Has the Commission also looked to the *Hope* and *Bluefield* standards as guidance for setting rates?

A. Yes, it has. For example, in Docket No. E-7, Sub. 1026, the Commission noted that:

> First, there are, as the Commission noted in the DEP Rate Order, constitutional constraints upon the Commission's return on equity decision, established by the United States Supreme Court decisions in Bluefield Waterworks & Improvement Co., v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) (Bluefield), and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) (Hope):
>
> To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting an ROE, the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. State ex rel. Utilities Commission v. General Telephone Co. of the Southeast, 281 N.C. 318, 370, 189 S. E.2d 705, 757 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return declared" in Bluefield and Hope. Id.[9]

9 North Carolina Utilities Commission, Docket No. E-7, Sub 1026, *Order Granting General Rate Increase*, at 23 (September 24, 2013).

Based on those standards, the authorized ROE should provide the Company with a reasonable opportunity (which is not a guarantee) to earn a fair return and enable efficient access to external capital under a variety of market conditions.

Q. What are your conclusions regarding the regulatory principles pertaining to the cost of capital for a public utility?

A. The ratemaking process is based on the principle that a utility must have a reasonable opportunity to recover the return of, and the market-required return on, invested capital required to provide safe and reliable utility services. The outcome of the Commission's order in this case, therefore, should provide DENC with the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments having similar risks.

As explained in more detail in Section IV, the regulatory environment is one of the most important factors considered by both debt and equity investors in their assessments of risk. In that respect, the financial community carefully monitors the current and expected financial condition of utility companies, which is significantly influenced by the regulatory decisions and environment in which they operate. Therefore, the Commission's decision regarding the authorized ROE and capital structure in this proceeding will directly affect the Company's financial health and its ability to attract capital on reasonable terms.

B. Proxy Group Selection

Q. Why is it necessary to select a group of proxy companies to determine the Cost of Equity for DENC?

A. The Cost of Equity for a given enterprise depends on the risks attendant to the business in which the company is engaged. Because the ROE is a market-based concept, and DENC is not a separate entity with its own stock price, it is necessary to establish a group of companies that is both publicly traded and comparable to the Company in certain fundamental respects to serve as its "proxy" in the ROE estimation process. Even if the Company were a publicly traded entity, temporary short-term events could bias its market value during a given period. A significant benefit of using a proxy group is that it moderates the effects of anomalous, temporary events associated with any one company.

Q. Please provide a summary profile of DENC.

A. Virginia Electric and Power Company is a wholly owned subsidiary of Dominion Energy, Inc. ("DEI") and provides electric generation, transmission, and distribution services to approximately 2.75 million customers in Virginia and North Carolina, of which over 127,000 customers are in North Carolina.[10] For the twelve months ended December 31, 2023, the Company reported net operating income of $71.8 million and net plant of $1.51 billion for its North

10 NCUC Form E.S.-1 for the twelve months ended December 31, 2023, Schedule 8, at 1.

Carolina electric operations.[11] The current long-term issuer credit ratings for the Company and its parent are as follows:

Figure 3: DENC and DEI Issuer Credit Ratings and Outlook

	S&P	Moody's	Fitch
DEI	BBB+ (Outlook: Negative)	Baa2 (Outlook: Stable)	BBB+ (Outlook: Stable)
DENC	BBB+ (Outlook: Negative)	A2 (Outlook: Negative)	A- (Outlook: Stable)

Q. Does the fact that DENC is a wholly owned subsidiary of DEI affect its Cost of Equity?

A. No. The Cost of Equity depends on the risk of a firm's operations and the assets supporting those operations. In other words, the Cost of Equity depends on the *use* of capital, not on the *source* of capital. Therefore, the Company's corporate structure, including whether it (or its parent) is privately held or publicly traded, does not affect the analysis. That is, the ROE is not determined by reference to DENC's parent company.

Q. How did you select the companies included in your proxy group?

A. Estimating the Cost of Equity is a comparative exercise; therefore, it is necessary to develop a proxy group of companies with risk profiles that are reasonably comparable to the subject company. As each company is unique, no two companies will have identical business and financial risk profiles. In

11 NCUC Form E.S.-1 for the twelve months ended December 31, 2023, Schedule 4, page 1 and Schedule 5 (Financial Method).

selecting a proxy group, my objective is to balance the competing interests of selecting companies that are representative of the risks and prospects faced by DENC, while at the same time ensuring that there is a sufficient number of companies in the proxy group.

To develop my proxy group, I began with the 37 companies that *Value Line* classifies as Electric Utilities and applied the following screening criteria:

- Because certain of the models assume that dividends grow over time, I exclude companies that do not consistently pay quarterly cash dividends, or have cut their dividend in the last two years;

- To ensure that the growth rates used in my analyses are not biased by a single analyst, all the companies in my proxy group are consistently covered by at least two utility industry equity analysts;

- I exclude companies that do not have investment grade[12] issuer credit ratings from S&P and Moody's;

- I exclude electric utilities that are not vertically integrated (i.e., companies that primarily provide electric transmission and distribution service);

- To incorporate companies that are primarily regulated utilities, I first identify companies with at least 60.00 percent of total net operating income from regulated utility operations, on average, over the three years between 2020 and 2022. To ensure companies are primarily regulated electric utilities, I further screen these companies to exclude companies with less than 60.00 percent of regulated net

12 That is, an issuer rating of BBB- and higher from S&P and Baa3 and higher from Moody's.

operating income from regulated electric utility operations, on average, from 2020 to 2022; and

- I eliminate companies that have significant merger activity or transactions, or have had any recent financial event that could materially affect its market data or financial condition.

Q. Do you include DEI in your proxy group?

A. No. DEI is excluded from the proxy group because it would involve circular logic to include DENC's ultimate parent company in my analyses.

Q. What companies constitute your proxy group?

A. The criteria discussed above results in a proxy group of the following 18 companies:

Figure 4: Proxy Group Screening Results

Company	Ticker
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
CMS Energy Corporation	CMS
DTE Energy Corp.	DTE
Duke Energy Corporation	DUK
Edison International	EIX
Evergy, Inc.	EVRG
Entergy Corporation	ETR
IDACORP, Inc.	IDA
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
OGE Energy Corporation	OGE
Pinnacle West Capital Corporation	PNW
Portland General Electric Company	POR
The Southern Company	SO
Xcel Energy Inc.	XEL

The screening criteria results in a group of electric utilities that are comparable (but not identical) to the financial and operational characteristics of DENC. The screening criterion requiring an investment grade credit rating ensures that the proxy companies, like DENC, are in sound financial condition. Additionally, the criteria screening on the percent of net operating income from regulated electric operations ensures the proxy companies are primarily electric utilities and distinguishes between electric utilities that are subject to regulation and those with substantial unregulated operations and are exposed to higher risks. In my opinion, these screens collectively reflect key risk factors that investors consider in making investments in electric utilities.

C. Cost of Equity Models

Q. What analytical approaches do you use to estimate the Company's ROE?

A. As noted earlier, I rely on the constant growth and quarterly growth forms of the DCF model, the traditional and empirical forms of the CAPM, and the Bond Yield Plus Risk Premium approach. These models are commonly used in practice,[13] as well as in regulatory proceedings. Additionally, each model provides a different insight into investors' views of risk and return. Therefore, the use of multiple methods provides a comprehensive and robust perspective on investors' return requirements.

1. Constant Growth Discounted Cash Flow Model

Q. Please describe the Constant Growth DCF approach.

A. The Constant Growth DCF model is based on the theory that a stock's current price equals the present value of all expected future cash flows. In its simplified form, the Constant Growth DCF model shown in Equation [1] below sets the ROE equal to the expected dividend yield plus the expected long-term annual growth rate in perpetuity:

---

13 *See for example,* Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed., at 341 (1994).

$$k = \frac{D_0\ (1+g)}{\mathrm{P}} + g \qquad [1]$$

where:

k = the required ROE,

D_0 = the current annualized dividend,

P = the current stock price, and

g = the expected long-term annual growth rate.

Q. What assumptions underlie the Constant Growth DCF model?

A. The Constant Growth DCF model assumes: (1) a constant average annual growth rate for earnings and dividends; (2) dividends are paid annually, and the dividend payout ratio is stable; (3) a constant Price/Earnings multiple; and (4) a discount rate greater than the expected growth rate. The model also assumes that the current Cost of Equity remains constant in perpetuity.

Q. What market data do you use as inputs to your Constant Growth DCF analysis?

A. I calculate the Constant Growth DCF result for each of the proxy companies using the following inputs:

- The average daily closing stock prices for the 30-, 90-, and 180-trading days ended January 31, 2024, for the term P;
- The current quarterly dividend as of January 31, 2024, multiplied by 4, for the term D_0; and

- Long-term earnings per share ("EPS") growth rate projections as of January 31, 2024 reported by Zacks, Yahoo! Finance, and *Value Line* for the long-term growth rate, *g*.

Q. Why do you use three averaging periods to calculate an average stock price?

A. I do so to ensure that the model's results are not skewed by anomalous events that may affect stock prices on any given trading day. At the same time, the average period should reasonably reflect the expected capital market conditions over the long term. Using 30-, 90-, and 180-trading day averaging periods balances those concerns.

Q. How do you calculate the expected dividend yield over the coming year?

A. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Therefore, I calculate the expected dividend yield by applying one-half of the long-term growth rate to the current dividend yield. That adjustment ensures that the expected dividend yield is, on average, representative of the coming 12-month period.

Q. Why is projected EPS growth the appropriate measure of long-term growth in the Constant Growth DCF model?

A. In its constant growth form, the DCF model assumes a single expected growth rate in perpetuity, which assumes a fixed payout ratio, and the same constant growth rate in EPS, dividends per share, and book value per share. In the long run, dividend growth can only be sustained by earnings growth.

Further, academic studies have consistently shown that measures of earnings and cash flow are strongly related to returns, and that analysts' forecasts of growth are superior to other measures of growth in predicting stock prices.[14] For example, the research of Vander Weide and Carleton demonstrates that earnings growth projections have a statistically significant relationship to stock valuation levels, while dividend growth rates do not.[15] Those findings indicate that investors form their investment decisions based on expectations of growth in earnings, not dividends. Lastly, the only forward-looking growth rates that are available on a consensus basis are analysts' EPS growth rates. The fact that earnings growth projections are the only widely available estimates of growth further supports the conclusion that earnings growth is the most meaningful measure of growth among the investment community. For these reasons, earnings growth is the appropriate measure of long-term growth in the DCF model.

---

14 *See, e.g.*, Andreas C. Christofi, Petros C. Christofi, Marcus Lori and Donald M. Moliver, *Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate*, Journal of Investing (Spring 1999); Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management (Summer 1992); and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988); Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management (Spring 1986).

15 *See,* Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

Q. What are the results of your Constant Growth DCF analysis?

A. To provide a spectrum of DCF-based ROE estimates, I calculate the low, mean, and high Constant Growth DCF result for each proxy company using the low, mean, and high EPS growth estimate. The mean result combines the average of the three EPS growth rate estimates with each proxy company's expected dividend yield. The high DCF result adds the maximum EPS growth rate estimate to each proxy company's expected dividend yield. Similarly, the low DCF result adds the minimum EPS growth rate estimate for each proxy company to the expected dividend yield. I then calculate the mean and median low, mean, and high DCF results for the proxy group. In developing my ROE recommendation, I rely on the average of the mean and median proxy group Constant Growth DCF results (*see* Figure 5, below, and Exhibit JEN-2). By relying on the average of the mean and median proxy group results, the individual DCF results of each proxy company are considered while mitigating the effect of the highest and lowest estimates.

Figure 5: Constant Growth DCF Results[16]

	Low	Mean	High
30-Day Average	8.70%	9.86%	10.99%
90-Day Average	8.77%	9.94%	11.05%
180-Day Average	8.59%	9.78%	10.89%

16 Exhibit JEN-2. Average of the mean and median proxy group results.

2. Quarterly Growth DCF Model

Q. Please briefly describe the Quarterly Growth DCF model.

A. As noted earlier, the Constant Growth DCF model is based on several limiting assumptions, one of which is that dividends are paid annually. However, most dividend-paying companies, including utilities, pay dividends on a quarterly basis. Although the dividend yield adjustment discussed earlier is intended to reflect that assumption by increasing the current dividend yield by one-half of the expected growth rate, it does not fully account for the quarterly receipt and reinvestment of dividends. Consequently, the Constant Growth DCF model likely understates the Cost of Equity. The Quarterly Growth DCF model specifically incorporates the quarterly payment of dividends, and the associated quarterly compounding of those dividends as they are reinvested at the required ROE. As noted by Dr. Roger Morin:

> Clearly, given that dividends are paid quarterly and that the observed stock price reflects the quarterly nature of dividend payments, the market-required return must recognize quarterly compounding, for the investor receives dividend checks and reinvests the proceeds on a quarterly schedule ... The annual DCF model inherently understates the investors' true return because it assumes all cash flows received by investors are paid annually.[17]

17 Roger A. Morin, Ph.D., New Regulatory Finance, at 344 (2006).

Q. How is the dividend yield component of the Quarterly Growth DCF model calculated?

A. To reflect the timing and compounding of quarterly dividends more accurately, the model replaces the "D" component of the Constant Growth DCF equation with the following equation:

$$D = d_1(1+k)^{0.75} + d_2(1+k)^{0.50} + d_3(1+k)^{0.25} + d_4(1+k)^{0} \quad [2]$$

where:

d_1, d_2, d_3, d_4 = expected quarterly dividends over the coming year; and

k = the required Return on Equity.[18]

To calculate the expected dividends over the coming year for the proxy companies (*i.e.*, d_1, d_2, d_3, and d_4), I obtained the last four paid quarterly dividends for each company and multiplied them by one plus the earnings growth rate (*i.e.*, $1 + g$). To provide a spectrum of quarterly growth DCF-based ROE estimates, I calculate the low, mean, and high quarterly growth DCF result for each proxy company using the low, mean and high EPS growth estimate. For the *P* component of the dividend yield, I used the same average stock prices applied in the Constant Growth DCF analysis for each proxy company.

Q. What are the results of your Quarterly Growth DCF analysis?

A. My Quarterly Growth DCF results are summarized in Figure 6, below (*see also* Exhibit JEN-3). As with my Constant Growth DCF analysis, I rely on the average of the mean and median proxy group results.

18 Because the required ROE (k) is a variable in the dividend yield calculation, the Quarterly Growth DCF model is solved iteratively.

Figure 6: Quarterly Growth DCF Results[19]

	Low	Mean	High
30-Day Average	8.85%	10.05%	11.21%
90-Day Average	8.92%	10.13%	11.28%
180-Day Average	8.74%	9.95%	11.11%

3. Capital Asset Pricing Model and Empirical Capital Asset Pricing Model

Q. Please describe the general form of the CAPM.

A. The CAPM is a risk premium method that estimates the Cost of Equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security. As shown in Equation [3], the CAPM is defined by four components, each of which theoretically is a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \qquad [3]$$

where:

K_e = the required market ROE for a security;

β = the Beta coefficient of that security;

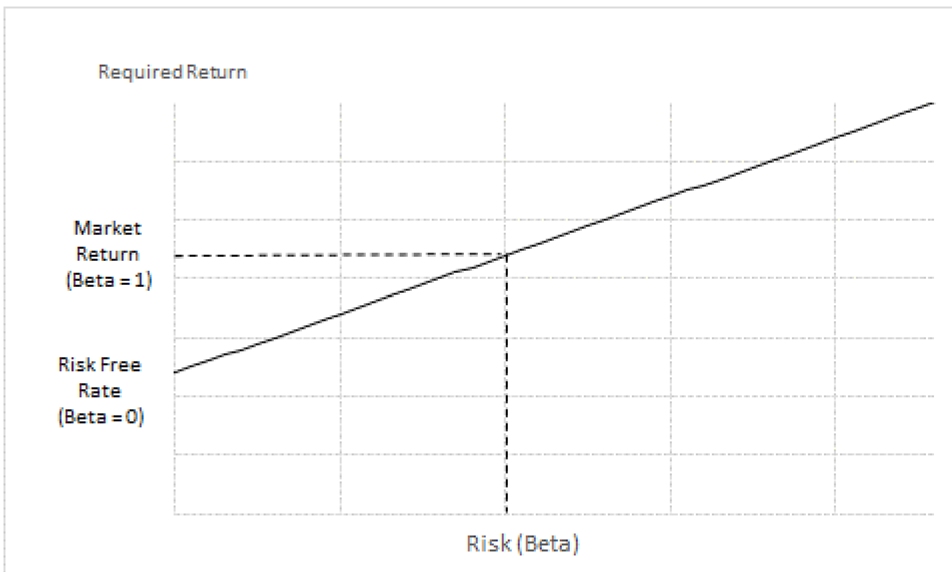
r_f = the risk-free rate of return; and

r_m = the required return on the market.

19 Exhibit JEN-3. Average of the mean and median proxy group results.

Equation [3] describes the Security Market Line ("SML"), or the CAPM risk-return relationship, depicted in Figure 7 below. The intercept is the risk-free rate (r_f) that has a Beta coefficient of zero, and the slope is the expected market risk premium ($r_m - r_f$). As shown in Figure 7, the SML is upward sloping, illustrating the principle that investments of higher risk require a higher return. By definition, r_m, the return on the market, has a Beta coefficient of 1.00.

Figure 7: Security Market Line



The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic risk. Systematic (or non-diversifiable) risk is measured by the Beta coefficient, which is defined as:

$$\beta_j = \frac{\sigma_j}{\sigma_m} \times \rho_{j,m} \quad [4]$$

where σ_j is the standard deviation of returns for company "*j*," σ_m is the standard deviation of returns for the broad market (as measured, for example, by the S&P 500 Index), and $\rho_{j,m}$ is the correlation of returns in between company *j* and the broad market. The Beta coefficient, therefore, represents both relative volatility (*i.e.*, the standard deviation) of returns, and the correlation in returns between the subject company and the overall market. Intuitively, higher Beta coefficients indicate that the subject company's returns have been relatively volatile compared to the overall market and have moved in the same direction as the overall market.

Q. What risk-free rates do you apply in your CAPM analysis?

A. I apply two estimates of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds (4.19 percent)[20] and (2) a projected 30-year Treasury yield (4.14 percent).[21]

Q. Why do you rely on the 30-year Treasury yield as the risk-free rate in your CAPM analysis?

A. In determining the security most relevant to the application of the CAPM, the term (or maturity) should approximate the life of the underlying investment.

20 Source: Bloomberg Professional Service as of January 31, 2024.

21 The average of: (1) the average projected 30-year Treasury yield for the six quarters ended Q2 2025 and (2) the average long-term projected 30-year Treasury yield for the years 2025-2029 and 2030-2034 reported by *Blue Chip Financial Forecasts*. *See*, *Blue Chip Financial Forecasts*, Vol. 43, No. 2, February 1, 2024, at 2, and Vol. 42, No. 12, December 1, 2023, at 14.

Electric utilities are typically long-duration investments; therefore, the 30-year Treasury yield is most suitable for the risk-free rate applied in the CAPM.

Q. What Beta coefficients do you use in your CAPM analyses?

A. As shown in Exhibit JEN-5, my CAPM analyses rely on the average Beta coefficients from *Value Line* and Bloomberg for each proxy company as of January 31, 2024. Beta coefficients from both services are calculated using weekly returns over a five-year period, adjusted to reflect the tendency of Beta coefficients to regress toward the market mean of 1.00.

Q. What estimates of the expected market return do you use to calculate the market risk premium?

A. I considered two estimates of the expected market return. The first estimate calculates the market capitalization-weighted ROE of the S&P 500 Index by applying the Constant Growth DCF model to the S&P 500 Index. The second estimate is the long-run historical arithmetic average market return of 12.02 percent reported by Kroll (formerly Duff & Phelps) for the years 1926 to 2022.[22]

Q. Please explain further your forward-looking DCF approach to estimating the market return.

A. Using the Constant Growth DCF model described earlier, I developed two estimates of the expected market return by applying dividend yields from

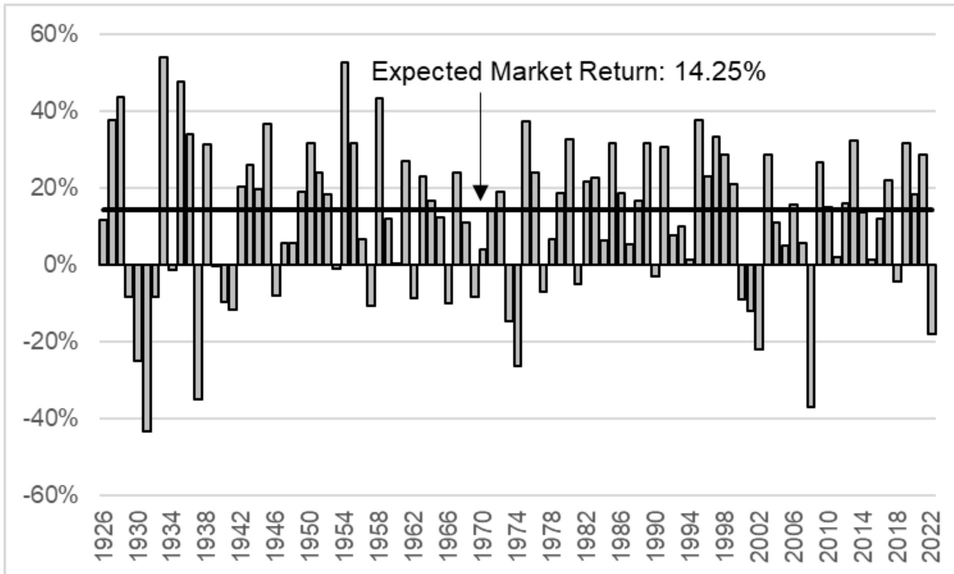
22 Kroll, 2023 SBBI Yearbook, Appendix A-1.

Bloomberg and projected earnings growth rates from Bloomberg and *Value Line*. I calculated a market capitalization-weighted dividend yield and projected earnings growth rate for the S&P 500 Index and applied those estimates to the Constant Growth DCF formula, using the same half-growth rate assumption described earlier. The expected market return from Bloomberg and *Value Line* are 15.43 percent and 14.25 percent, respectively (*see* Exhibit JEN-4). To be conservative, I rely on *Value Line's* expected market return estimate of 14.25 percent in my CAPM analyses.

Q. Is a market return estimate of 14.25 percent reasonable and consistent with actual observed market returns?

A. Yes, it is. As shown in Figure 8 below, a market return of 14.25 percent or higher occurred in 49 of the last 97 years (*i.e.*, 51 percent of the time). Since 2009, the annual market return has averaged 14.07 percent, and equaled or exceeded 14.25 percent in eight of the last 14 years, and 10 of the last 20 years. In other words, an annual market return of 14.25 percent, or higher, has occurred frequently.

Figure 8: Annual Market Return (1926 – 2022)[23]



Q. Why do you also consider the long-term arithmetic average historical return on the market of 12.02 percent as an alternate estimate of the expected market return?

A. My objective is to develop a reasonable estimate of the expected market return over the long term to calculate an expected market risk premium. Because the Cost of Equity is forward looking, any estimate – whether based on historical or projected data – assumes the estimate reflects investors' expectations into the future. From that perspective, applying the long-run historical arithmetic average market return as an alternate estimate of the expected market return is prospective in nature. The 14.25 percent expected market return is consistent with historically observed market returns (as shown in Figure 8 above) yet is above the long-term arithmetic average market return. Therefore, it may be

23 Source: Kroll, 2023 SBBI Yearbook, Appendix A-1, A-7.

reasonable to expect that, over the long term, the market return will revert to its long-run historical arithmetic average.

Q. With the risk-free rates and expected market return estimates described above, how do you calculate the market risk premium?

A. I apply two estimates of the risk-free rate and two estimates of the expected market return. Combined, those variables produce four estimates of the market risk premium, ranging from 7.83 percent to 10.10 percent as shown below in Figure 9.

Figure 9: Market Risk Premium Estimates

	Current Risk-Free Rate (4.19%)	**Projected Risk-Free Rate (4.14%)**
DCF-based Expected Market Return (14.25%)	10.06%	10.10%
Long-Term Historical Average Market Return (12.02%)	7.83%	7.87%

Q. What are the results of your CAPM analysis?

A. As shown in Exhibit JEN-5, the CAPM results range from 11.25 percent to 13.27 percent (*see* Figure 10 below).

Figure 10: Summary of CAPM Results[24]

	Current 30-Year Treasury Yield (4.19%)	Projected 30-Year Treasury Yield (4.14%)
Long-Term Historical Average Market Return	11.26%	11.25%
DCF-Based Expected Market Return	13.27%	13.27%

Q. Do you consider another form of the CAPM?

A. Yes, I also consider the Empirical CAPM ("ECAPM") approach, which calculates the product of the adjusted Beta coefficient and the market risk premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the market risk premium, without any effect from the Beta coefficient.[25] The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as shown in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \quad [5]$$

Q. What is the benefit of the ECAPM approach?

A. The ECAPM corrects for the tendency of the CAPM to underestimate the Cost of Equity for companies, such as regulated utilities, with low Beta coefficients, and to overstate the Cost of Equity for companies with high Beta coefficients. As discussed below, the ECAPM recognizes academic research that indicates

24 Exhibit JEN-5, average of the mean and median CAPM results.

25 *See, e.g.*, Roger A. Morin, Ph.D., New Regulatory Finance, at 189-190 (2006).

the risk-return relationship is flatter than that estimated by the CAPM, and that the CAPM under-estimates the Alpha (α), or the constant return term.[26]

Numerous tests of the CAPM have measured the extent to which security returns and Beta coefficients are related as predicted by the CAPM. The ECAPM method reflects the finding that the actual SML described by the CAPM formula is not as steeply sloped as the predicted SML.[27] Fama and French found that the actual returns on the low Beta coefficient portfolios were higher than the CAPM-predicted returns, and vice versa for the high Beta coefficient portfolios.[28] Similarly, Morin states:

> With few exceptions, the empirical studies agree that . . . low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. . . .
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K = R_F + x\,(R_M - R_F) + (1\text{-}x)\beta(R_M - R_F)$$
>
> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = R_F + 0.25(R_M - R_F) + 0.75\ \beta(R_M - R_F)$$ [29]

26 Roger A. Morin, Ph.D., New Regulatory Finance, at 191 (2006).

27 Roger A. Morin, Ph.D., New Regulatory Finance, at 175 (2006). The Security Market Line plots the CAPM estimate on the Y-axis, and Beta coefficients on the X-axis.

28 Eugene F. Fama & Kenneth R. French, *The Capital Asset Pricing Model: Theory and Evidence*, Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004, at 33.

29 Roger A. Morin, Ph.D., New Regulatory Finance, at 175, 190 (2006).

Q. Does the use of adjusted Beta coefficients in the ECAPM address the empirical issues with the CAPM?

A. No, it does not. Beta coefficients are adjusted because of their general regression tendency to converge toward 1.00 over time, i.e., over successive calculations. As also noted earlier, numerous studies have determined that at any given point in time, the SML described by the CAPM formula is not as steeply sloped as the predicted SML. To that point, Morin explains:

> Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. [30]

---

30 Roger A. Morin, Ph.D., New Regulatory Finance, at 191 (2006).

Therefore, as the Commission acknowledged in Docket No. E-2, Sub 1300,[31] it is appropriate to rely on adjusted Beta coefficients in both the CAPM and ECAPM.

Q. Are you aware of academic studies that support the use of the ECAPM for utilities?

Yes, I am. In a 2011 study by Stéphane Chrétien and Frank Coggins, the authors studied the CAPM's ability to estimate the risk premium for the utility industry in particular subgroups of utilities.[32] The study considered the traditional CAPM approach, the Fama-French three-factor model, and a model similar to the ECAPM. In the study, the ECAPM relied on adjusted Beta coefficients similar to *Value Line*'s approach. As Chrétien and Coggins found, the ECAPM significantly outperformed the traditional CAPM model at predicting the observed risk premium for the various utility subgroups.

Q. Has the Commission previously accepted the ECAPM?

A. Yes. In the Commission's Order in the Company's last rate case, the Commission found the ECAPM, to be "credible, probative, and entitled to

---

31 North Carolina Utilities Commission, Docket No. E-2, Sub 1300, *In the Matter of Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation,* Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice, at 162-163 (August 18, 2023).

32 Stéphane Chrétien and Frank Coggins, *Cost of Equity for Energy Utilities: Beyond The CAPM*, Energy Studies Review, Vol. 18, No. 2 (2011).

substantial weight."[33] More recently, the Commission accepted the ECAPM in Duke Energy Progress' most recent rate case, Docket No. E-2, Sub 1300.[34]

Q. What are the results of your ECAPM analyses?

A. I apply the same market return, Beta coefficients, and risk-free rates described earlier to Equation [5] above. The results of my ECAPM analysis are summarized in Figure 11 below.

Figure 11: Summary of ECAPM Results[35]

	Current 30-Year Treasury Yield (4.19%)	Projected 30-Year Treasury Yield (4.14%)
Long-Term Historical Average Market Return	11.45%	11.44%
DCF-Based Expected Market Return	13.52%	13.51%

4. Bond Yield Plus Risk Premium Approach

Q. Please describe the Bond Yield Plus Risk Premium approach.

A. The Bond Yield Plus Risk Premium approach is based on the basic financial principle of risk and return, which states that equity investors require a premium over the return required as a bondholder to account for the incremental residual

33 North Carolina Utilities Commission, Docket No. E-22, Sub 562, *In the Matter of Application of Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina,* Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, at 41 (February 24, 2020).

34 North Carolina Utilities Commission, Docket No. E-2, Sub 1300, *In the Matter of Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation,* Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice, at 163 (August 18, 2023).

35 Exhibit JEN-5, average of the mean and median ECAPM results.

risk associated with equity ownership. Risk premium approaches estimate the Cost of Equity as the sum of the equity risk premium and the yield on a particular class of bonds.

Q. Please explain how you perform your Bond Yield Plus Risk Premium analysis.

A. I first define the equity risk premium as the difference between the authorized ROE and the then-prevailing 30-year Treasury bond yield, using the authorized ROE for 1,780 electric utility rate proceedings between January 1, 1980, and January 31, 2024. To reflect the prevailing bond yields during the pendency of each proceeding, I calculate the average 30-year Treasury yield over the average lag period between the filing of the rate case and the date of the final order (approximately 200 days).

Because the data covers several economic cycles over more than four decades, the analysis incorporates changes in the equity risk premium over time. Prior research has shown that the equity risk premium is inversely related to the level of bond yields.[36]

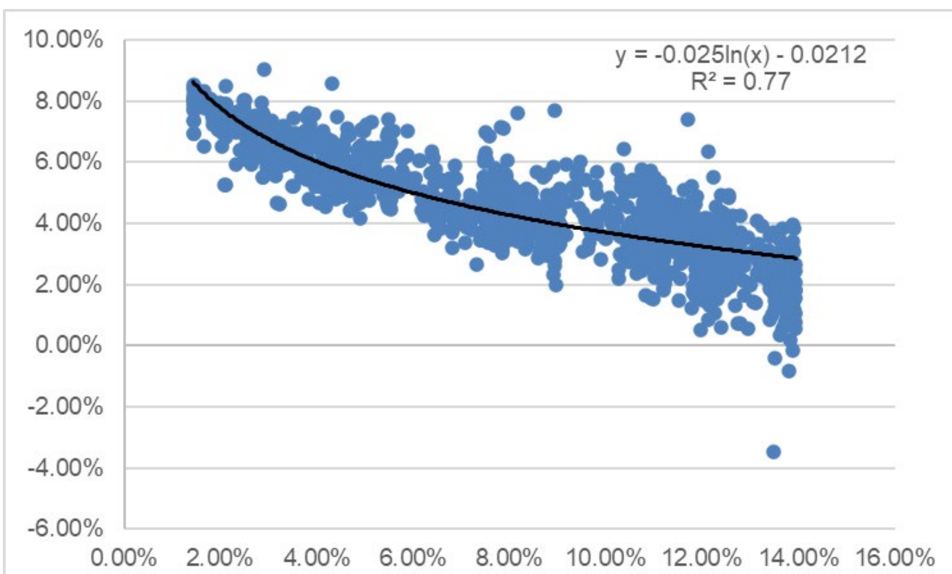
36 *See*, *e.g.,* Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, at 63-70 (Summer 1992); Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, at 33-45 (Spring 1985); and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, at 89-95 (Autumn 1995).

Q. How do you analyze the relationship between bond yields and the equity risk premium?

A. I estimate the relationship between bond yields and the equity risk premium by applying a regression analysis, in which the equity risk premium described above is the dependent variable, and the 30-year Treasury yield is the independent variable. To account for the variability in bond yields and authorized ROEs over several decades, I use the semi-log regression, in which the equity risk premium is expressed as a function of the natural log of the 30-year Treasury yield:

$$\text{RP} = \alpha + \beta \left(LN\left(T_{30}\right) \right) \quad [6]$$

Figure 12: Equity Risk Premium[37]



37 Exhibit JEN-6.

As Figure 12 above illustrates, the equity risk premium increases as interest rates fall. The finding that the equity risk premium and interest rates are inversely related is supported by published research. For example, Dr. Roger Morin cites several studies and concludes that, "beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when interest rates rose."[38] Applying the regression coefficients in Figure 12 produces an ROE estimates of 10.08 percent to 10.10 percent (*see* Figure 13 and Exhibit JEN-6).

Figure 13: Summary of Bond Yield Plus Risk Premium Results[39]

	30-Year Treasury Bond	Risk Premium	Return on Equity
Current 30-Year Treasury	4.19%	5.91%	10.10%
Projected 30-Year Treasury	4.14%	5.94%	10.08%

IV. BUSINESS RISKS AND OTHER CONSIDERATIONS

Q. Did you consider additional factors when developing your ROE recommendation for DENC?

A. Yes, I did. As explained below, I considered DENC's planned capital expenditures and capital access requirements, as well as the regulatory environment in which it operates.

38 Roger A: Morin, Ph.D., New Regulatory Finance, at 128 (2006).

39 Exhibit JEN-6.

A. Capital Expenditures, Regulatory Environment, and Capital Access

Q. Do you have any preliminary thoughts on the importance of access to capital for electric utilities such as DENC?

A. Yes, I do. As a capital-intensive enterprise, the allowed ROE should enable DENC to finance capital expenditures and working capital requirements at reasonable rates and to maintain its financial integrity in a variety of economic and capital market conditions. As discussed throughout my Direct Testimony, a return that is adequate to attract capital at reasonable terms enables the utility to provide safe, reliable service while maintaining its financial soundness to the benefit of customers.

Electric utilities are one of the most capital-intensive market sectors. On average, electric utilities generate approximately 70 percent less revenue per dollar of assets than the non-utility U.S. companies covered by *Value Line*.[40] To fund the significant capital expenditures needed to maintain, and modernize existing infrastructure, electric utilities require sufficient internally generated cash flow and ongoing access to investor supplied capital. Because electric utilities are often cash flow negative (*i.e.*, cash spent on plant is often more than cash flow received from operations), it is critical that regulation enable timely cost recovery and provide predictable, adequate, and achievable allowed returns that support the financial integrity of the utility.

40 Source: *Value Line,* accessed January 26, 2024.

Q. Please briefly summarize the Company's capital investment requirements.

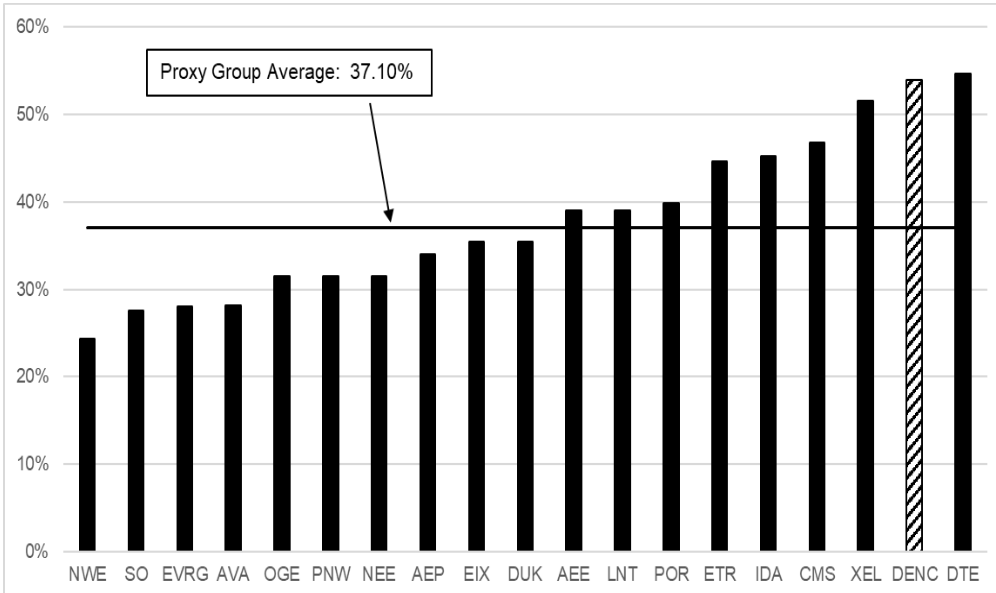
A. The Company is planning approximately $35.5 billion in capital expenditures across the two states it operates in during the 2025 to 2029 timeframe to fund investments in (1) electric transmission and distribution infrastructure; (2) solar and offshore wind generation, as well as battery storage; (3) its nuclear operations and subsequent license renewal; (4) grid transformation investment; and (5) other maintenance, environmental, and generation capital.[41]

Over the next three years, the Company's planned capital expenditures between would reflect a 54 percent increase in the Company's Net Property Plant & Equipment ("PP&E") as of December 31, 2023.[42] As shown in Figure 14 below (*see also* Exhibit JEN-7), the Company's planned capital investment over the next three years relative to 2023 Net PP&E is the second highest in the proxy group.

41 Dominion Energy Inc. Investor Presentation, "Business Review Investor Meeting," at slide 39, 51 (March 1, 2024).

43 *See* Exhibit JEN-7. Sources: S&P Capital IQ; Dominion Energy Inc. 2023 10-K, at p. 81 (2024); and Dominion Energy Inc., Investor Presentation, March 1, 2024, at slide 39 (2025-2026).

Figure 14: Proxy Group 2024-2026 Capital Expenditures to 2023 Net PP&E[43]



Because the Company must make substantial investments in its utility operations regardless of the economic and financial market environment at the time, it will require ongoing efficient access to external capital.

Q. How do the Company's capital expenditure requirements affect its risk profile?

A. As with any utility facing substantial capital expenditure requirements, the Company's risk profile is affected in two significant and related ways: (1) the heightened level of investment increases the risk of under recovery or delayed recovery of the invested capital; and (2) an inadequate return would put

43 *See* Exhibit JEN-7. Sources: S&P Capital IQ; Dominion Energy Inc. 2023 10-K, at p. 81 (2024); and Dominion Energy Inc., Investor Presentation, March 1, 2024, at slide 39 (2025-2026).

downward pressure on key credit metrics due to both the reduction in cash flow and an increase in debt to fund its expenditures.

Q. Do credit rating agencies recognize the risks associated with elevated levels of capital expenditures?

A. Yes. From a credit perspective, the additional pressure on cash flows associated with higher levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[44]

To the extent that the regulatory environment does not enable timely and sufficient cost recovery of its full cost of doing business, including capital costs, the Company will face increased pressure on its credit metrics thus raising the

---

44 S&P Global Ratings, *Assessing U.S. Investor-Owned Utility Regulatory Environments*, at 7 (August 10, 2016).

cost of both debt and equity. Maintaining access to capital markets on favorable terms is especially important for utilities and their customers during periods of significant capital investment.

Q. Have the rating agencies commented on the Company's planned capital expenditures?

A. Yes. Moody's regards the Company's "elevated capital investments to support load growth and transition to clean power" as a "credit challenge."[45] Fitch discussed the Company's significant investment related to the Coastal Virginia Offshore Wind project. Although Fitch acknowledged the capital cost recovery mechanism approved by the Virginia State Corporation Commission ("SCC") as "favorable," it noted that it remains "concerned about the impact if significant delays or cost escalation were incurred."[46] Fitch further noted that the Company has diminished headroom in its credit metric profile and is approaching its downgrade threshold, despite timely cost recovery mechanisms and favorable legislation in Virginia.[47] The rating agencies' comments demonstrate that regulatory support is critical for the Company to successfully execute its significant capital investment plan while maintaining its financial integrity to the benefit of customers. Importantly, while constructive regulatory mechanisms may mitigate some risk, they do not eliminate risk.

45 Moody's Investors Service, *Credit Opinion: Virginia Electric and Power Company*, at 2 (May 4, 2023).

46 Fitch Ratings, *Virginia Electric and Power Company*, at 1 (December 20, 2023).

47 Fitch Ratings, *Virginia Electric and Power Company*, at 2 (December 20, 2023).

Q. How does the regulatory environment influence utilities' efficient access to capital?

A. The regulatory environment is one of the most important factors investors consider when assessing a utility's risk, as it is a significant driver of earnings and cash flow that are of utmost importance to investors.[48] Investors and rating agencies understand that a constructive regulatory environment is critical to utilities' credit and financial integrity, especially during stressed market conditions. In fact, 50 percent of the factors that weigh in Moody's ratings determinations relate to the nature of regulation.[49] Predictability and consistency of regulatory actions are among the factors considered by Moody's in assessing the regulatory framework:

> As the revenues set by the regulator are a primary component of a utility's cash flow, the utility's ability to obtain predictable and supportive treatment within its regulatory framework is one of the most significant factors in assessing a utility's credit quality.
>
> ***
>
> In situations where the regulatory framework is less supportive, or is more contentious, a utility's credit quality can deteriorate rapidly.[50]

---

48 Moody's Investors Service, *Rating Methodology, Regulated Electric and Gas Utilities*, at 4 (June 23, 2017).

49 Moody's Investors Service, *Rating Methodology, Regulated Electric and Gas Utilities*, at 4 (June 23, 2017).

50 Moody's Investors Service, *Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities*, at 2 (June 18, 2010).

Similarly, S&P observes that the regulatory environment in the jurisdictions where a utility operates is a "significant aspect of regulatory risk that influences credit quality".[51] S&P explains:

> "[w]hen we evaluate U.S utility regulatory environments, we consider financial stability to be of substantial importance. Cash takes precedence in credit analysis. A regulatory jurisdiction that recognizes the significance of cash flow in its decision-making is one that will appeal to creditors."[52]

Consequently, a utility that operates in a less predictable and more challenging regulatory environment is likely to be viewed as a riskier investment, and may result in lower credit ratings, constrained access to capital (particularly in adverse market environments), and higher costs of both debt and equity, all else being equal. From that perspective, customers benefit from a constructive regulatory environment.

Q. Have you considered the Company's regulatory risk relative to the proxy group?

A. Yes, I have. The regulatory environment significantly affects both the access to and the cost of capital. Regulatory decisions regarding the authorized ROE and capital structure directly affect the subject utility's internal cash flow generation, and therefore the financial metrics reviewed by ratings agencies in their ratings assessments. Because credit ratings are intended to reflect the

---

51 S&P Global Ratings, *RatingsDirect, Assessing U.S. Investor-Owned Utility Regulatory Environments*, at 2 (August 10, 2016).

52 S&P Global Ratings, *RatingsDirect, Assessing U.S. Investor-Owned Utility Regulatory Environments*, at 6 (August 10, 2016).

ability to meet financial obligations as they come due, the ability to generate the cash flows required to meet those obligations (and to provide a cushion for unexpected events) is of critical importance to both debt and equity investors.

To assess the regulatory environment of the proxy companies and DENC, I reviewed the key cost recovery mechanisms and ratemaking frameworks for each of the electric operating companies within the proxy group in the jurisdictions in which they operate, including cost recovery and volumetric risk mitigation mechanisms, test year, and rate base methodology.

As shown in Exhibit JEN-8, like DENC, all the proxy group operating companies have a fuel and/or purchased power cost recovery mechanism and 86 percent have a mechanism to recover energy efficiency program costs. While the Commission has not authorized DENC a mechanism to recover capital costs outside of base rates, I recognize that the Virginia SCC has authorized such capital cost recovery mechanisms for the Company. Further, while the Commission uses an historical test year and historical year end rate base, I understand that the Virginia SCC allows adjustments to rate base and cost-of-service components to reflect future costs that can be reasonably expected to occur in the future rate year, effectively utilizing a forecast test year and projected rate base.[53] As shown in Exhibit JEN-8, 51 percent of the proxy group operating companies are also allowed to use a forecasted test year.

53 Regulatory Research Associates, Commission Profiles, Virginia State Corporation Commission, accessed February 23, 2024.

Lastly, while DENC's North Carolina can recover lost revenue associated with its energy efficiency programs, I understand that in Virginia, the Company is able to apply a true-up mechanism to mitigate volumetric risk through a rider, rendering the Company comparable to the proxy group in which 64 percent have a mechanism that mitigates volumetric risk.

On balance, from an investor perspective, the regulatory mechanisms available to the Company do not offer any level of risk mitigation that is meaningfully different from the proxy companies. Furthermore, these regulatory mechanisms are only as effective as their implementation, including a compensatory return. Lastly, I recognize that Regulatory Research Associates ("RRA") ranks the Commission as "Above Average/3"[54] and views North Carolina's regulatory climate as "relatively constructive from an investor viewpoint."[55] It is important that this perception of the constructiveness of the regulatory environment in North Carolina be maintained.

Q. Do the Company's regulatory mechanisms reduce its risk?

A. No, they do not. The Company employs cost recovery mechanisms similar to those used by the proxy group; as such, its risk relative to the proxy group is

54 RRA maintains three principal rating categories for regulatory climates: Above Average, Average, and Below Average. Within the principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger rating; 2, a mid-range rating; and, 3, a weaker rating. The evaluations are assigned from an investor perspective and indicate the relative regulatory risk associated with the ownership of securities issued by the jurisdiction's utilities. RRA endeavors to maintain an approximately equal number of ratings above the average and below the average..

55 Regulatory Research Associates, Commission Profiles, North Carolina Utilities Commission, accessed February 23, 2024.

not reduced as a result of its rate structures. Further, because the proxy companies all have similar mechanisms, any effects on the Cost of Equity associated with the rate mechanisms are captured in the analytical model results.

It is important to remember that risk assessment is a comparative exercise. Rate adjustment mechanisms are common in the industry and the financial community is fully aware of their prevalence. In fact, rate adjustment mechanisms have become more common in the industry, not less. As noted earlier, the proxy companies all have similar mechanisms available to them. While the specific details of the mechanics of the rate adjustment mechanisms may differ from utility to utility and jurisdiction to jurisdiction, their objective is the same: To improve the timeliness of cost recovery and mitigate (but not necessarily eliminate) earnings erosion associated with regulatory lag. Because the proxy companies all have mechanisms that improve the timeliness of cost recovery, the Company's regulatory mechanisms simply render it more comparable to its peers.

Q. What are your conclusions regarding the Company's capital expenditure requirements, its need to maintain access to capital, and the regulatory environment on its risk profile?

A. The Company's ratio of capital expenditure requirements to net PP&E is higher than the ratio for any of the proxy group companies and approximately 1.7 times the proxy group median, which places pressure on the Company's credit metrics. Given the magnitude of its capital expenditure requirements, the Company requires ready access to cash flows and external capital to meet its obligation to provide safe and reliable service and provide customers with the benefits of the clean energy transition. Therefore, regulatory support is critical to the Company's ability to finance and earn a reasonable return on its planned utility investments. Additionally, the Company's regulatory mechanisms support its ability to recover costs in a timely manner and render it comparable in risk to its peers. Therefore, there is no reduction in the Company's risk, or its ROE, on account of its regulatory mechanisms.

The regulatory environment is one of the most important issues considered by both debt and equity investors in assessing the risks and prospects of utility companies. The return authorized by the Commission in this proceeding will send an important signal to the financial community regarding the constructiveness of the regulatory environment in North Carolina. From the perspective of investors, the authorized return should enable the Company to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its system, and maintain sufficient levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also from efficient access to external capital. Because utilities are capital intensive enterprises, it is essential that the ROE authorized in this proceeding enable DENC to continue to invest the capital necessary to meet its obligation to serve in a variety of market environments, as well as maintain confidence in North Carolina's regulatory environment among credit rating agencies and investors.

V. ECONOMIC CONDITIONS IN NORTH CAROLINA

Q. Did you consider the economic conditions in North Carolina in arriving at your ROE recommendation?

A. Yes, I did. I understand that the Commission must balance the interests of investors and customers in setting the ROE. As the Commission has stated, it "…is and must always be mindful of the North Carolina Supreme Court's command that the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions."[56] In that regard, the return should be neither excessive nor confiscatory; it should be the minimum amount needed to meet the *Hope* and *Bluefield* Comparable Risk, Capital Attraction, and Financial Integrity standards.

The Commission also has found the role of cost of capital experts is to determine the investor-required return, not to estimate increments or decrements of return in connection with consumers' economic environment:

> … adjusting investors' required costs based on factors upon which investors do not base their willingness to invest is an unsupportable theory or concept. The proper way to take into account customer ability to pay is in the Commission's exercise of fixing rates as low as reasonably possible without violating constitutional proscriptions against confiscation of property.

---

56 State of North Carolina Utilities Commission, Docket No. E-7, Sub 1026, *Order Granting General Rate Increase*, Sept. 24, 2013 at 25; *see also,* North Carolina Utilities Commission, Docket No. E-7, Sub 989, *Order on Remand*, October 23, 2013 at 31 ("the Commission in every case seeks to comply with the N.C. Supreme Court mandate that the Commission establish rates as low as reasonably possible within Constitutional limits.").

> This is in accord with the "end result" test of <u>Hope</u>. This the Commission has done.[57]

The North Carolina Supreme Court agreed, and upheld the Commission's Order on Remand.[58] The North Carolina Supreme Court has also made clear that the Commission "must make findings of fact regarding the impact of changing economic conditions on customers when determining the proper ROE for a public utility."[59] In *Cooper II*, the North Carolina Supreme Court directed the Commission on remand to "make additional findings of fact concerning the impact of changing economic conditions on consumers",[60] which the Commission made in its Order on Remand.[61] In light of the *Cooper II* decision and the North Carolina Supreme Court precedent that preceded it,[62] I appreciate the Commission's need to consider economic conditions in the State. With those directives in mind, I have undertaken several analyses to provide such a review.

---

57 State of North Carolina Utilities Commission, Docket No. E-7, Sub 989, *Order on Remand*, October 23, 2013, at 34 – 35; *see also,* State of North Carolina Utilities Commission, Docket No. E-22, Sub 479, *Order on Remand*, July 23, 2015 at 26 (stating that the Commission is not required to "isolate and quantify the effect of changing economic conditions on consumers in order to determine the appropriate rate of return on equity").

58 *See, State of North Carolina ex rel. Utilities Commission v. Cooper*, 367 N.C. 644, 766 S.E.2d 827 (Dec. 2014).

59 *State of North Carolina ex rel. Utilities Commission v. Cooper*, 366 N.C. 484, 739 S.E.2d 548 (April 2013) ("*Cooper I*").

60 *State of North Carolina ex rel. Utilities Commission v. Cooper*, 367 N.C. 430, 758 S.E.2d 635, 643 (June 2014) ("*Cooper II*").

61 *See,* State of North Carolina Utilities Commission, Docket No. E-22, Sub 479, *Order on Remand*, at 4-10.

62 *See*, *Cooper I*.

Q. Please summarize your analyses and conclusions.

A. In its Order on Remand in Docket No. E-22, Sub 479, the Commission observed that economic conditions in North Carolina were highly correlated with national conditions, such that they were reflected in the analyses used to determine the Cost of Equity.[63] As discussed below, those relationships still hold:

- Although economic conditions in North Carolina declined significantly in the second quarter of 2020 as a result of the COVID-19 pandemic, they have improved considerably since. Notably, economic conditions in North Carolina continue to be strongly correlated to the U.S. economy;
- Unemployment at both the state and county level remains highly correlated with national rates of unemployment;
- Real Gross Domestic Product ("GDP") in North Carolina has outperformed the U.S. economy in nine of the last 15 quarters and remains highly correlated with U.S. real GDP growth; and
- Median household income in North Carolina has grown at a rate consistent with the rest of the U.S. and remains strongly correlated with national levels. Between 2012 and 2022, per capita disposable personal income in North Carolina has grown faster than the U.S. overall, and disposable personal income in North Carolina was the 16th fastest growing of all states and the District of Columbia over the last ten years; and

63 *See,* State of North Carolina Utilities Commission, Docket No. E-22, Sub 479, *Order on Remand*, July 23, 2015, at 39.

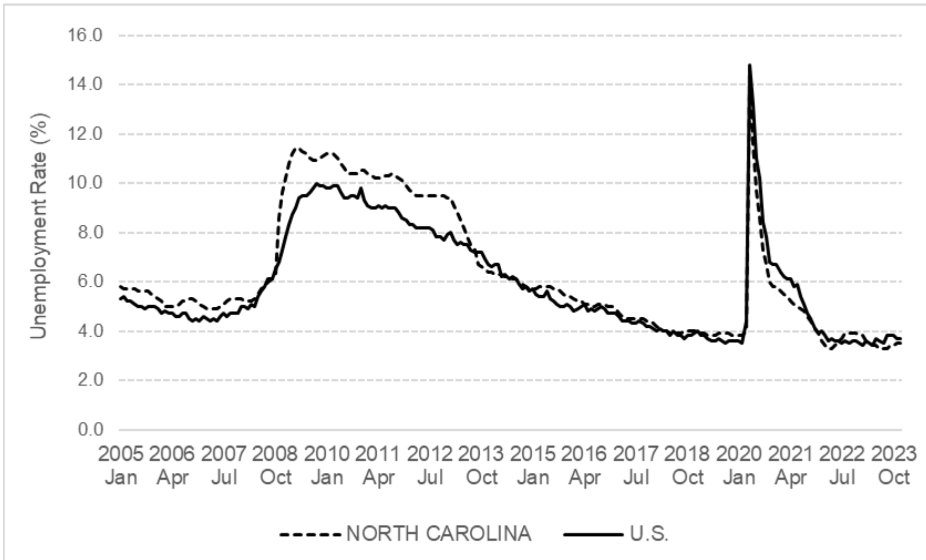
- North Carolina's retail electricity prices are below the national average, and rank as the 9th lowest in the U.S. as of 2022, an improvement from 2001 when North Carolina had the 27th cheapest retail electricity prices.

On balance, the correlations between statewide measures of economic conditions noted by the Commission in Docket No. E-22, Sub 479 remain in place and, as such, they continue to be reflected in the models used to estimate the Cost of Equity.

Q. Please now describe the specific measures of economic conditions that you reviewed.

A. Turning first to the seasonally adjusted unemployment rate, prior to April 2020, unemployment had fallen substantially in North Carolina and the U.S. since the 2008/2009 financial crisis. Although the unemployment rate in North Carolina exceeded the national rate during and after the 2008/2009 financial crisis, by the latter portion of 2013, the two were largely consistent. As the COVID-19 pandemic hit the U.S., unemployment in North Carolina and across the U.S. spiked in April 2020 as many communities closed non-essential businesses to contain the spread of the COVID-19 virus. North Carolina's unemployment rate has fared better than the overall U.S. unemployment rate by about 0.4 percent on average since April 2020, even as both have fallen since their peaks in early 2020 (*see* Figure 15, below).

Figure 15: Unemployment Rate (Seasonally Adjusted)[64]



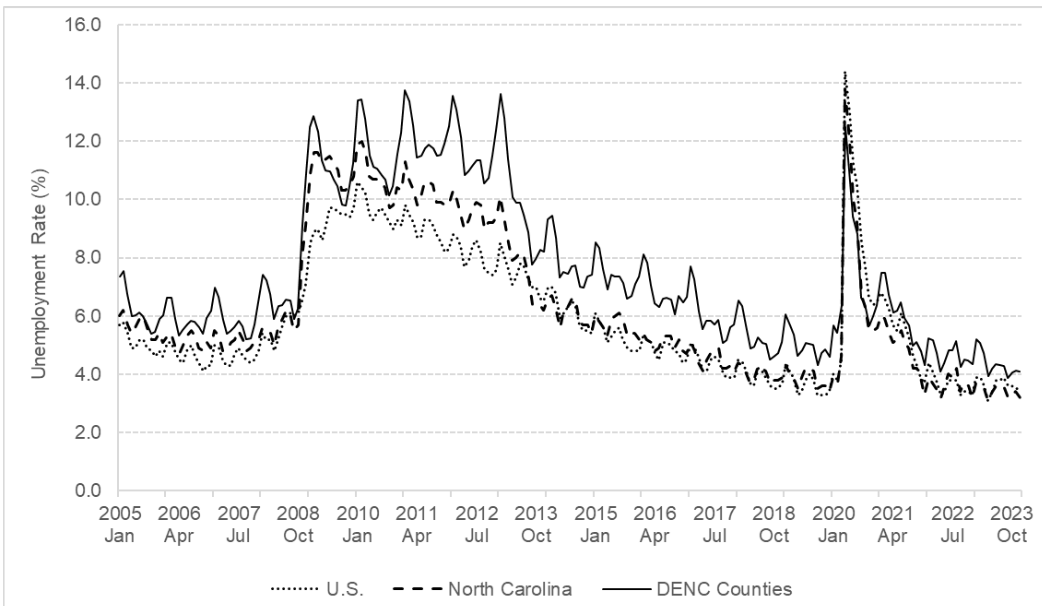
Between 2005 and 2023, the correlation between North Carolina's unemployment rate and the national rate was 96.56 percent, indicating the two are highly correlated.

Second, I reviewed seasonally unadjusted unemployment rates in the 19 counties served by DENC. As with the seasonally adjusted unemployment rates described above, the seasonally unadjusted unemployment rate in those counties spiked in April 2020 to 12.49 percent on average, but by December 2023 it had fallen more than 67 percent to 4.08 percent on average. Although the average unemployment rate in DENC's service territory has historically been above the national and North Carolina statewide averages, the correlation among the series is high. From 2005 through December 2023, the correlation

64 Source: Bureau of Labor Statistics.

in seasonally unadjusted unemployment rates between the counties served by DENC and the U.S., as well as North Carolina statewide, was approximately 90.85 percent and 95.59 percent, respectively. In summary, county-level unemployment (1) has fallen considerably since spiking in April 2020 and (2) is highly correlated to state and national unemployment rates.

Figure 16: Seasonally Unadjusted Unemployment Rates[65]

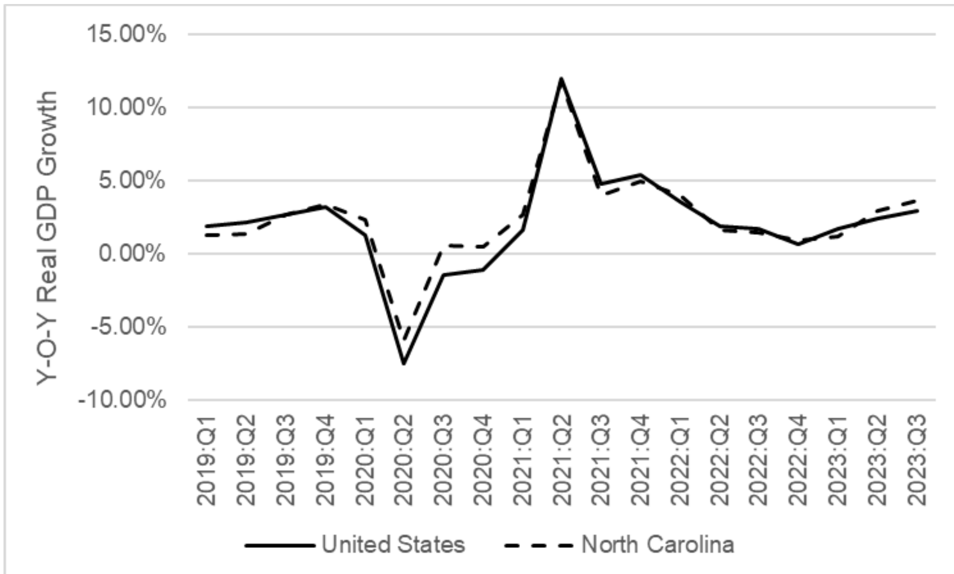


Looking to real Gross Domestic Product growth, there also has been a strong correlation between North Carolina and the national economy (approximately 97.6 percent). While the national rate of GDP growth at times outpaced North Carolina's GDP growth between 2019 and 2023, since the first quarter of 2019, North Carolina's economic growth has been highly consistent with U.S.

65 Source: Bureau of Labor Statistics.

economic growth. North Carolina's real GDP growth outperformed the U.S. economy in nine of the last 15 quarters, including in 2020.

Figure 17: Real Gross Domestic Product Growth Rate (Year over Year)[66]

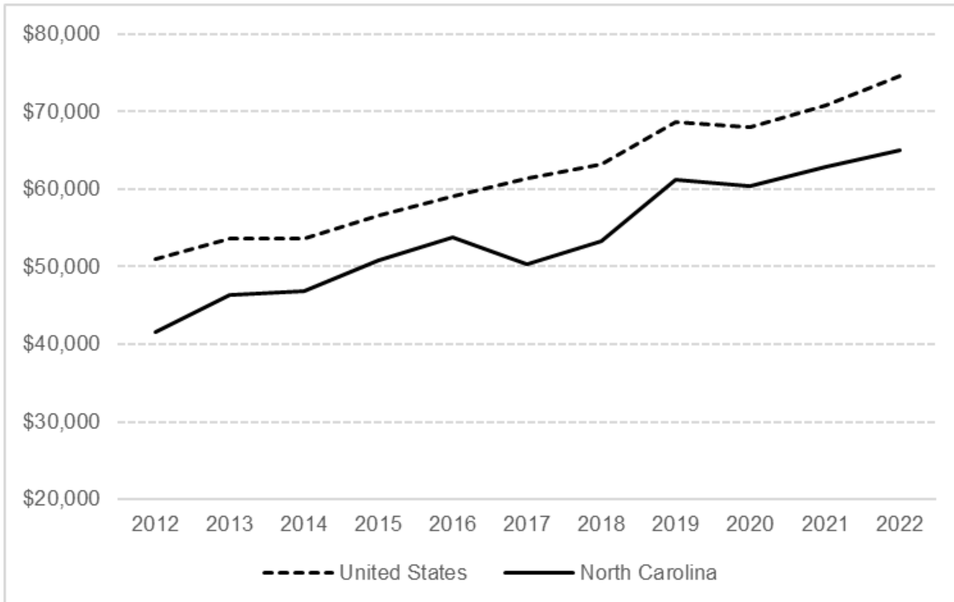


As to median household income, the correlation between North Carolina and the U.S. is strong (97.40 percent from 2012 through 2022). Since 2012, nominal median household income in North Carolina has grown at a faster pace than the national median income (compound annual growth rate of 4.59 percent vs. 3.87 percent, respectively; *see* Figure 18, below). To put household income in perspective, the Missouri Economic Research and Information Center reports that in 2023, North Carolina had the 26th lowest cost of living index among the 50 states and the District of Columbia.[67]

66 Source: Bureau of Economic Analysis.

67 Source: meric.mo.gov/data/cost-living-data-series accessed March 14, 2024.

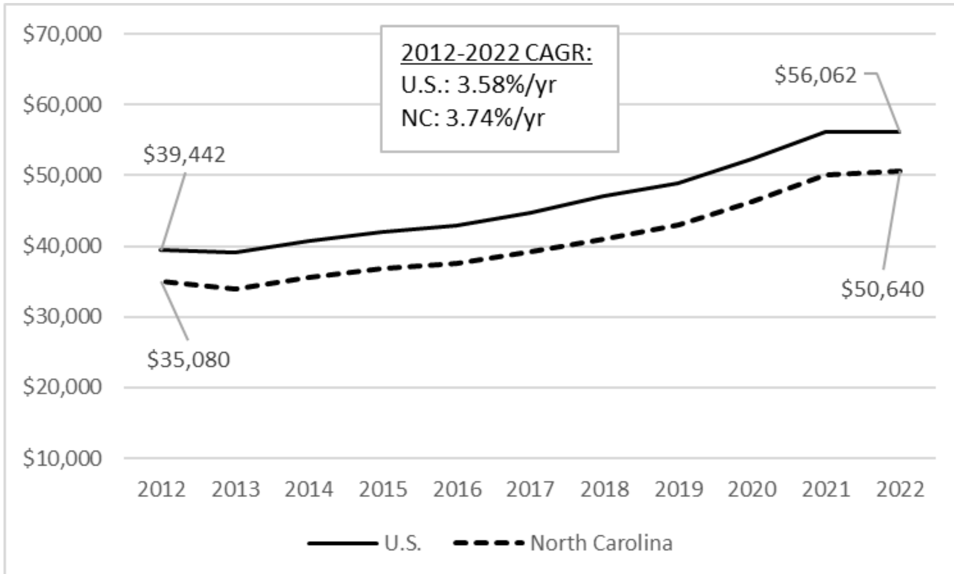
Figure 18: Median Household Income[68]



Similarly, as shown in Figure 19 below, since 2012, per capita disposable personal income has generally been on an increasing trend both nationally and in North Carolina and the two are highly correlated at 99.8 percent.

68 Source: U.S. Census Bureau, Current Population Survey Table H-8. Nominal dollars.

Figure 19: United States vs. North Carolina Per Capita Disposable Personal Income (2012-2022)[69]



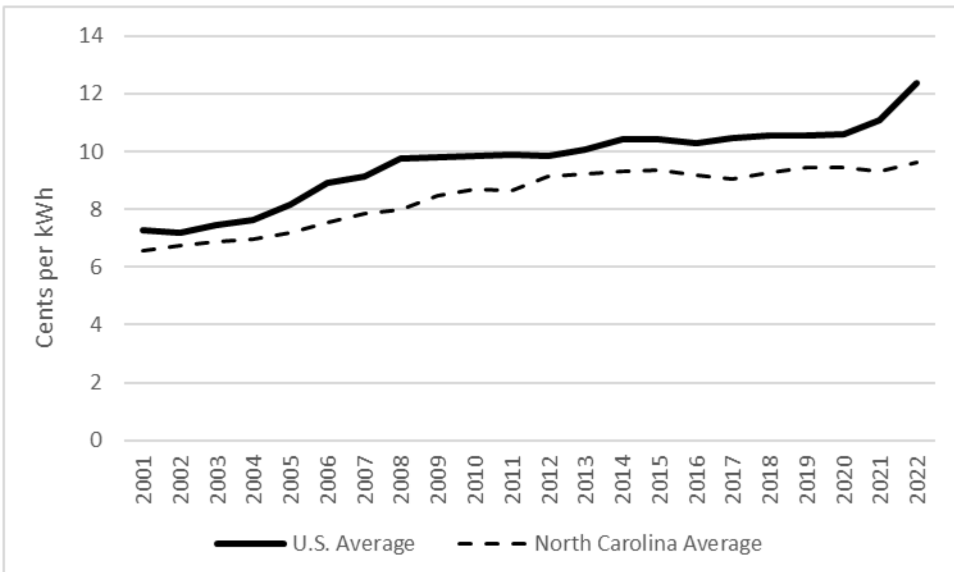
Importantly, per capita disposable personal income in North Carolina has grown at a faster pace than the U.S. overall, 3.74 percent per year on a compound average growth basis compared to 3.58 percent per year for North Carolina. On an absolute growth basis, per capita disposable personal income in North Carolina grew 44.36 percent over the last ten years vs. 42.14 percent for the U.S. Lastly, when ranked against all U.S. states and the District of Columbia, North Carolina's per capita disposable personal income was the 16th fastest growing over the last decade.

69 Source: Bureau of Economic Analysis.

Q. How do electricity prices in North Carolina compare the U.S. average?

A. As shown in Figure 20 below, according to data from the U.S. Energy Information Administration ("EIA"), the average retail price of electricity in North Carolina has been consistently lower than the U.S. average retail price of electricity over the last 20 years.

Figure 20: Average Retail Electricity Price, All Sectors (2001-2022)[70]



Further, the competitiveness of North Carolina's retail electricity prices compared to the other U.S. States has improved over the last two decades. In 2001, North Carolina's average retail electricity price ranked as the 27th lowest

70 Source: U.S. Energy Information Administration.

among the 50 U.S. states and the District of Columbia.[71] In 2022, North Carolina's average retail electricity price was the 9th lowest.[72]

Q. Please summarize the economic indicators that you analyzed and reviewed in your testimony.

A. Based on the data presented above, I observe the following:

- Unemployment at both the state and county level remains highly correlated with national rates of unemployment. North Carolina's unemployment rate and the rate in the counties served by DENC have declined significantly since spiking in April 2020;
- The state's real Gross Domestic Product is highly correlated with national GDP. On a compound annual growth basis, North Carolina's real GDP grew at a faster pace between Q3 2018 and Q3 2023;
- Since 2012, median household income has grown in North Carolina and has grown at a rate slightly faster than the national average. Additionally, the overall cost of living in North Carolina is below the national average (including the District of Columbia). Lastly, disposable personal income in North Carolina is highly correlated with the U.S. and was the 16th fastest growing over the last decade; and
- North Carolina's retail electricity prices are below the national average, and rank as the 9th lowest in the U.S. as of 2022, an improvement from 2001

71 Source: U.S. Energy Information Administration.

72 Source: U.S. Energy Information Administration.

when North Carolina had the 27th cheapest retail electricity prices.

Q. In your opinion, is an ROE of 10.60 percent fair and reasonable to DENC, its shareholders, and its customers, and not unduly burdensome to DENC's customers considering the changing economic conditions?

A. Yes. Based on the factors I have discussed here, an ROE of 10.60 percent is fair and reasonable to DENC, its shareholders, and its customers in light of the current economic conditions.

VI. CAPITAL STRUCTURE

Q. What is the Company's requested capital structure?

A. As described by Company witness Davis, the Company requests a capital structure consisting of 53.85 percent common equity and 46.15 percent long-term debt, which includes a proforma adjustment for long-term debt issued in January 2024.

Q. How does the capital structure affect the Cost of Capital?

A. A company's total risk consists of business risk and financial risk. Business risk includes operating, market, regulatory, and competitive uncertainties, while financial risk is the incremental risk associated with greater debt. As the percentage of debt in the capital structure increases, so do the fixed obligations for the repayment of that debt and the risk of financial distress.[73] Therefore,

73 *See,* Roger A. Morin, Ph.D., New Regulatory Finance, at 45-46 (2006).

the capital structure reflects the financial risk that a company may not have adequate cash flows to meet its financial obligations.

Q. Please summarize your analysis of the proxy companies' capital structures.

A. The reasonableness of DENC's requested capital structure is assessed within the context of industry practice and investor requirements. In other words, the capital structure should (1) be reasonably consistent with industry practice, (2) enable the subject company to sustain its operations and its financial integrity, and (3) allow it to maintain access to capital at competitive rates under a variety of market conditions.

To assess whether DENC's requested capital structure is consistent with industry practice, I calculated the average common equity and long-term debt ratios for each of the proxy group regulated electric operating companies over the years 2020 to 2022 (*see* Exhibit JEN-9). The mean equity ratio of the proxy group is 52.07 percent, within a range of 44.80 percent to 62.54 percent.[74] The Company's requested equity ratio of 53.85 percent is within the range of the proxy group equity ratios, and similar to the midpoint of 53.67 percent. Therefore, DENC's requested capital structure is consistent with the capital structures that finance the regulated electric operations within the proxy group.

74 Source: S&P Capital IQ.

Q. Why is it important to use average capital components over a period of time rather than a point-in-time measurement?

A. Measuring the capital components at a particular point in time can skew the capital structure by the specific circumstances of a particular period. For example, a company may issue debt to fund an acquisition or to ensure liquidity during constrained capital market environments, which may not reflect the company's long-term capital structure objectives. Therefore, it is appropriate to normalize the capital components over a period of time.

Q. What is your conclusion regarding the Company's capital structure?

A. DENC's requested common equity ratio of 53.85 percent is consistent with the proportion of equity capital that funds the regulated electric operations of the proxy group companies and is within industry standard. Further, as Company witness Davis explains, the requested capital structure is critical to the Company's ability to access capital and support its financial profile as it executes its capital expenditure plan and transition to carbon-free resources. Therefore, DENC's proposed capital structure consisting of 53.85 percent common equity and 46.15 percent long-term debt is reasonable and should be approved.

VII. CAPITAL MARKET ENVIRONMENT

Q. Do economic conditions influence the required cost of capital and required ROE?

A. Yes. The required cost of capital, including the ROE, is a function of prevailing and expected economic and capital market conditions. Each of the analytical models used to estimate the required ROE is influenced by current and expected capital market conditions. Therefore, an evaluation of current and projected market conditions is integral to any ROE recommendation.

Q. What are the key factors affecting the Cost of Equity for regulated utilities in the current and prospective capital markets?

A. The Cost of Equity for regulated utilities is currently affected by several key factors including significantly higher government and utility bond yields, persistent heightened inflation and the Federal Reserve's aggressively tighter monetary policy, and higher Beta coefficients.

Q. Please summarize the changes in capital market conditions since 2020.

A. The COVID-19 pandemic had wide ranging impacts on markets, affecting all market sectors, including utilities. At the start of the pandemic, both the S&P 500 Index and the electric utility sector lost more than a third of its value.[75] At the same time, the Chicago Board Options Exchange ("CBOE") Volatility

75 Source: Yahoo! Finance. Electric utility sector measured by the S&P 500 Electric Utilities Index.

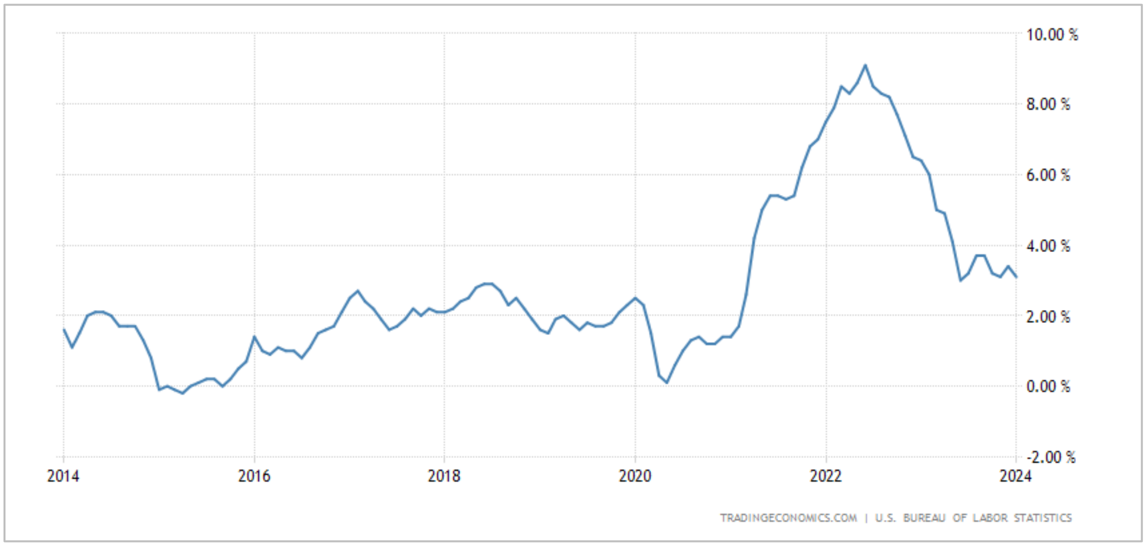
Index ("VIX", a measure of expected market volatility) tripled, from 25.03 on February 24, 2020, to 82.69 on March 16, 2020.[76]

Treasury bond yields declined rapidly as the stock market became extremely volatile and investors sought the relative safety of government bonds, combined with the Federal Reserve's lowering of the Federal Funds rate to a target range of 0 percent to 0.25 percent. Because bond yields and bond prices are inversely related, as demand for safer bonds increases, investors bid up the price of bonds, and bid down the yields. Because the decline in bond yields was caused by investors' increased aversion to equity market risk, the cost of equity did not decline commensurately with the decline in bond yields.

As the U.S. economy opened from the COVID-19 lockdowns, economic activity quickly rebounded, causing inflation to reach the highest levels seen in the last 40 years (*see* Figure 21 below). Although the pace of inflation has subsided from its peak reached in June 2022, year-over-year inflation remains stubbornly elevated and above the Federal Reserve's 2.0 percent inflation target. In fact, January 2024's inflation reported core inflation of 3.9 percent year-over-year, which was above expectations and resulted in analysts pushing back their expectations for a cut in the Federal Funds rate to later this year.

76 Source: Federal Reserve Bank of St. Louis FRED Database.

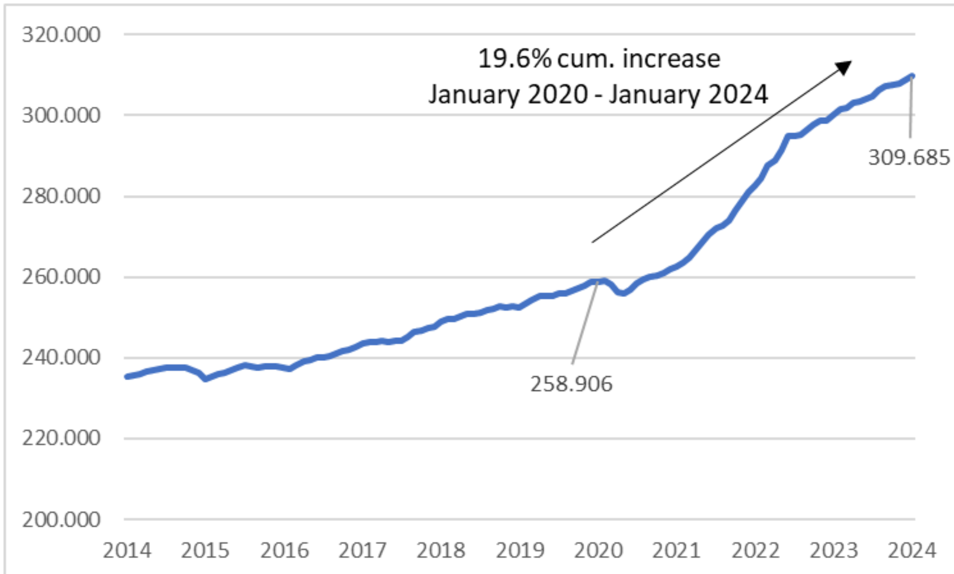
Figure 21: Year-Over-Year U.S. Consumer Price Index (2014-2024)[77]



As shown in Figure 22 below, on a cumulative basis, the CPI has increased more than 19 percent between January 2020 and January 2024.

77 Source: Trading Economics and U.S. Bureau of Labor Statistics. https://tradingeconomics.com/united-states/inflation-cpi

Figure 22: Consumer Price Index (2014 – 2024)[78]



Q. How has the Federal Reserve responded to persistent inflation?

A. With inflation surging to historically high levels in 2022, the Federal Reserve had little choice but to aggressively battle inflation with its only effective tool: Higher interest rates. In response to the economic effects of COVID-19, the Federal Reserve decreased the federal funds rate in March 2020 to a target range of 0.00 percent to 0.25 percent (which remained in effect until March 2022) in addition to other stimulus measures that increased the supply of money in the economy. The Federal Reserve began unwinding its quantitative easing program in 2022 and has thus far increased the target rate 11 times to a target rate of 5.25 percent to 5.50 percent (the highest level in the last 20 years) as shown in Figure 23 below.

78 Source: U.S. Bureau of Labor Statistics.

Figure 23: FOMC Federal Funds Rates

FOMC Meeting Date	Federal Funds Rate Change (basis points)	Target Rate
March 15, 2020		0.00% – 0.25%
March 16, 2022	25	0.25% – 0.50%
May 4, 2022	50	0.75% – 1.00%
June 15, 2022	75	1.50% – 1.75%
July 27, 2022	75	2.25% – 2.50%
September 21, 2022	75	3.00% – 3.25%
November 2, 2022	75	3.75% – 4.00%
December 14, 2022	50	4.25% – 4.50%
February 1, 2023	25	4.50% – 4.75%
March 22, 2023	25	4.75% – 5.00%
May 3, 2023	25	5.00% – 5.25%
July 26, 2023	25	5.25% – 5.50%

On January 31, 2023, Federal Reserve Chair Jerome Powell indicated that inflation remains a key consideration for the Federal Open Market Committee ("FOMC" or "Committee"):

> My colleagues and I remain squarely focused on our dual mandate to promote maximum employment and stable prices for the American people. The economy has made good progress toward our dual mandate objectives. Inflation has eased from its highs without a significant increase in unemployment. That is very good news. But inflation is still too high, ongoing progress in bringing it down is not assured, and the path forward is uncertain. I want to assure the American people that we are fully committed to returning inflation to our 2 percent goal. Restoring price stability is essential to achieve a sustained period of strong labor market conditions that benefit all.[79]

79 FOMC Press Release (January 31, 2024). Available here: https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20240131.pdf

Although year-over-year inflation rates have eased somewhat over the last few months, the Federal Reserve stated that "the economic outlook is uncertain" and that the Federal Reserve remains "highly attentive to inflation risks."[80] Although Chair Powell signaled that the Federal Reserve believes that its federal funds rate policy "is likely at its peak for this tightening cycle," he cautioned that the Committee is "prepared to maintain the current target range for the federal funds rate for longer, if appropriate."[81] As noted earlier, stronger than expected inflation in January has prompted Federal Reserve officials to signal that a rate cut may not occur until later this year.

Q. How have government and utility bond yields responded to the Federal Reserve's monetary policy tightening?

A. As the U.S. economy improved in 2021 and the Federal Reserve moved aggressively to tighten monetary policy to fight stubbornly higher inflation, prevailing interest rates have risen to their highest levels since 2010.[82] As shown in Figure 24 below, the 30-year Treasury yield has increased 222 basis points since November 3, 2021 when the Federal Reserve signaled it would begin tapering its asset purchases. Utility bond yields have increased by nearly 240 basis points over the same period.

---

80 FOMC Press Release (January 31, 2024). Available here: https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20240131.pdf

81 FOMC Press Release (January 31, 2024). Available here: https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20240131.pdf

82 Source: Federal Reserve Bank of St. Louis, FRED Economic Database.

Figure 24: 30-Year Treasury Bond and Utility Bond Yields (2018-2023)[83]

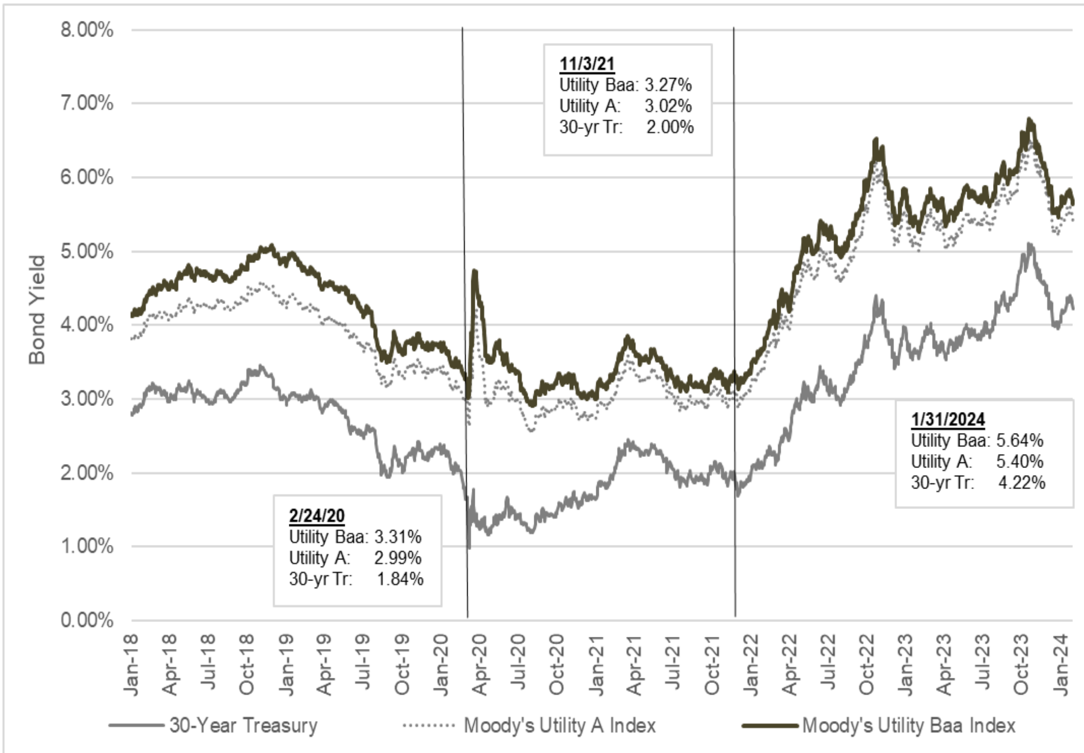


Figure 24 also illustrates the significant increase in the interest rate environment since the Commission's order in DENC's last rate case. The 30-year Treasury bond yield and investment grade utility bond yields have each increased more than 230 basis points.

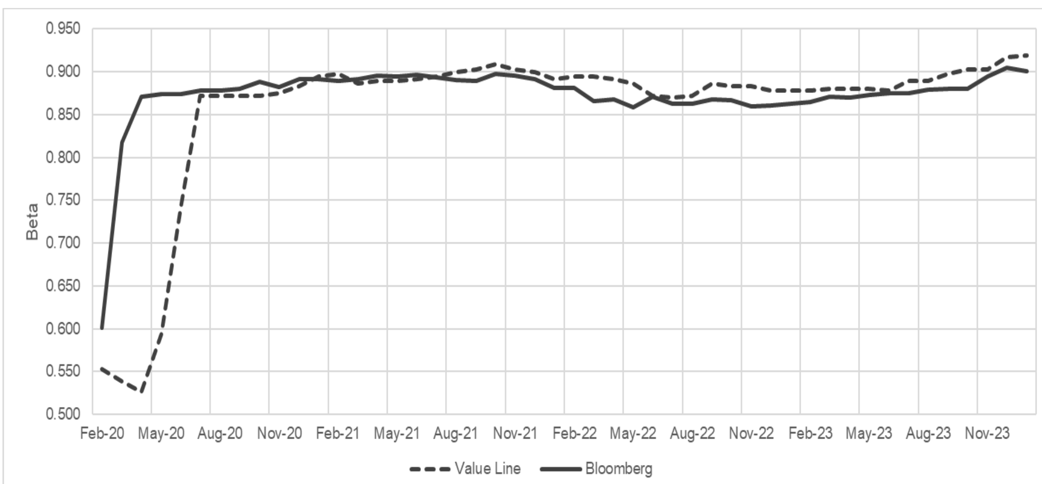
Q. Are there additional indications that the Cost of Equity has increased for utilities?

A. Yes. As explained in Section III, the Beta coefficient is a measure of a company's systematic risk relative to the overall market. Under the CAPM, higher Beta coefficients indicate an increase in the Cost of Equity, all else equal.

83 Source: Federal Reserve Bank of St. Louis, FRED Economic Database; Bloomberg Professional.

As shown in Figure 25, below, the average Bloomberg and *Value Line* 5-year Beta coefficients for the proxy group increased approximately 49.90 and 66.28 percent, respectively between February 2020 and January 2024. In other words, investors have not viewed the utility sector as a “safe-haven” since the onset of the COVID-19 pandemic. Even though bond yields declined in 2020 and 2021, utility equity risk increased.

Figure 25: *Value Line* and Bloomberg Proxy Group Average Beta Coefficients[84]



Q. How have utility stocks performed relative to the market in recent months?

A. A recent S&P Global report notes that the utility sector “consistently underperformed the S&P 500” in 2023, due in part to higher interest rates.[85] As shown in Figure 26 below, while the broad S&P 500 Index market saw a total

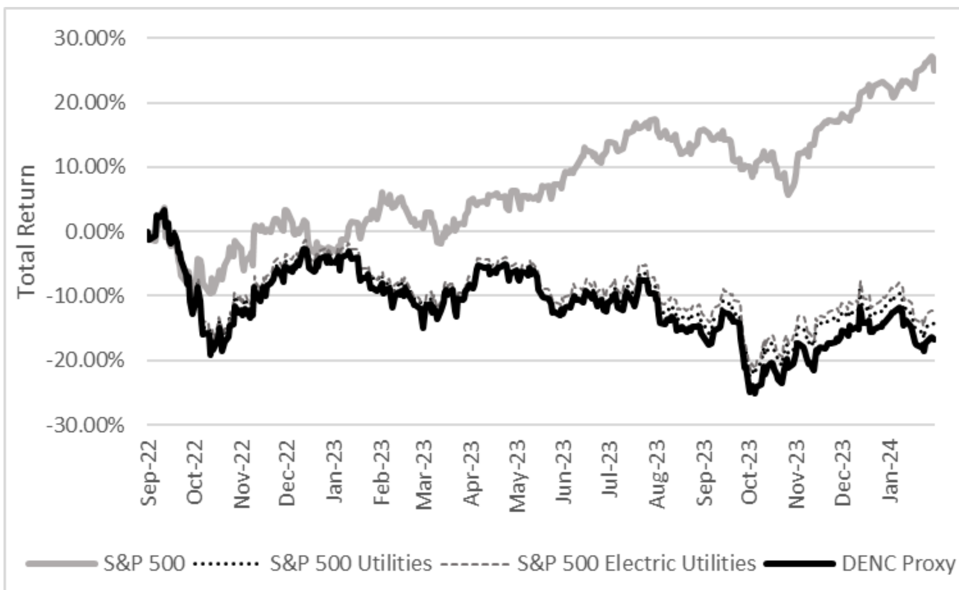
84 Sources: *Value Line* and Bloomberg Professional Service at month end from February 28, 2020 through January 31, 2024.

85 S&P Global Market Intelligence. “US electric utility stocks finish 2023 with losses; NRG leads sector gains,” January 5, 2024.

return of 25.00 percent between September 30, 2022 and January 31, 2024, the S&P 500 Electric Utilities and S&P 500 Utilities indices saw a contraction of approximately 12.63 percent and 14.46 percent, respectively, over that period. The proxy group saw an even more pronounced contraction over that period of 16.73 percent.

Figure 26: Total Return of the Proxy Group vs. S&P 500 Indices

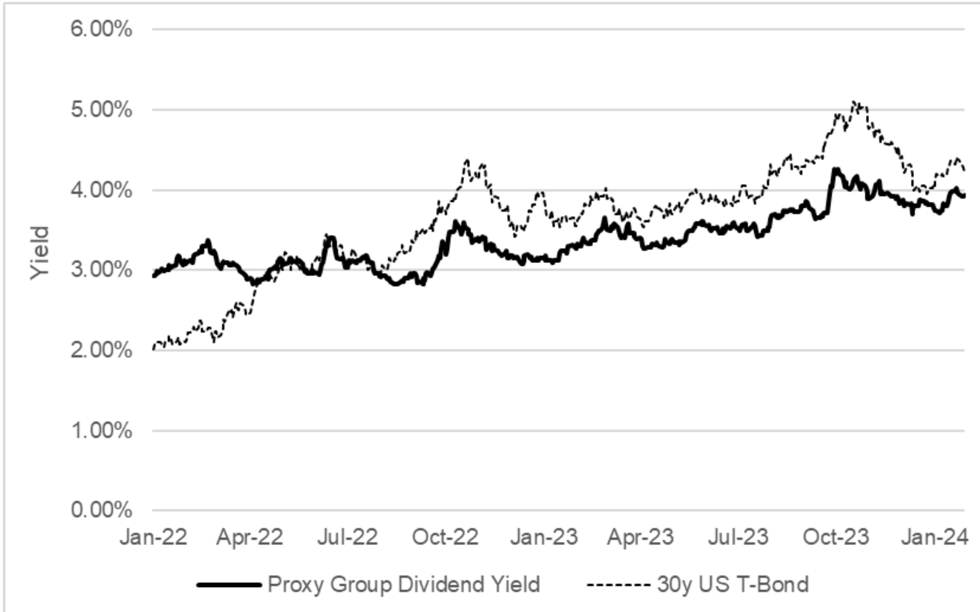
(September 2022 – January 2024)[86]



Further, as capital-intensive enterprises that rely heavily on external capital, utility stock prices are inversely related to interest rates. That is, as interest rates rise, utility stock prices tend to decline and vice versa. Moreover, Treasury securities have recently offered yields equal to or even higher than utility dividend yields (*see* Figure 27 below).

86 S&P Capital IQ.

Figure 27: Proxy Group Dividend Yield vs. 30-year Treasury Bond Yield (January 2022 – January 2024)[87]



Stable and attractive dividend yields are one reason utilities are generally considered as defensive stocks relative to other securities and sectors. However, when safer government bonds are offering more attractive yields, investors that value yield may shift capital to less risky government bonds, pushing down equity prices and increasing dividend yields. All else equal, higher dividend yields indicate a higher cost of equity. This evidence illustrates the effect that historic interest rates and inflation have had on the utility stocks over the past year.

87 Source: S&P Capital IQ.

Q. What conclusions do you draw from your review of the current capital market environment and its implications on the Company's Cost of Equity?

A. Over the last four years, the economic and financial market environment has operated under heightened uncertainty associated with the COVID-19 pandemic, the war in Ukraine, inflation, and more recently, uncertainty surrounding the economy and in the timing of the Federal Reserve's monetary policy. Observable market data make clear that utility investors face greater risks than prior to the onset of the COVID-19 pandemic. Short- and long-term interest rates have increased substantially since the DENC's last rate case. All these factors indicate an increase in the Cost of Equity.

VIII. CONCLUSIONS

Q. What are your conclusions regarding the ROE and capital structure for DENC?

A. Based on the quantitative results from three commonly used analytical approaches, I conclude an ROE in the range of 9.90 percent to 11.40 percent represents the range of equity investors' required ROE for investment in a regulated electric utility of similar risk to DENC. Within that range, I conclude that an ROE of 10.60 percent enables DENC to attract capital at reasonable terms, and allows it to support and maintain its financial integrity. Further, my conclusion considers DENC's capital financing needs, the regulatory environment in which it operates, its capital structure, the economic conditions in North Carolina, and the current capital market environment.

As to the capital structure, DENC's capital structure consisting of 53.85 percent common equity and 46.15 percent long-term debt is consistent with the capital structures that finance the regulated electric operations of the proxy companies. Therefore, I recommend the Commission approve the Company's requested capital structure.

Q. Does this conclude your direct testimony?

A. Yes.

JENNIFER E. NELSON
ASSISTANT VICE PRESIDENT

Ms. Nelson is a Certified Rate of Return Analyst with fifteen years of experience in the energy industry. As an expert witness, she has testified to the cost of capital and alternative ratemaking proposals for electric, natural gas, and water utilities. In her time as a consultant, Ms. Nelson has provided consulting services on a variety of utility regulatory matters including ratemaking and regulatory policy, cost of service and revenue requirements, integrated resource planning, renewable power contracts, natural gas pipeline development, utility supply planning issues, and merger and acquisition transactions. Ms. Nelson has extensive experience performing statistical analyses, developing economic and financial models, and providing policy analyses and recommendations.

Prior to joining Concentric, Ms. Nelson was a Director at ScottMadden, Inc., and a managing consultant at Sussex Economic Advisors, LLC. Prior to consulting, she was a staff economist at the Massachusetts Department of Public Utilities and a petroleum economist for the State of Alaska. Ms. Nelson holds a Master of Science degree in Resource and Applied Economics from the University of Alaska and a Bachelor of Science degree in Business Economics from Bentley University.

AREAS OF EXPERTISE

Cost of Capital

- Submitted expert testimony on behalf of electric utilities before regulatory commissions in Arkansas, New Hampshire, New Mexico, and Texas regarding the cost of capital.
- Submitted expert testimony on behalf of natural gas utilities before regulatory commissions in Florida, North Carolina, Ohio, South Carolina, Utah, West Virginia, and Wyoming regarding the cost of capital.
- Submitted expert testimony on behalf of a water utility before the Kentucky Public Service Commission regarding the appropriate capital structure and cost of debt.
- Supported expert testimony regarding the cost of capital before numerous state utility regulatory commissions and the FERC on behalf of electric and natural gas utilities through research, financial analysis and modeling, and testimony development.

Alternative Ratemaking Mechanisms

- Submitted expert testimony on behalf of electric utilities and a water utility before the Arkansas Public Service Commission regarding the utilities' proposed Formula Rate Plans.
- Submitted expert testimony on behalf of an electric utility before the Oklahoma Corporation Commission regarding the utility's proposed Formula Rate Plan.
- Submitted expert testimony on behalf of an electric and natural gas utility before the Montana Public Service Commission regarding the utility's proposed alternative rate mechanisms.

- Co-sponsored expert testimony on behalf of a natural gas utility before the Maine Public Utilities Commission regarding the utility's proposed capital investment cost recovery mechanism.
- Supported expert testimony and performed research and analysis on alternative ratemaking frameworks.

Resource and Supply Planning

- Supported expert testimony on the reasonableness of utility resource supply portfolio decisions.
- Assisted in a benchmarking analysis on behalf of a Northeast U.S. natural gas utility regarding its supply planning standards and design day demand forecast process.
- Supported rebuttal testimony filed on behalf of an Alaska natural gas utility regarding the utility's gas supply planning standards.
- Supported the development of a New Hampshire electric utility's Integrated Resource Plan filed with the New Hampshire Public Utility Commission.
- Performed research and financial analysis to evaluate the benefits, costs, and policy options associated with natural gas expansion by Massachusetts natural gas utilities as part of a prepared report for the Massachusetts Department of Energy Resources.
- Developed a dynamic natural gas demand forecast model for in-state use for the State of Alaska, which included forecasting demand from both existing and anticipated natural gas utilities, power consumption, and large commercial operations.
- Conducted research and prepared analyses for a natural gas pipeline Open Season.

Other Regulatory Financial Issues

- Supported expert testimony on the appropriate level of remuneration associated with the Massachusetts electric utilities' long-term contracts for wind power through research, financial analysis and modeling, and testimony development.
- Provided research and analytical support estimating financial damages incurred as a result of construction delays for an electric transmission company.
- Prepared a Feasibility Study for an electric cooperative utility supporting a utility-owned solar project.

Mergers & Acquisitions

- Performed buy-side benchmarking and regulatory analysis for utility acquisitions.

RELEVANT PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2021-present)
Assistant Vice President

ScottMadden, Inc. (2016-2021)
Director
Manager

Sussex Economic Advisors, LLC (2013-2016)
Managing Consultant

Massachusetts Department of Public Utilities (2011-2013)
Economist, Electric Power Division

State of Alaska Department of Revenue, Tax Division (2007-2010)
Petroleum Economist

Federal Reserve Bank of Boston (2000-2002)
Research Assistant, Economic Research Department

EDUCATION AND RELEVANT COURSEWORK

University of Alaska
Master of Science, Resource and Applied Economics

Bentley University (formerly Bentley College)
Bachelor of Science, Business Economics
Graduated *magna cum laude*

New Mexico State University
Center for Public Utilities, Regulatory Basics

ISO New England
Wholesale Energy Markets (WEM-101)

Colorado School of Mines
Petroleum Engineering SuperSchool

EUCI
Course Instructor – Performance-Based Ratemaking

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts
Member, Society of Utility and Regulatory Financial Analysts

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Arkansas Public Service Commission				
Oklahoma Gas & Electric	10/21	Oklahoma Gas & Electric	21-087-U	Formula Rate Plan
Liberty Utilities (Pine Bluff Water)	10/18	Liberty Utilities (Pine Bluff Water)	18-027-U	Formula Rate Plan and tariff
Entergy Arkansas, LLC	11/20	Entergy Arkansas, LLC	16-036-FR	Sponsored testimony evaluating the Return on Equity included in Rider FRP
Florida Public Service Commission				
Pivotal Utility Holdings, Inc. d/b/a Florida City Gas	05/22	Pivotal Utility Holdings, Inc. d/b/a Florida City Gas	20220069-GU	Cost of Capital
Kentucky Public Service Commission				
Bluegrass Water Utility Operating Company, LLC	09/20	Bluegrass Water Utility Operating Company, LLC	2020-290	Capital Structure and Cost of Long-Term Debt
Maine Public Utilities Commission				
Unitil Corporation	06/19	Northern Utilities, Inc.	19-00092	Co-sponsored testimony supporting a proposed CIRA capital tracking mechanism
Montana Public Utilities Commission				
NorthWestern Corporation	08/22	NorthWestern Corporation	2022-7-78 (elect.) 2022-7-78 (gas)	Alternative Ratemaking Proposals
New Hampshire Public Utilities Commission				
Unitil Energy Systems, Inc.	04/21	Unitil Energy Systems, Inc.	DE 21-030	Cost of Capital
New Mexico Public Regulation Commission				
El Paso Electric Company	07/20	El Paso Electric Company	20-00104-UT	Cost of Capital
North Carolina Utilities Commission				
Public Service Company of North Carolina d/b/a Dominion Energy North Carolina	04/21	Public Service Company of North Carolina d/b/a Dominion Energy North Carolina	G-5, Sub 632	Cost of Capital
Public Utilities Commission of Ohio				

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
The East Ohio Gas Company d/b/a Dominion Energy Ohio	11/23	The East Ohio Gas Company d/b/a Dominion Energy Ohio	23-0894-GA-AIR	Cost of Capital
Oklahoma Corporation Commission				
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	PUD202100164	Formula Rate Plan
Public Utility Commission of Oregon				
Northwest Natural Gas Company dba NW Natural	12/23	Northwest Natural Gas Company dba NW Natural	UG 490	Cost of Capital
Public Utilities Commission of South Carolina				
Dominion Energy South Carolina	03/24	Dominion Energy South Carolina	2024-34-E	Cost of Capital
Dominion Energy South Carolina	04/23	Dominion Energy South Carolina	2023-70-G	Cost of Capital
Public Utilities Commission of Texas				
El Paso Electric Company	06/21	El Paso Electric Company	52195	Cost of Capital
Sharyland Utilities L.L.C.	12/20	Sharyland Utilities L.L.C.	51611	Cost of Capital
Utah Public Service Commission				
Dominion Energy Utah	05/22	Dominion Energy Utah	22-057-03	Cost of Capital
Public Service Commission of West Virginia				
Hope Gas, Inc. d/b/a Dominion Energy West Virginia	11/20	Hope Gas, Inc. d/b/a Dominion Energy West Virginia	20-0746-G-42T	Cost of Capital
Wyoming Public Service Commission				
Dominion Energy Wyoming	03/23	Dominion Energy Wyoming	30010-215-GR-23	Cost of Capital

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
30 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] Yahoo! Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
Alliant Energy Corporation	LNT	$1.92	$50.34	3.81%	3.94%	6.20%	6.55%	6.50%	6.42%	10.13%	10.35%	10.49%
Ameren Corporation	AEE	$2.52	$71.51	3.52%	3.63%	5.90%	4.80%	6.50%	5.73%	8.41%	9.36%	10.14%
American Electric Power Company, Inc.	AEP	$3.52	$80.52	4.37%	4.49%	5.10%	4.20%	6.50%	5.27%	8.66%	9.75%	11.01%
Avista Corporation	AVA	$1.84	$35.05	5.25%	5.41%	6.20%	6.20%	6.00%	6.13%	11.41%	11.54%	11.61%
CMS Energy Corporation	CMS	$1.95	$57.71	3.38%	3.50%	7.50%	7.70%	5.50%	6.90%	8.97%	10.40%	11.21%
DTE Energy Company	DTE	$4.08	$107.95	3.78%	3.88%	6.00%	5.10%	4.50%	5.20%	8.36%	9.08%	9.89%
Duke Energy Corporation	DUK	$4.10	$96.90	4.23%	4.36%	6.30%	6.55%	5.00%	5.95%	9.34%	10.31%	10.92%
Edison International	EIX	$3.12	$69.89	4.46%	4.56%	3.70%	4.60%	4.50%	4.27%	8.25%	8.83%	9.17%
Entergy Corporation	ETR	$4.52	$101.03	4.47%	4.61%	7.00%	11.00%	0.50%	6.17%	4.99%	10.78%	15.72%
Evergy, Inc.	EVRG	$2.57	$51.87	4.95%	5.07%	4.30%	2.50%	7.50%	4.77%	7.52%	9.84%	12.64%
IDACORP, Inc.	IDA	$3.32	$95.88	3.46%	3.54%	4.40%	4.40%	4.00%	4.27%	7.53%	7.80%	7.94%
NextEra Energy, Inc.	NEE	$1.87	$59.98	3.12%	3.25%	8.20%	7.81%	9.50%	8.50%	11.05%	11.75%	12.77%
NorthWestern Energy Group, Inc.	NWE	$2.56	$49.78	5.14%	5.25%	5.20%	4.08%	3.50%	4.26%	8.73%	9.51%	10.48%
OGE Energy Corporation	OGE	$1.67	$34.31	4.88%	5.00%	4.00%	negative	6.50%	5.25%	8.97%	10.25%	11.53%
Pinnacle West Capital Corporation	PNW	$3.52	$71.36	4.93%	5.04%	4.00%	5.90%	2.50%	4.13%	7.49%	9.17%	10.98%
Portland General Electric Company	POR	$1.90	$42.33	4.49%	4.61%	6.00%	4.60%	5.00%	5.20%	9.19%	9.81%	10.62%
Southern Company	SO	$2.80	$70.15	3.99%	4.11%	4.00%	7.10%	6.50%	5.87%	8.07%	9.98%	11.23%
Xcel Energy Inc.	XEL	$2.08	$61.25	3.40%	3.50%	6.00%	6.57%	6.00%	6.19%	9.50%	9.69%	10.08%
Proxy Group Mean				4.20%	4.32%	5.56%	5.86%	5.36%	5.58%	8.70%	9.90%	11.02%
Proxy Group Median				4.30%	4.42%	5.95%	5.90%	5.75%	5.50%	8.70%	9.82%	10.95%
Average of Mean and Median				4.25%	4.37%	5.75%	5.88%	5.56%	5.54%	8.70%	9.86%	10.99%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of 01/31/2024
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
90 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] Yahoo! Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
Alliant Energy Corporation	LNT	$1.92	$49.90	3.85%	3.97%	6.20%	6.55%	6.50%	6.42%	10.17%	10.39%	10.52%
Ameren Corporation	AEE	$2.52	$75.01	3.36%	3.46%	5.90%	4.80%	6.50%	5.73%	8.24%	9.19%	9.97%
American Electric Power Company, Inc.	AEP	$3.52	$78.19	4.50%	4.62%	5.10%	4.20%	6.50%	5.27%	8.80%	9.89%	11.15%
Avista Corporation	AVA	$1.84	$34.03	5.41%	5.57%	6.20%	6.20%	6.00%	6.13%	11.57%	11.71%	11.77%
CMS Energy Corporation	CMS	$1.95	$56.19	3.47%	3.59%	7.50%	7.70%	5.50%	6.90%	9.07%	10.49%	11.30%
DTE Energy Company	DTE	$4.08	$103.51	3.94%	4.04%	6.00%	5.10%	4.50%	5.20%	8.53%	9.24%	10.06%
Duke Energy Corporation	DUK	$4.10	$92.36	4.44%	4.57%	6.30%	6.55%	5.00%	5.95%	9.55%	10.52%	11.13%
Edison International	EIX	$3.12	$66.62	4.68%	4.78%	3.70%	4.60%	4.50%	4.27%	8.47%	9.05%	9.39%
Entergy Corporation	ETR	$4.52	$98.22	4.60%	4.74%	7.00%	11.00%	0.50%	6.17%	5.11%	10.91%	15.86%
Evergy, Inc.	EVRG	$2.57	$50.80	5.06%	5.18%	4.30%	2.50%	7.50%	4.77%	7.62%	9.95%	12.75%
IDACORP, Inc.	IDA	$3.32	$96.32	3.45%	3.52%	4.40%	4.40%	4.00%	4.27%	7.52%	7.79%	7.92%
NextEra Energy, Inc.	NEE	$1.87	$58.00	3.22%	3.36%	8.20%	7.81%	9.50%	8.50%	11.16%	11.86%	12.88%
NorthWestern Energy Group, Inc.	NWE	$2.56	$49.69	5.15%	5.26%	5.20%	4.08%	3.50%	4.26%	8.74%	9.52%	10.49%
OGE Energy Corporation	OGE	$1.67	$34.35	4.87%	5.00%	4.00%	negative	6.50%	5.25%	8.97%	10.25%	11.53%
Pinnacle West Capital Corporation	PNW	$3.52	$73.08	4.82%	4.92%	4.00%	5.90%	2.50%	4.13%	7.38%	9.05%	10.86%
Portland General Electric Company	POR	$1.90	$41.62	4.56%	4.68%	6.00%	4.60%	5.00%	5.20%	9.27%	9.88%	10.70%
Southern Company	SO	$2.80	$68.91	4.06%	4.18%	4.00%	7.10%	6.50%	5.87%	8.14%	10.05%	11.31%
Xcel Energy Inc.	XEL	$2.08	$60.09	3.46%	3.57%	6.00%	6.57%	6.00%	6.19%	9.57%	9.76%	10.14%
Proxy Group Mean				4.27%	4.39%	5.56%	5.86%	5.36%	5.58%	8.77%	9.97%	11.10%
Proxy Group Median				4.47%	4.60%	5.95%	5.90%	5.75%	5.50%	8.77%	9.92%	11.00%
Average of Mean and Median				4.37%	4.49%	5.75%	5.88%	5.56%	5.54%	8.77%	9.94%	11.05%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of 01/31/2024
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
180 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] Yahoo! Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
Alliant Energy Corporation	LNT	$1.92	$51.08	3.76%	3.88%	6.20%	6.55%	6.50%	6.42%	10.08%	10.30%	10.43%
Ameren Corporation	AEE	$2.52	$78.59	3.21%	3.30%	5.90%	4.80%	6.50%	5.73%	8.08%	9.03%	9.81%
American Electric Power Company, Inc.	AEP	$3.52	$80.50	4.37%	4.49%	5.10%	4.20%	6.50%	5.27%	8.66%	9.75%	11.01%
Avista Corporation	AVA	$1.84	$35.95	5.12%	5.28%	6.20%	6.20%	6.00%	6.13%	11.27%	11.41%	11.48%
CMS Energy Corporation	CMS	$1.95	$57.41	3.40%	3.51%	7.50%	7.70%	5.50%	6.90%	8.99%	10.41%	11.23%
DTE Energy Company	DTE	$4.08	$106.22	3.84%	3.94%	6.00%	5.10%	4.50%	5.20%	8.43%	9.14%	9.96%
Duke Energy Corporation	DUK	$4.10	$91.90	4.46%	4.59%	6.30%	6.55%	5.00%	5.95%	9.57%	10.54%	11.16%
Edison International	EIX	$3.12	$68.01	4.59%	4.69%	3.70%	4.60%	4.50%	4.27%	8.37%	8.95%	9.29%
Entergy Corporation	ETR	$4.52	$98.41	4.59%	4.73%	7.00%	11.00%	0.50%	6.17%	5.10%	10.90%	15.85%
Evergy, Inc.	EVRG	$2.57	$54.31	4.73%	4.84%	4.30%	2.50%	7.50%	4.77%	7.29%	9.61%	12.41%
IDACORP, Inc.	IDA	$3.32	$98.73	3.36%	3.43%	4.40%	4.40%	4.00%	4.27%	7.43%	7.70%	7.84%
NextEra Energy, Inc.	NEE	$1.87	$64.77	2.89%	3.01%	8.20%	7.81%	9.50%	8.50%	10.81%	11.51%	12.52%
NorthWestern Energy Group, Inc.	NWE	$2.56	$52.46	4.88%	4.98%	5.20%	4.08%	3.50%	4.26%	8.47%	9.24%	10.21%
OGE Energy Corporation	OGE	$1.67	$34.91	4.79%	4.92%	4.00%	negative	6.50%	5.25%	8.89%	10.17%	11.45%
Pinnacle West Capital Corporation	PNW	$3.52	$76.44	4.60%	4.70%	4.00%	5.90%	2.50%	4.13%	7.16%	8.83%	10.64%
Portland General Electric Company	POR	$1.90	$44.20	4.30%	4.41%	6.00%	4.60%	5.00%	5.20%	9.00%	9.61%	10.43%
Southern Company	SO	$2.80	$69.45	4.03%	4.15%	4.00%	7.10%	6.50%	5.87%	8.11%	10.02%	11.27%
Xcel Energy Inc.	XEL	$2.08	$60.88	3.42%	3.52%	6.00%	6.57%	6.00%	6.19%	9.52%	9.71%	10.10%
Proxy Group Mean				4.13%	4.24%	5.56%	5.86%	5.36%	5.58%	8.62%	9.83%	10.95%
Proxy Group Median				4.34%	4.45%	5.95%	5.90%	5.75%	5.50%	8.57%	9.73%	10.83%
Average of Mean and Median				4.23%	4.35%	5.75%	5.88%	5.56%	5.54%	8.59%	9.78%	10.89%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of 01/31/2024
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Quarterly Growth Discounted Cash Flow Model
30 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Company	Ticker	Dividend 1	Dividend 2	Dividend 3	Dividend 4	Expected Dividend 1	Expected Dividend 2	Expected Dividend 3	Expected Dividend 4	Average Stock Price	Zacks Earnings Growth	Yahoo! Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
Alliant Energy Corporation	LNT	$0.45	$0.45	$0.45	$0.48	$0.48	$0.48	$0.48	$0.51	$50.34	6.20%	6.55%	6.50%	6.42%	10.22%	10.45%	10.59%
Ameren Corporation	AEE	$0.63	$0.63	$0.63	$0.63	$0.67	$0.67	$0.67	$0.67	$71.51	5.90%	4.80%	6.50%	5.73%	8.61%	9.59%	10.40%
American Electric Power Company, Inc.	AEP	$0.83	$0.83	$0.83	$0.88	$0.87	$0.87	$0.87	$0.93	$80.52	5.10%	4.20%	6.50%	5.27%	8.70%	9.83%	11.14%
Avista Corporation	AVA	$0.46	$0.46	$0.46	$0.46	$0.49	$0.49	$0.49	$0.49	$35.05	6.20%	6.20%	6.00%	6.13%	11.81%	11.95%	12.02%
CMS Energy Corporation	CMS	$0.49	$0.49	$0.49	$0.49	$0.52	$0.52	$0.52	$0.52	$57.71	7.50%	7.70%	5.50%	6.90%	9.19%	10.65%	11.49%
DTE Energy Company	DTE	$0.95	$0.95	$0.95	$1.02	$1.00	$1.00	$1.00	$1.07	$107.95	6.00%	5.10%	4.50%	5.20%	8.37%	9.10%	9.94%
Duke Energy Corporation	DUK	$1.01	$1.01	$1.03	$1.03	$1.06	$1.06	$1.09	$1.09	$96.90	6.30%	6.55%	5.00%	5.95%	9.55%	10.56%	11.20%
Edison International	EIX	$0.74	$0.74	$0.74	$0.78	$0.77	$0.77	$0.77	$0.81	$69.89	3.70%	4.60%	4.50%	4.27%	8.27%	8.88%	9.23%
Entergy Corporation	ETR	$1.07	$1.07	$1.07	$1.13	$1.14	$1.14	$1.14	$1.20	$101.03	7.00%	11.00%	0.50%	6.17%	4.89%	10.91%	16.04%
Evergy, Inc.	EVRG	$0.61	$0.61	$0.61	$0.64	$0.64	$0.64	$0.64	$0.67	$51.87	4.30%	2.50%	7.50%	4.77%	7.54%	9.96%	12.88%
IDACORP, Inc.	IDA	$0.79	$0.79	$0.79	$0.83	$0.82	$0.82	$0.82	$0.87	$95.88	4.40%	4.40%	4.00%	4.27%	7.57%	7.85%	7.99%
NextEra Energy, Inc.	NEE	$0.47	$0.47	$0.47	$0.47	$0.51	$0.51	$0.51	$0.51	$59.98	8.20%	7.81%	9.50%	8.50%	11.31%	12.04%	13.08%
NorthWestern Energy Group, Inc.	NWE	$0.64	$0.64	$0.64	$0.64	$0.67	$0.67	$0.67	$0.67	$49.78	5.20%	4.08%	3.50%	4.26%	9.00%	9.82%	10.83%
OGE Energy Corporation	OGE	$0.41	$0.41	$0.42	$0.42	$0.44	$0.44	$0.44	$0.44	$34.31	4.00%	negative	6.50%	5.25%	9.22%	10.55%	11.89%
Pinnacle West Capital Corporation	PNW	$0.87	$0.87	$0.88	$0.88	$0.90	$0.90	$0.92	$0.92	$71.36	4.00%	5.90%	2.50%	4.13%	7.65%	9.40%	11.29%
Portland General Electric Company	POR	$0.45	$0.48	$0.48	$0.48	$0.48	$0.50	$0.50	$0.50	$42.33	6.00%	4.60%	5.00%	5.20%	9.40%	10.04%	10.89%
Southern Company	SO	$0.68	$0.70	$0.70	$0.70	$0.72	$0.74	$0.74	$0.74	$70.15	4.00%	7.10%	6.50%	5.87%	8.25%	10.22%	11.52%
Xcel Energy Inc.	XEL	$0.52	$0.52	$0.52	$0.52	$0.55	$0.55	$0.55	$0.55	$61.25	6.00%	6.57%	6.00%	6.19%	9.73%	9.93%	10.33%
Proxy Group Mean											5.56%	5.86%	5.36%	5.58%	8.85%	10.09%	11.26%
Proxy Group Median											5.95%	5.90%	5.75%	5.50%	8.85%	10.00%	11.17%
Average of Mean and Median															8.85%	10.05%	11.21%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service
[3] Source: Bloomberg Professional Service
[4] Source: Bloomberg Professional Service
[5] Equals Col. [1] x (1 + Col. [13])
[6] Equals Col. [2] x (1 + Col. [13])
[7] Equals Col. [3] x (1 + Col. [13])
[8] Equals Col. [4] x (1 + Col. [13])
[9] Source: Bloomberg Professional, equals indicated number of trading day average as of 01/31/2024
[10] Source: Zacks
[11] Source: Yahoo! Finance
[12] Source: Value Line
[13] Equals Average (Cols. [10], [11], [12])
[14] Implied Low DCF
[15] Implied Mean DCF
[16] Implied High DCF

Quarterly Growth Discounted Cash Flow Model
90 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Company	Ticker	Dividend 1	Dividend 2	Dividend 3	Dividend 4	Expected Dividend 1	Expected Dividend 2	Expected Dividend 3	Expected Dividend 4	Average Stock Price	Zacks Earnings Growth	Yahoo! Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
Alliant Energy Corporation	LNT	$0.45	$0.45	$0.45	$0.48	$0.48	$0.48	$0.48	$0.51	$49.90	6.20%	6.55%	6.50%	6.42%	10.26%	10.48%	10.62%
Ameren Corporation	AEE	$0.63	$0.63	$0.63	$0.63	$0.67	$0.67	$0.67	$0.67	$75.01	5.90%	4.80%	6.50%	5.73%	8.43%	9.41%	10.21%
American Electric Power Company, Inc.	AEP	$0.83	$0.83	$0.83	$0.88	$0.87	$0.87	$0.87	$0.93	$78.19	5.10%	4.20%	6.50%	5.27%	8.84%	9.97%	11.28%
Avista Corporation	AVA	$0.46	$0.46	$0.46	$0.46	$0.49	$0.49	$0.49	$0.49	$34.03	6.20%	6.20%	6.00%	6.13%	11.98%	12.13%	12.20%
CMS Energy Corporation	CMS	$0.49	$0.49	$0.49	$0.49	$0.52	$0.52	$0.52	$0.52	$56.19	7.50%	7.70%	5.50%	6.90%	9.29%	10.76%	11.60%
DTE Energy Company	DTE	$0.95	$0.95	$0.95	$1.02	$1.00	$1.00	$1.00	$1.07	$103.51	6.00%	5.10%	4.50%	5.20%	8.54%	9.27%	10.12%
Duke Energy Corporation	DUK	$1.01	$1.01	$1.03	$1.03	$1.06	$1.06	$1.09	$1.09	$92.36	6.30%	6.55%	5.00%	5.95%	9.78%	10.79%	11.43%
Edison International	EIX	$0.74	$0.74	$0.74	$0.78	$0.77	$0.77	$0.77	$0.81	$66.62	3.70%	4.60%	4.50%	4.27%	8.50%	9.10%	9.46%
Entergy Corporation	ETR	$1.07	$1.07	$1.07	$1.13	$1.14	$1.14	$1.14	$1.20	$98.22	7.00%	11.00%	0.50%	6.17%	5.02%	11.05%	16.19%
Evergy, Inc.	EVRG	$0.61	$0.61	$0.61	$0.64	$0.64	$0.64	$0.64	$0.67	$50.80	4.30%	2.50%	7.50%	4.77%	7.64%	10.07%	12.99%
IDACORP, Inc.	IDA	$0.79	$0.79	$0.79	$0.83	$0.82	$0.82	$0.82	$0.87	$96.32	4.40%	4.40%	4.00%	4.27%	7.55%	7.83%	7.97%
NextEra Energy, Inc.	NEE	$0.47	$0.47	$0.47	$0.47	$0.51	$0.51	$0.51	$0.51	$58.00	8.20%	7.81%	9.50%	8.50%	11.43%	12.16%	13.20%
NorthWestern Energy Group, Inc.	NWE	$0.64	$0.64	$0.64	$0.64	$0.67	$0.67	$0.67	$0.67	$49.69	5.20%	4.08%	3.50%	4.26%	9.01%	9.82%	10.83%
OGE Energy Corporation	OGE	$0.41	$0.41	$0.42	$0.42	$0.44	$0.44	$0.44	$0.44	$34.35	4.00%	negative	6.50%	5.25%	9.21%	10.55%	11.89%
Pinnacle West Capital Corporation	PNW	$0.87	$0.87	$0.88	$0.88	$0.90	$0.90	$0.92	$0.92	$73.08	4.00%	5.90%	2.50%	4.13%	7.53%	9.27%	11.16%
Portland General Electric Company	POR	$0.45	$0.48	$0.48	$0.48	$0.48	$0.50	$0.50	$0.50	$41.62	6.00%	4.60%	5.00%	5.20%	9.48%	10.12%	10.97%
Southern Company	SO	$0.68	$0.70	$0.70	$0.70	$0.72	$0.74	$0.74	$0.74	$68.91	4.00%	7.10%	6.50%	5.87%	8.32%	10.30%	11.60%
Xcel Energy Inc.	XEL	$0.52	$0.52	$0.52	$0.52	$0.55	$0.55	$0.55	$0.55	$60.09	6.00%	6.57%	6.00%	6.19%	9.80%	10.00%	10.40%
Proxy Group Mean											5.56%	5.86%	5.36%	5.58%	8.92%	10.17%	11.34%
Proxy Group Median											5.95%	5.90%	5.75%	5.50%	8.92%	10.09%	11.22%
Average of Mean and Median															8.92%	10.13%	11.28%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service
[3] Source: Bloomberg Professional Service
[4] Source: Bloomberg Professional Service
[5] Equals Col. [1] x (1 + Col. [13])
[6] Equals Col. [2] x (1 + Col. [13])
[7] Equals Col. [3] x (1 + Col. [13])
[8] Equals Col. [4] x (1 + Col. [13])
[9] Source: Bloomberg Professional, equals indicated number of trading day average as of 01/31/2024
[10] Source: Zacks
[11] Source: Yahoo! Finance
[12] Source: Value Line
[13] Equals Average (Cols. [10], [11], [12])
[14] Implied Low DCF
[15] Implied Mean DCF
[16] Implied High DCF

Quarterly Growth Discounted Cash Flow Model
180 Day Average Stock Price

Company	Ticker	[1] Dividend 1	[2] Dividend 2	[3] Dividend 3	[4] Dividend 4	[5] Expected Dividend 1	[6] Expected Dividend 2	[7] Expected Dividend 3	[8] Expected Dividend 4	[9] Average Stock Price	[10] Zacks Earnings Growth	[11] Yahoo! Earnings Growth	[12] Value Line Earnings Growth	[13] Average Earnings Growth	[14] Low ROE	[15] Mean ROE	[16] High ROE
Alliant Energy Corporation	LNT	$0.45	$0.45	$0.45	$0.48	$0.48	$0.48	$0.48	$0.51	$51.08	6.20%	6.55%	6.50%	6.42%	10.16%	10.39%	10.53%
Ameren Corporation	AEE	$0.63	$0.63	$0.63	$0.63	$0.67	$0.67	$0.67	$0.67	$78.59	5.90%	4.80%	6.50%	5.73%	8.26%	9.24%	10.04%
American Electric Power Company, Inc.	AEP	$0.83	$0.83	$0.83	$0.88	$0.87	$0.87	$0.87	$0.93	$80.50	5.10%	4.20%	6.50%	5.27%	8.70%	9.83%	11.14%
Avista Corporation	AVA	$0.46	$0.46	$0.46	$0.46	$0.49	$0.49	$0.49	$0.49	$35.95	6.20%	6.20%	6.00%	6.13%	11.66%	11.80%	11.87%
CMS Energy Corporation	CMS	$0.49	$0.49	$0.49	$0.49	$0.52	$0.52	$0.52	$0.52	$57.41	7.50%	7.70%	5.50%	6.90%	9.21%	10.67%	11.51%
DTE Energy Company	DTE	$0.95	$0.95	$0.95	$1.02	$1.00	$1.00	$1.00	$1.07	$106.22	6.00%	5.10%	4.50%	5.20%	8.43%	9.17%	10.01%
Duke Energy Corporation	DUK	$1.01	$1.01	$1.03	$1.03	$1.06	$1.06	$1.09	$1.09	$91.90	6.30%	6.55%	5.00%	5.95%	9.80%	10.82%	11.45%
Edison International	EIX	$0.74	$0.74	$0.74	$0.78	$0.77	$0.77	$0.77	$0.81	$68.01	3.70%	4.60%	4.50%	4.27%	8.40%	9.00%	9.36%
Entergy Corporation	ETR	$1.07	$1.07	$1.07	$1.13	$1.14	$1.14	$1.14	$1.20	$98.41	7.00%	11.00%	0.50%	6.17%	5.01%	11.04%	16.18%
Evergy, Inc.	EVRG	$0.61	$0.61	$0.61	$0.64	$0.64	$0.64	$0.64	$0.67	$54.31	4.30%	2.50%	7.50%	4.77%	7.30%	9.72%	12.63%
IDACORP, Inc.	IDA	$0.79	$0.79	$0.79	$0.83	$0.82	$0.82	$0.82	$0.87	$98.73	4.40%	4.40%	4.00%	4.27%	7.46%	7.74%	7.88%
NextEra Energy, Inc.	NEE	$0.47	$0.47	$0.47	$0.47	$0.51	$0.51	$0.51	$0.51	$64.77	8.20%	7.81%	9.50%	8.50%	11.05%	11.77%	12.81%
NorthWestern Energy Group, Inc.	NWE	$0.64	$0.64	$0.64	$0.64	$0.67	$0.67	$0.67	$0.67	$52.46	5.20%	4.08%	3.50%	4.26%	8.71%	9.53%	10.53%
OGE Energy Corporation	OGE	$0.41	$0.41	$0.42	$0.42	$0.44	$0.44	$0.44	$0.44	$34.91	4.00%	negative	6.50%	5.25%	9.13%	10.46%	11.80%
Pinnacle West Capital Corporation	PNW	$0.87	$0.87	$0.88	$0.88	$0.90	$0.90	$0.92	$0.92	$76.44	4.00%	5.90%	2.50%	4.13%	7.31%	9.05%	10.93%
Portland General Electric Company	POR	$0.45	$0.48	$0.48	$0.48	$0.48	$0.50	$0.50	$0.50	$44.20	6.00%	4.60%	5.00%	5.20%	9.19%	9.83%	10.68%
Southern Company	SO	$0.68	$0.70	$0.70	$0.70	$0.72	$0.74	$0.74	$0.74	$69.45	4.00%	7.10%	6.50%	5.87%	8.29%	10.26%	11.57%
Xcel Energy Inc.	XEL	$0.52	$0.52	$0.52	$0.52	$0.55	$0.55	$0.55	$0.55	$60.88	6.00%	6.57%	6.00%	6.19%	9.75%	9.95%	10.35%
Proxy Group Mean											5.56%	5.86%	5.36%	5.58%	8.77%	10.01%	11.18%
Proxy Group Median											5.95%	5.90%	5.75%	5.50%	8.71%	9.89%	11.03%
Average of Mean and Median															8.74%	9.95%	11.11%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service
[3] Source: Bloomberg Professional Service
[4] Source: Bloomberg Professional Service
[5] Equals Col. [1] x (1 + Col. [13])
[6] Equals Col. [2] x (1 + Col. [13])
[7] Equals Col. [3] x (1 + Col. [13])
[8] Equals Col. [4] x (1 + Col. [13])
[9] Source: Bloomberg Professional, equals indicated number of trading day average as of 01/31/2024
[10] Source: Zacks
[11] Source: Yahoo! Finance
[12] Source: Value Line
[13] Equals Average (Cols. [10], [11], [12])
[14] Implied Low DCF
[15] Implied Mean DCF
[16] Implied High DCF

Expected Market Return
Market DCF Based Method - Bloomberg EPS Growth

[1] Market Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.49%
[2] Market Cap. Weighted Estimate of the S&P 500 Growth Rate	13.83%
[3] Market Cap. Weighted Estimated Required Market Return	15.43%

Notes:
[1] Equals Sum of Col. [8]
[2] Equals Sum of Col. [9]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Agilent Technologies Inc	A	n/a	N/A	0.73%	N/A	N/A	N/A
American Airlines Group Inc	AAL	$9,300	0.02%	0.00%	-7.46%	0.0000%	-0.0017%
Apple Inc	AAPL	$2,851,174	7.02%	0.52%	13.00%	0.0366%	0.9127%
AbbVie Inc	ABBV	$290,254	0.71%	3.77%	9.09%	0.0270%	0.0650%
Airbnb Inc	ABNB	$62,664	0.15%	0.00%	18.20%	0.0000%	0.0281%
Abbott Laboratories	ABT	$196,435	0.48%	1.94%	8.00%	0.0094%	0.0387%
Arch Capital Group Ltd	ACGL	$30,761	0.08%	0.00%	15.00%	0.0000%	0.0114%
Accenture PLC	ACN	$242,530	0.60%	1.42%	10.00%	0.0085%	0.0597%
Adobe Inc	ADBE	$279,237	0.69%	0.00%	16.91%	0.0000%	0.1163%
Analog Devices Inc	ADI	$95,380	0.23%	1.79%	4.50%	0.0042%	0.0106%
Archer-Daniels-Midland Co	ADM	$29,645	0.07%	3.60%	-7.81%	0.0026%	-0.0057%
Automatic Data Processing Inc	ADP	$100,942	0.25%	2.28%	16.00%	0.0057%	0.0398%
Autodesk Inc	ADSK	$54,294	0.13%	0.00%	12.48%	0.0000%	0.0167%
Ameren Corp	AEE	$18,293	0.05%	3.62%	6.40%	0.0016%	0.0029%
American Electric Power Co Inc	AEP	$40,256	0.10%	4.50%	5.11%	0.0045%	0.0051%
AES Corp/The	AES	$11,169	0.03%	4.14%	10.14%	0.0011%	0.0028%
Aflac Inc	AFL	$49,287	0.12%	2.37%	6.85%	0.0029%	0.0083%
American International Group Inc	AIG	$48,799	0.12%	2.07%	10.00%	0.0025%	0.0120%
Assurant Inc	AIZ	$8,833	0.02%	1.71%	11.66%	0.0004%	0.0025%
Arthur J Gallagher & Co	AJG	$50,306	0.12%	1.03%	12.38%	0.0013%	0.0153%
Akamai Technologies Inc	AKAM	$18,587	0.05%	0.00%	7.87%	0.0000%	0.0036%
Albemarle Corp	ALB	$13,465	0.03%	1.39%	35.15%	0.0005%	0.0117%
Align Technology Inc	ALGN	$20,474	0.05%	0.00%	12.52%	0.0000%	0.0063%
Allstate Corp/The	ALL	$40,627	0.10%	2.29%	-7.00%	0.0023%	-0.0070%
Allegion plc	ALLE	$10,876	0.03%	1.45%	5.14%	0.0004%	0.0014%
Applied Materials Inc	AMAT	$136,708	0.34%	0.78%	5.50%	0.0026%	0.0185%
Amcor PLC	AMCR	$13,630	0.03%	5.30%	2.20%	0.0018%	0.0007%
Advanced Micro Devices Inc	AMD	$270,951	0.67%	0.00%	29.35%	0.0000%	0.1958%
AMETEK Inc	AME	$37,401	0.09%	0.62%	6.87%	0.0006%	0.0063%
Amgen Inc	AMGN	$168,185	0.41%	2.86%	4.23%	0.0119%	0.0175%
Ameriprise Financial Inc	AMP	n/a	N/A	1.40%	N/A	N/A	N/A
American Tower Corp	AMT	$91,205	0.22%	3.48%	11.81%	0.0078%	0.0265%
Amazon.com Inc	AMZN	$1,603,842	3.95%	0.00%	35.10%	0.0000%	1.3863%
Arista Networks Inc	ANET	$80,475	0.20%	0.00%	19.72%	0.0000%	0.0391%
ANSYS Inc	ANSS	$28,494	0.07%	0.00%	9.00%	0.0000%	0.0063%
Aon PLC	AON	$59,750	0.15%	0.82%	10.03%	0.0012%	0.0148%
A O Smith Corp	AOS	n/a	N/A	1.65%	N/A	N/A	N/A
APA Corp	APA	$9,610	0.02%	3.19%	2.00%	0.0008%	0.0005%
Air Products and Chemicals Inc	APD	$56,826	0.14%	2.77%	12.06%	0.0039%	0.0169%
Amphenol Corp	APH	$60,489	0.15%	0.87%	9.02%	0.0013%	0.0134%
Aptiv PLC	APTV	$23,005	0.06%	0.00%	11.44%	0.0000%	0.0065%
Alexandria Real Estate Equities Inc	ARE	$21,154	0.05%	4.20%	5.28%	0.0022%	0.0028%
Atmos Energy Corp	ATO	$17,186	0.04%	2.83%	7.26%	0.0012%	0.0031%
AvalonBay Communities Inc	AVB	$25,422	0.06%	3.80%	5.95%	0.0024%	0.0037%
Broadcom Inc	AVGO	$552,406	1.36%	1.78%	13.90%	0.0242%	0.1891%
Avery Dennison Corp	AVY	$16,062	0.04%	1.62%	7.00%	0.0006%	0.0028%
American Water Works Co Inc	AWK	$24,147	0.06%	2.28%	7.76%	0.0014%	0.0046%
Axon Enterprise Inc	AXON	n/a	N/A	0.00%	N/A	N/A	N/A
American Express Co	AXP	$145,135	0.36%	1.20%	14.17%	0.0043%	0.0506%
AutoZone Inc	AZO	$47,763	0.12%	0.00%	14.29%	0.0000%	0.0168%
Boeing Co/The	BA	n/a	N/A	0.00%	N/A	N/A	N/A
Bank of America Corp	BAC	$268,526	0.66%	2.82%	-7.00%	0.0187%	-0.0463%
Ball Corp	BALL	$17,483	0.04%	1.44%	9.50%	0.0006%	0.0041%
Baxter International Inc	BAX	$19,628	0.05%	3.00%	-3.00%	0.0014%	-0.0015%
Bath & Body Works Inc	BBWI	$9,639	0.02%	1.88%	6.51%	0.0004%	0.0015%
Best Buy Co Inc	BBY	$15,614	0.04%	5.08%	3.08%	0.0020%	0.0012%
Becton Dickinson & Co	BDX	$69,146	0.17%	1.59%	-2.02%	0.0027%	-0.0034%
Franklin Resources Inc	BEN	$14,022	0.03%	4.66%	-7.00%	0.0016%	-0.0024%
Brown-Forman Corp	BF/B	$16,825	0.04%	1.59%	4.85%	0.0007%	0.0020%
Bunge Global SA	BG	$14,220	0.04%	3.01%	-5.94%	0.0011%	-0.0021%
Biogen Inc	BIIB	$35,741	0.09%	0.00%	10.50%	0.0000%	0.0092%
Bio-Rad Laboratories Inc	BIO	n/a	N/A	0.00%	N/A	N/A	N/A
Bank of New York Mellon Corp/The	BK	$42,113	0.10%	3.03%	10.00%	0.0031%	0.0104%
Booking Holdings Inc	BKNG	$122,376	0.30%	0.00%	15.00%	0.0000%	0.0452%
Baker Hughes Co	BKR	$28,678	0.07%	2.81%	17.00%	0.0020%	0.0120%
Builders FirstSource Inc	BLDR	$21,429	0.05%	0.00%	-1.67%	0.0000%	-0.0009%
BlackRock Inc	BLK	$115,188	0.28%	2.63%	9.00%	0.0075%	0.0255%
Bristol-Myers Squibb Co	BMY	$99,439	0.24%	4.91%	2.78%	0.0120%	0.0068%
Broadridge Financial Solutions Inc	BR	n/a	N/A	1.57%	N/A	N/A	N/A
Berkshire Hathaway Inc	BRK/B	n/a	N/A	0.00%	N/A	N/A	N/A
Brown & Brown Inc	BRO	$22,074	0.05%	0.67%	7.91%	0.0004%	0.0043%
Boston Scientific Corp	BSX	$92,675	0.23%	0.00%	12.10%	0.0000%	0.0276%
BorgWarner Inc	BWA	$7,968	0.02%	1.30%	4.81%	0.0003%	0.0009%
Blackstone Inc	BX	$89,524	0.22%	3.02%	8.58%	0.0067%	0.0189%

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Boston Properties Inc	BXP	$10,437	0.03%	5.89%	-1.26%	0.0015%	-0.0003%
Citigroup Inc	C	$106,897	0.26%	3.77%	21.67%	0.0099%	0.0570%
Conagra Brands Inc	CAG	$13,934	0.03%	4.80%	2.08%	0.0016%	0.0007%
Cardinal Health Inc	CAH	$26,912	0.07%	1.83%	13.66%	0.0012%	0.0091%
Carrier Global Corp	CARR	$49,111	0.12%	1.39%	10.94%	0.0017%	0.0132%
Caterpillar Inc	CAT	$152,883	0.38%	1.73%	20.00%	0.0065%	0.0753%
Chubb Ltd	CB	$99,291	0.24%	1.40%	6.00%	0.0034%	0.0147%
Cboe Global Markets Inc	CBOE	$19,406	0.05%	1.20%	12.81%	0.0006%	0.0061%
CBRE Group Inc	CBRE	n/a	N/A	0.00%	N/A	N/A	N/A
Crown Castle Inc	CCI	$46,981	0.12%	5.78%	7.00%	0.0067%	0.0081%
Carnival Corp	CCL	n/a	N/A	0.00%	N/A	N/A	N/A
Dayforce Inc	CDAY	n/a	N/A	0.00%	N/A	N/A	N/A
Cadence Design Systems Inc	CDNS	$78,479	0.19%	0.00%	17.03%	0.0000%	0.0329%
CDW Corp/DE	CDW	$30,371	0.07%	1.09%	13.10%	0.0008%	0.0098%
Celanese Corp	CE	$15,924	0.04%	1.91%	2.16%	0.0008%	0.0008%
Constellation Energy Corp	CEG	$38,965	0.10%	0.92%	27.95%	0.0009%	0.0268%
CF Industries Holdings Inc	CF	$14,427	0.04%	2.65%	46.00%	0.0009%	0.0163%
Citizens Financial Group Inc	CFG	$15,252	0.04%	5.14%	-6.96%	0.0019%	-0.0026%
Church & Dwight Co Inc	CHD	$24,601	0.06%	1.09%	6.28%	0.0007%	0.0038%
CH Robinson Worldwide Inc	CHRW	$9,809	0.02%	2.90%	-10.00%	0.0007%	-0.0024%
Charter Communications Inc	CHTR	$54,835	0.14%	0.00%	12.44%	0.0000%	0.0168%
Cigna Group/The	CI	$88,064	0.22%	1.63%	9.80%	0.0035%	0.0213%
Cincinnati Financial Corp	CINF	$17,385	0.04%	2.92%	15.15%	0.0013%	0.0065%
Colgate-Palmolive Co	CL	$69,328	0.17%	2.28%	8.18%	0.0039%	0.0140%
Clorox Co/The	CLX	$18,020	0.04%	3.30%	11.90%	0.0015%	0.0053%
Comerica Inc	CMA	$6,934	0.02%	5.40%	31.00%	0.0009%	0.0053%
Comcast Corp	CMCSA	$184,411	0.45%	2.66%	9.65%	0.0121%	0.0438%
CME Group Inc	CME	$74,100	0.18%	2.14%	8.54%	0.0039%	0.0156%
Chipotle Mexican Grill Inc	CMG	$66,109	0.16%	0.00%	24.78%	0.0000%	0.0403%
Cummins Inc	CMI	$33,920	0.08%	2.81%	7.01%	0.0023%	0.0059%
CMS Energy Corp	CMS	$16,677	0.04%	3.41%	7.75%	0.0014%	0.0032%
Centene Corp	CNC	$40,231	0.10%	0.00%	9.26%	0.0000%	0.0092%
CenterPoint Energy Inc	CNP	$17,586	0.04%	2.86%	8.02%	0.0012%	0.0035%
Capital One Financial Corp	COF	$51,476	0.13%	1.77%	50.24%	0.0022%	0.0637%
Cooper Cos Inc/The	COO	$18,475	0.05%	0.00%	9.41%	0.0000%	0.0043%
ConocoPhillips	COP	$132,835	0.33%	0.52%	12.00%	0.0017%	0.0393%
Cencora Inc	COR	$46,415	0.11%	0.88%	8.66%	0.0010%	0.0099%
Costco Wholesale Corp	COST	$308,338	0.76%	0.59%	7.64%	0.0045%	0.0580%
Campbell Soup Co	CPB	$13,304	0.03%	3.32%	2.81%	0.0011%	0.0009%
Copart Inc	CPRT	n/a	N/A	0.00%	N/A	N/A	N/A
Camden Property Trust	CPT	$10,019	0.02%	4.26%	5.67%	0.0011%	0.0014%
Charles River Laboratories Internatio	CRL	$11,095	0.03%	0.00%	14.00%	0.0000%	0.0038%
Salesforce Inc	CRM	$272,095	0.67%	0.00%	22.50%	0.0000%	0.1508%
Cisco Systems Inc	CSCO	$203,905	0.50%	3.11%	10.00%	0.0156%	0.0502%
CoStar Group Inc	CSGP	$34,090	0.08%	0.00%	20.00%	0.0000%	0.0168%
CSX Corp	CSX	$70,548	0.17%	1.23%	6.75%	0.0021%	0.0117%
Cintas Corp	CTAS	$61,286	0.15%	0.89%	11.35%	0.0013%	0.0171%
Catalent Inc	CTLT	$9,328	0.02%	0.00%	26.24%	0.0000%	0.0060%
Coterra Energy Inc	CTRA	$18,715	0.05%	3.22%	55.04%	0.0015%	0.0254%
Cognizant Technology Solutions Cor	CTSH	$38,669	0.10%	1.50%	12.00%	0.0014%	0.0114%
Corteva Inc	CTVA	$32,058	0.08%	1.41%	16.42%	0.0011%	0.0130%
CVS Health Corp	CVS	$95,707	0.24%	3.58%	6.24%	0.0084%	0.0147%
Chevron Corp	CVX	$278,311	0.69%	4.10%	7.27%	0.0281%	0.0498%
Caesars Entertainment Inc	CZR	$9,463	0.02%	0.00%	127.12%	0.0000%	0.0296%
Dominion Energy Inc	D	$38,257	0.09%	5.84%	6.90%	0.0055%	0.0065%
Delta Air Lines Inc	DAL	$25,185	0.06%	1.02%	8.37%	0.0006%	0.0052%
DuPont de Nemours Inc	DD	$26,577	0.07%	2.33%	10.20%	0.0015%	0.0067%
Deere & Co	DE	$110,198	0.27%	1.49%	3.96%	0.0041%	0.0107%
Discover Financial Services	DFS	$26,386	0.06%	2.65%	17.16%	0.0017%	0.0111%
Dollar General Corp	DG	$28,989	0.07%	1.79%	-5.94%	0.0013%	-0.0042%
Quest Diagnostics Inc	DGX	$14,440	0.04%	2.21%	-1.18%	0.0008%	-0.0004%
DR Horton Inc	DHI	$47,420	0.12%	0.84%	4.49%	0.0010%	0.0052%
Danaher Corp	DHR	$177,341	0.44%	0.40%	5.83%	0.0017%	0.0255%
Walt Disney Co/The	DIS	$175,802	0.43%	0.62%	18.88%	0.0027%	0.0817%
Digital Realty Trust Inc	DLR	$42,538	0.10%	3.47%	6.80%	0.0036%	0.0071%
Dollar Tree Inc	DLTR	$28,458	0.07%	0.00%	7.77%	0.0000%	0.0054%
Dover Corp	DOV	$20,953	0.05%	1.36%	10.00%	0.0007%	0.0052%
Dow Inc	DOW	$37,643	0.09%	5.22%	23.26%	0.0048%	0.0216%
Domino's Pizza Inc	DPZ	$14,867	0.04%	1.14%	12.71%	0.0004%	0.0047%
Darden Restaurants Inc	DRI	$19,414	0.05%	3.22%	3.78%	0.0015%	0.0018%
DTE Energy Co	DTE	$21,728	0.05%	3.87%	7.00%	0.0021%	0.0037%
Duke Energy Corp	DUK	$73,885	0.18%	4.28%	6.34%	0.0078%	0.0115%
DaVita Inc	DVA	$9,875	0.02%	0.00%	19.69%	0.0000%	0.0048%
Devon Energy Corp	DVN	$26,922	0.07%	7.33%	21.68%	0.0049%	0.0144%
Dexcom Inc	DXCM	$46,886	0.12%	0.00%	26.89%	0.0000%	0.0310%
Electronic Arts Inc	EA	$37,004	0.09%	0.55%	11.07%	0.0005%	0.0101%
eBay Inc	EBAY	$21,315	0.05%	2.43%	0.32%	0.0013%	0.0002%
Ecolab Inc	ECL	$56,520	0.14%	1.15%	14.33%	0.0016%	0.0199%
Consolidated Edison Inc	ED	$31,354	0.08%	3.65%	6.00%	0.0028%	0.0046%
Equifax Inc	EFX	$30,107	0.07%	0.64%	13.64%	0.0005%	0.0101%
Everest Group Ltd	EG	$16,704	0.04%	1.82%	33.50%	0.0007%	0.0138%
Edison International	EIX	$25,883	0.06%	4.62%	6.00%	0.0029%	0.0038%
Estee Lauder Cos Inc/The	EL	$30,662	0.08%	2.00%	10.88%	0.0015%	0.0082%
Elevance Health Inc	ELV	$115,938	0.29%	1.32%	10.83%	0.0038%	0.0309%
Eastman Chemical Co	EMN	$9,906	0.02%	3.88%	5.02%	0.0009%	0.0012%
Emerson Electric Co	EMR	$52,295	0.13%	2.29%	12.01%	0.0029%	0.0155%
Enphase Energy Inc	ENPH	$14,219	0.04%	0.00%	28.57%	0.0000%	0.0100%
EOG Resources Inc	EOG	$66,357	0.16%	3.20%	17.83%	0.0052%	0.0291%

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
EPAM Systems Inc	EPAM	$16,047	0.04%	0.00%	4.87%	0.0000%	0.0019%
Equinix Inc	EQIX	$77,901	0.19%	2.05%	14.63%	0.0039%	0.0281%
Equity Residential	EQR	$22,830	0.06%	4.40%	4.75%	0.0025%	0.0027%
EQT Corp	EQT	$14,561	0.04%	1.78%	21.41%	0.0006%	0.0077%
Eversource Energy	ES	$18,927	0.05%	5.27%	5.21%	0.0025%	0.0024%
Essex Property Trust Inc	ESS	$14,972	0.04%	3.96%	5.71%	0.0015%	0.0021%
Eaton Corp PLC	ETN	$98,260	0.24%	1.40%	15.00%	0.0034%	0.0363%
Entergy Corp	ETR	$21,095	0.05%	4.53%	6.51%	0.0024%	0.0034%
Etsy Inc	ETSY	$7,970	0.02%	0.00%	8.47%	0.0000%	0.0017%
Evergy Inc	EVRG	$11,656	0.03%	5.06%	4.35%	0.0015%	0.0012%
Edwards Lifesciences Corp	EW	$47,592	0.12%	0.00%	8.75%	0.0000%	0.0103%
Exelon Corp	EXC	$34,612	0.09%	4.14%	4.69%	0.0035%	0.0040%
Expeditors International of Washingto	EXPD	$18,367	0.05%	1.09%	-16.00%	0.0005%	-0.0072%
Expedia Group Inc	EXPE	$19,776	0.05%	0.00%	17.50%	0.0000%	0.0085%
Extra Space Storage Inc	EXR	$30,517	0.08%	4.49%	1.20%	0.0034%	0.0009%
Ford Motor Co	F	$46,084	0.11%	5.12%	-2.52%	0.0058%	-0.0029%
Diamondback Energy Inc	FANG	$27,517	0.07%	8.77%	8.47%	0.0059%	0.0057%
Fastenal Co	FAST	n/a	N/A	2.29%	N/A	N/A	N/A
Freeport-McMoRan Inc	FCX	$56,915	0.14%	1.51%	-15.66%	0.0021%	-0.0219%
FactSet Research Systems Inc	FDS	$18,126	0.04%	0.82%	10.60%	0.0004%	0.0047%
FedEx Corp	FDX	$60,297	0.15%	2.09%	13.50%	0.0031%	0.0200%
FirstEnergy Corp	FE	$21,048	0.05%	4.47%	-0.33%	0.0023%	-0.0002%
F5 Inc	FFIV	$10,801	0.03%	0.00%	7.09%	0.0000%	0.0019%
Fiserv Inc	FI	$85,148	0.21%	0.00%	15.20%	0.0000%	0.0319%
Fair Isaac Corp	FICO	$29,793	0.07%	0.00%	22.00%	0.0000%	0.0161%
Fidelity National Information Services	FIS	$36,888	0.09%	3.34%	11.42%	0.0030%	0.0104%
Fifth Third Bancorp	FITB	$23,322	0.06%	4.09%	25.00%	0.0023%	0.0144%
FleetCor Technologies Inc	FLT	$20,934	0.05%	0.00%	12.79%	0.0000%	0.0066%
FMC Corp	FMC	$7,011	0.02%	4.13%	-4.00%	0.0007%	-0.0007%
Fox Corp	FOX	$7,070	0.02%	1.73%	12.00%	0.0003%	0.0021%
Fox Corp	FOXA	$7,985	0.02%	1.61%	12.00%	0.0003%	0.0024%
Federal Realty Investment Trust	FRT	$8,303	0.02%	4.29%	4.42%	0.0009%	0.0009%
First Solar Inc	FSLR	$15,631	0.04%	0.00%	43.22%	0.0000%	0.0166%
Fortinet Inc	FTNT	$49,523	0.12%	0.00%	14.37%	0.0000%	0.0175%
Fortive Corp	FTV	$27,475	0.07%	0.41%	9.29%	0.0003%	0.0063%
General Dynamics Corp	GD	$72,315	0.18%	1.99%	11.30%	0.0035%	0.0201%
General Electric Co	GE	$144,124	0.35%	0.24%	7.00%	0.0009%	0.0248%
GE HealthCare Technologies Inc	GEHC	$33,397	0.08%	0.16%	12.70%	0.0001%	0.0104%
Gen Digital Inc	GEN	$15,044	0.04%	2.13%	12.98%	0.0008%	0.0048%
Gilead Sciences Inc	GILD	$97,515	0.24%	3.83%	3.06%	0.0092%	0.0074%
General Mills Inc	GIS	$36,862	0.09%	3.64%	8.00%	0.0033%	0.0073%
Globe Life Inc	GL	n/a	N/A	0.73%	N/A	N/A	N/A
Corning Inc	GLW	$27,720	0.07%	3.45%	9.34%	0.0024%	0.0064%
General Motors Co	GM	$44,792	0.11%	1.24%	15.71%	0.0014%	0.0173%
Generac Holdings Inc	GNRC	$6,983	0.02%	0.00%	5.00%	0.0000%	0.0009%
Alphabet Inc	GOOG	$804,148	1.98%	0.00%	10.05%	0.0000%	0.1991%
Alphabet Inc	GOOGL	$825,609	2.03%	0.00%	10.05%	0.0000%	0.2044%
Genuine Parts Co	GPC	$19,660	0.05%	2.71%	9.26%	0.0013%	0.0045%
Global Payments Inc	GPN	$34,692	0.09%	0.75%	13.05%	0.0006%	0.0111%
Garmin Ltd	GRMN	$22,862	0.06%	2.44%	5.60%	0.0014%	0.0032%
Goldman Sachs Group Inc/The	GS	$125,230	0.31%	2.86%	8.36%	0.0088%	0.0258%
WW Grainger Inc	GWW	n/a	N/A	0.83%	N/A	N/A	N/A
Halliburton Co	HAL	$31,909	0.08%	1.91%	16.34%	0.0015%	0.0128%
Hasbro Inc	HAS	$6,792	0.02%	5.72%	-3.49%	0.0010%	-0.0006%
Huntington Bancshares Inc/OH	HBAN	$18,433	0.05%	4.87%	-5.65%	0.0022%	-0.0026%
HCA Healthcare Inc	HCA	$81,610	0.20%	0.87%	7.72%	0.0017%	0.0155%
Home Depot Inc/The	HD	$351,288	0.87%	2.37%	1.82%	0.0205%	0.0157%
Hess Corp	HES	$43,164	0.11%	1.25%	13.50%	0.0013%	0.0143%
Hartford Financial Services Group Inc	HIG	$26,155	0.06%	2.16%	7.00%	0.0014%	0.0045%
Huntington Ingalls Industries Inc	HII	$10,285	0.03%	2.01%	40.00%	0.0005%	0.0101%
Hilton Worldwide Holdings Inc	HLT	$48,970	0.12%	0.31%	17.14%	0.0004%	0.0207%
Hologic Inc	HOLX	$17,473	0.04%	0.00%	8.86%	0.0000%	0.0038%
Honeywell International Inc	HON	$133,340	0.33%	2.14%	7.87%	0.0070%	0.0258%
Hewlett Packard Enterprise Co	HPE	$19,877	0.05%	3.40%	2.64%	0.0017%	0.0013%
HP Inc	HPQ	$28,449	0.07%	3.84%	3.00%	0.0027%	0.0021%
Hormel Foods Corp	HRL	$16,608	0.04%	3.72%	1.08%	0.0015%	0.0004%
Henry Schein Inc	HSIC	$9,773	0.02%	0.00%	3.44%	0.0000%	0.0008%
Host Hotels & Resorts Inc	HST	n/a	N/A	4.16%	N/A	N/A	N/A
Hershey Co/The	HSY	$29,009	0.07%	2.46%	9.00%	0.0018%	0.0064%
Hubbell Inc	HUBB	$17,994	0.04%	1.45%	18.00%	0.0006%	0.0080%
Humana Inc	HUM	$46,208	0.11%	0.94%	-3.07%	0.0011%	-0.0035%
Howmet Aerospace Inc	HWM	$23,165	0.06%	0.36%	20.41%	0.0002%	0.0116%
International Business Machines Corp	IBM	$167,703	0.41%	3.62%	5.14%	0.0149%	0.0212%
Intercontinental Exchange Inc	ICE	$72,879	0.18%	1.32%	9.64%	0.0024%	0.0173%
IDEXX Laboratories Inc	IDXX	$42,778	0.11%	0.00%	16.36%	0.0000%	0.0172%
IDEX Corp	IEX	$15,995	0.04%	1.21%	11.00%	0.0005%	0.0043%
International Flavors & Fragrances In	IFF	$20,596	0.05%	4.02%	5.67%	0.0020%	0.0029%
Illumina Inc	ILMN	$22,710	0.06%	0.00%	-9.88%	0.0000%	-0.0055%
Incyte Corp	INCY	$13,171	0.03%	0.00%	37.00%	0.0000%	0.0120%
Intel Corp	INTC	$182,142	0.45%	1.16%	31.13%	0.0052%	0.1396%
Intuit Inc	INTU	$176,732	0.44%	0.57%	18.96%	0.0025%	0.0825%
Invitation Homes Inc	INVH	$20,152	0.05%	3.40%	2.83%	0.0017%	0.0014%
International Paper Co	IP	$12,398	0.03%	5.16%	-2.00%	0.0016%	-0.0006%
Interpublic Group of Cos Inc/The	IPG	$12,635	0.03%	3.76%	6.29%	0.0012%	0.0020%
IQVIA Holdings Inc	IQV	$38,002	0.09%	0.00%	9.67%	0.0000%	0.0090%
Ingersoll Rand Inc	IR	$32,327	0.08%	0.10%	14.00%	0.0001%	0.0111%
Iron Mountain Inc	IRM	$19,715	0.05%	3.85%	4.00%	0.0019%	0.0019%
Intuitive Surgical Inc	ISRG	$133,257	0.33%	0.00%	12.00%	0.0000%	0.0394%

		[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Market Capitalization Excluding No Growth Rate	Weight in Index	Dividend Yield	Long-Term Growth Est.	Weighted Dividend Yield	Weighted Long-Term Growth Rate
Gartner Inc	IT	$35,657	0.09%	0.00%	8.24%	0.0000%	0.0072%
Illinois Tool Works Inc	ITW	$78,501	0.19%	2.15%	3.86%	0.0041%	0.0075%
Invesco Ltd	IVZ	$7,116	0.02%	5.05%	4.00%	0.0009%	0.0007%
Jacobs Solutions Inc	J	$17,024	0.04%	0.86%	12.31%	0.0004%	0.0052%
JB Hunt Transport Services Inc	JBHT	$20,730	0.05%	0.86%	15.00%	0.0004%	0.0077%
Jabil Inc	JBL	$15,980	0.04%	0.26%	12.00%	0.0001%	0.0047%
Johnson Controls International plc	JCI	$35,907	0.09%	2.81%	9.77%	0.0025%	0.0086%
Jack Henry & Associates Inc	JKHY	$12,077	0.03%	1.25%	7.06%	0.0004%	0.0021%
Johnson & Johnson	JNJ	$382,517	0.94%	3.00%	3.76%	0.0282%	0.0354%
Juniper Networks Inc	JNPR	$11,785	0.03%	2.38%	7.96%	0.0007%	0.0023%
JPMorgan Chase & Co	JPM	$504,076	1.24%	2.41%	2.00%	0.0299%	0.0248%
Kellanova	K	$18,756	0.05%	4.09%	-2.42%	0.0019%	-0.0011%
Keurig Dr Pepper Inc	KDP	$43,964	0.11%	2.74%	6.81%	0.0030%	0.0074%
KeyCorp	KEY	$13,608	0.03%	5.64%	-1.67%	0.0019%	-0.0006%
Keysight Technologies Inc	KEYS	$26,827	0.07%	0.00%	2.61%	0.0000%	0.0017%
Kraft Heinz Co/The	KHC	$45,541	0.11%	4.31%	4.46%	0.0048%	0.0050%
Kimco Realty Corp	KIM	$13,569	0.03%	4.75%	4.75%	0.0016%	0.0016%
KLA Corp	KLAC	$80,334	0.20%	0.98%	9.06%	0.0019%	0.0179%
Kimberly-Clark Corp	KMB	$40,881	0.10%	4.03%	4.42%	0.0041%	0.0044%
Kinder Morgan Inc	KMI	$37,609	0.09%	6.68%	3.00%	0.0062%	0.0028%
CarMax Inc	KMX	$11,241	0.03%	0.00%	29.90%	0.0000%	0.0083%
Coca-Cola Co/The	KO	$257,200	0.63%	3.09%	6.58%	0.0196%	0.0417%
Kroger Co/The	KR	$33,194	0.08%	2.51%	4.21%	0.0021%	0.0034%
Kenvue Inc	KVUE	n/a	N/A	3.85%	N/A	N/A	N/A
Loews Corp	L	n/a	N/A	0.34%	N/A	N/A	N/A
Leidos Holdings Inc	LDOS	$15,190	0.04%	1.38%	8.12%	0.0005%	0.0030%
Lennar Corp	LEN	$37,037	0.09%	1.33%	9.02%	0.0012%	0.0082%
Laboratory Corp of America Holdings	LH	$18,873	0.05%	1.30%	-7.29%	0.0006%	-0.0034%
L3Harris Technologies Inc	LHX	$39,504	0.10%	2.19%	5.53%	0.0021%	0.0054%
Linde PLC	LIN	$196,298	0.48%	1.26%	14.00%	0.0061%	0.0677%
LKQ Corp	LKQ	$12,489	0.03%	2.57%	11.50%	0.0008%	0.0035%
Eli Lilly & Co	LLY	$612,882	1.51%	0.81%	24.60%	0.0122%	0.3713%
Lockheed Martin Corp	LMT	$103,764	0.26%	2.93%	5.39%	0.0075%	0.0138%
Alliant Energy Corp	LNT	$12,297	0.03%	3.95%	6.16%	0.0012%	0.0019%
Lowe's Cos Inc	LOW	$122,407	0.30%	2.07%	4.43%	0.0062%	0.0134%
Lam Research Corp	LRCX	$108,182	0.27%	0.97%	11.37%	0.0026%	0.0303%
Lululemon Athletica Inc	LULU	$54,946	0.14%	0.00%	17.00%	0.0000%	0.0230%
Southwest Airlines Co	LUV	$17,818	0.04%	2.41%	15.74%	0.0011%	0.0069%
Las Vegas Sands Corp	LVS	n/a	N/A	1.64%	N/A	N/A	N/A
Lamb Weston Holdings Inc	LW	$14,789	0.04%	1.41%	15.46%	0.0005%	0.0056%
LyondellBasell Industries NV	LYB	$30,529	0.08%	5.31%	8.00%	0.0040%	0.0060%
Live Nation Entertainment Inc	LYV	n/a	N/A	0.00%	N/A	N/A	N/A
Mastercard Inc	MA	$417,981	1.03%	0.59%	16.64%	0.0060%	0.1713%
Mid-America Apartment Communities	MAA	$14,747	0.04%	4.65%	1.86%	0.0017%	0.0007%
Marriott International Inc/MD	MAR	$70,407	0.17%	0.87%	17.45%	0.0015%	0.0303%
Masco Corp	MAS	$15,107	0.04%	1.69%	6.17%	0.0006%	0.0023%
McDonald's Corp	MCD	$212,322	0.52%	2.28%	9.53%	0.0119%	0.0498%
Microchip Technology Inc	MCHP	$46,086	0.11%	2.06%	-1.85%	0.0023%	-0.0021%
McKesson Corp	MCK	$66,516	0.16%	0.50%	10.04%	0.0008%	0.0164%
Moody's Corp	MCO	$71,743	0.18%	0.79%	13.59%	0.0014%	0.0240%
Mondelez International Inc	MDLZ	$102,435	0.25%	2.26%	8.83%	0.0057%	0.0223%
Medtronic PLC	MDT	$116,398	0.29%	3.15%	4.33%	0.0090%	0.0124%
MetLife Inc	MET	$51,310	0.13%	3.00%	9.84%	0.0038%	0.0124%
Meta Platforms Inc	META	$865,957	2.13%	0.00%	20.79%	0.0000%	0.4433%
MGM Resorts International	MGM	n/a	N/A	0.00%	N/A	N/A	N/A
Mohawk Industries Inc	MHK	$6,639	0.02%	0.00%	-2.33%	0.0000%	-0.0004%
McCormick & Co Inc/MD	MKC	$17,138	0.04%	2.46%	5.40%	0.0010%	0.0023%
MarketAxess Holdings Inc	MKTX	n/a	N/A	1.31%	N/A	N/A	N/A
Martin Marietta Materials Inc	MLM	$31,424	0.08%	0.58%	20.66%	0.0005%	0.0160%
Marsh & McLennan Cos Inc	MMC	$95,577	0.24%	1.47%	8.27%	0.0034%	0.0195%
3M Co	MMM	$52,111	0.13%	6.36%	5.50%	0.0082%	0.0071%
Monster Beverage Corp	MNST	$57,245	0.14%	0.00%	15.46%	0.0000%	0.0218%
Altria Group Inc	MO	$70,958	0.17%	9.77%	4.50%	0.0171%	0.0079%
Molina Healthcare Inc	MOH	$20,780	0.05%	0.00%	11.24%	0.0000%	0.0058%
Mosaic Co/The	MOS	$10,037	0.02%	2.74%	24.50%	0.0007%	0.0061%
Marathon Petroleum Corp	MPC	$62,878	0.15%	1.99%	-11.89%	0.0031%	-0.0184%
Monolithic Power Systems Inc	MPWR	$28,878	0.07%	0.66%	8.00%	0.0005%	0.0057%
Merck & Co Inc	MRK	$306,059	0.75%	2.55%	17.33%	0.0192%	0.1306%
Moderna Inc	MRNA	$38,529	0.09%	0.00%	-29.33%	0.0000%	-0.0278%
Marathon Oil Corp	MRO	$13,373	0.03%	1.93%	8.00%	0.0006%	0.0026%
Morgan Stanley	MS	$143,188	0.35%	3.90%	5.28%	0.0137%	0.0186%
MSCI Inc	MSCI	$47,351	0.12%	1.07%	12.12%	0.0012%	0.0141%
Microsoft Corp	MSFT	$2,954,193	7.27%	0.75%	16.62%	0.0549%	1.2091%
Motorola Solutions Inc	MSI	$53,027	0.13%	1.23%	10.82%	0.0016%	0.0141%
M&T Bank Corp	MTB	$22,945	0.06%	3.77%	8.08%	0.0021%	0.0046%
Match Group Inc	MTCH	$10,432	0.03%	0.00%	28.33%	0.0000%	0.0073%
Mettler-Toledo International Inc	MTD	$25,960	0.06%	0.00%	5.96%	0.0000%	0.0038%
Micron Technology Inc	MU	$94,660	0.23%	0.54%	-7.00%	0.0013%	-0.0163%
Norwegian Cruise Line Holdings Ltd	NCLH	n/a	N/A	0.00%	N/A	N/A	N/A
Nasdaq Inc	NDAQ	$33,331	0.08%	1.52%	9.08%	0.0013%	0.0075%
Nordson Corp	NDSN	$14,352	0.04%	1.08%	45.00%	0.0004%	0.0159%
NextEra Energy Inc	NEE	$118,650	0.29%	3.19%	8.10%	0.0093%	0.0237%
Newmont Corp	NEM	$39,772	0.10%	4.64%	6.21%	0.0045%	0.0061%
Netflix Inc	NFLX	$244,124	0.60%	0.00%	31.81%	0.0000%	0.1912%
NiSource Inc	NI	$10,736	0.03%	4.08%	7.65%	0.0011%	0.0020%
NIKE Inc	NKE	$123,585	0.30%	1.46%	14.65%	0.0044%	0.0446%
Northrop Grumman Corp	NOC	$67,030	0.17%	1.67%	16.03%	0.0028%	0.0265%
ServiceNow Inc	NOW	$156,907	0.39%	0.00%	30.00%	0.0000%	0.1159%

		[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Market Capitalization Excluding No Growth Rate	Weight in Index	Dividend Yield	Long-Term Growth Est.	Weighted Dividend Yield	Weighted Long-Term Growth Rate
NRG Energy Inc	NRG	$11,975	0.03%	3.07%	8.88%	0.0009%	0.0026%
Norfolk Southern Corp	NSC	$53,089	0.13%	2.30%	0.61%	0.0030%	0.0008%
NetApp Inc	NTAP	$17,966	0.04%	2.29%	6.00%	0.0010%	0.0027%
Northern Trust Corp	NTRS	$16,336	0.04%	3.77%	2.57%	0.0015%	0.0010%
Nucor Corp	NUE	$45,955	0.11%	1.16%	-10.80%	0.0013%	-0.0122%
NVIDIA Corp	NVDA	$1,519,717	3.74%	0.03%	43.97%	0.0010%	1.6454%
NVR Inc	NVR	$22,606	0.06%	0.00%	4.41%	0.0000%	0.0025%
News Corp	NWS	n/a	N/A	0.78%	N/A	N/A	N/A
News Corp	NWSA	n/a	N/A	0.81%	N/A	N/A	N/A
NXP Semiconductors NV	NXPI	$54,277	0.13%	1.93%	34.00%	0.0026%	0.0454%
Realty Income Corp	O	$45,241	0.11%	5.66%	1.39%	0.0063%	0.0015%
Old Dominion Freight Line Inc	ODFL	$42,666	0.11%	0.53%	9.31%	0.0006%	0.0098%
ONEOK Inc	OKE	$39,759	0.10%	5.80%	7.65%	0.0057%	0.0075%
Omnicom Group Inc	OMC	$17,889	0.04%	3.10%	4.83%	0.0014%	0.0021%
ON Semiconductor Corp	ON	$30,636	0.08%	0.00%	1.60%	0.0000%	0.0012%
Oracle Corp	ORCL	$307,055	0.76%	1.43%	15.00%	0.0108%	0.1134%
O'Reilly Automotive Inc	ORLY	$60,526	0.15%	0.00%	11.80%	0.0000%	0.0176%
Otis Worldwide Corp	OTIS	$36,195	0.09%	1.54%	9.00%	0.0014%	0.0080%
Occidental Petroleum Corp	OXY	n/a	N/A	1.25%	N/A	N/A	N/A
Palo Alto Networks Inc	PANW	$106,732	0.26%	0.00%	30.00%	0.0000%	0.0788%
Paramount Global	PARA	$8,910	0.02%	1.37%	-21.36%	0.0003%	-0.0047%
Paycom Software Inc	PAYC	$11,458	0.03%	0.79%	15.19%	0.0002%	0.0043%
Paychex Inc	PAYX	$43,801	0.11%	2.92%	7.00%	0.0032%	0.0076%
PACCAR Inc	PCAR	$52,534	0.13%	1.08%	12.00%	0.0014%	0.0155%
PG&E Corp	PCG	$35,992	0.09%	0.24%	6.26%	0.0002%	0.0055%
Healthpeak Properties Inc	PEAK	$10,121	0.02%	6.49%	1.21%	0.0016%	0.0003%
Public Service Enterprise Group Inc	PEG	$28,943	0.07%	3.93%	5.47%	0.0028%	0.0039%
PepsiCo Inc	PEP	$231,706	0.57%	3.00%	8.62%	0.0171%	0.0492%
Pfizer Inc	PFE	$152,905	0.38%	6.20%	33.35%	0.0234%	0.1256%
Principal Financial Group Inc	PFG	$18,858	0.05%	3.39%	8.77%	0.0016%	0.0041%
Procter & Gamble Co/The	PG	$369,754	0.91%	2.39%	7.56%	0.0218%	0.0688%
Progressive Corp/The	PGR	$104,330	0.26%	0.22%	29.97%	0.0006%	0.0770%
Parker-Hannifin Corp	PH	$59,677	0.15%	1.27%	15.28%	0.0019%	0.0225%
PulteGroup Inc	PHM	$22,543	0.06%	0.77%	5.41%	0.0004%	0.0030%
Packaging Corp of America	PKG	$14,867	0.04%	3.01%	3.00%	0.0011%	0.0011%
Prologis Inc	PLD	$117,058	0.29%	2.75%	8.60%	0.0079%	0.0248%
Philip Morris International Inc	PM	$141,036	0.35%	5.72%	6.49%	0.0199%	0.0225%
PNC Financial Services Group Inc/Th	PNC	$60,182	0.15%	4.10%	14.67%	0.0061%	0.0217%
Pentair PLC	PNR	$12,095	0.03%	1.26%	7.53%	0.0004%	0.0022%
Pinnacle West Capital Corp	PNW	$7,807	0.02%	5.11%	6.98%	0.0010%	0.0013%
Insulet Corp	PODD	$13,328	0.03%	0.00%	39.34%	0.0000%	0.0129%
Pool Corp	POOL	$14,360	0.04%	1.19%	-0.25%	0.0004%	-0.0001%
PPG Industries Inc	PPG	$33,257	0.08%	1.84%	11.71%	0.0015%	0.0096%
PPL Corp	PPL	$19,313	0.05%	3.66%	8.00%	0.0017%	0.0038%
Prudential Financial Inc	PRU	$37,880	0.09%	4.77%	10.55%	0.0044%	0.0098%
Public Storage	PSA	$49,793	0.12%	4.24%	3.77%	0.0052%	0.0046%
Phillips 66	PSX	$63,490	0.16%	2.91%	-7.56%	0.0046%	-0.0118%
PTC Inc	PTC	$21,576	0.05%	0.00%	19.53%	0.0000%	0.0104%
Quanta Services Inc	PWR	$28,193	0.07%	0.19%	8.00%	0.0001%	0.0056%
Pioneer Natural Resources Co	PXD	$53,694	0.13%	5.57%	2.00%	0.0074%	0.0026%
PayPal Holdings Inc	PYPL	$66,144	0.16%	0.00%	6.26%	0.0000%	0.0102%
QUALCOMM Inc	QCOM	$165,737	0.41%	2.15%	10.81%	0.0088%	0.0441%
Qorvo Inc	QRVO	$9,709	0.02%	0.00%	18.15%	0.0000%	0.0043%
Royal Caribbean Cruises Ltd	RCL	n/a	N/A	0.00%	N/A	N/A	N/A
Regency Centers Corp	REG	$11,567	0.03%	4.28%	3.46%	0.0012%	0.0010%
Regeneron Pharmaceuticals Inc	REGN	$100,999	0.25%	0.00%	5.33%	0.0000%	0.0133%
Regions Financial Corp	RF	$17,364	0.04%	5.14%	1.41%	0.0022%	0.0006%
Robert Half Inc	RHI	n/a	N/A	2.41%	N/A	N/A	N/A
Raymond James Financial Inc	RJF	$22,995	0.06%	1.63%	13.15%	0.0009%	0.0074%
Ralph Lauren Corp	RL	$5,711	0.01%	2.09%	10.25%	0.0003%	0.0014%
ResMed Inc	RMD	$27,976	0.07%	1.01%	8.67%	0.0007%	0.0060%
Rockwell Automation Inc	ROK	$29,024	0.07%	1.97%	11.06%	0.0014%	0.0079%
Rollins Inc	ROL	$20,964	0.05%	1.39%	14.86%	0.0007%	0.0077%
Roper Technologies Inc	ROP	$57,363	0.14%	0.56%	8.00%	0.0008%	0.0113%
Ross Stores Inc	ROST	$47,228	0.12%	0.96%	10.00%	0.0011%	0.0116%
Republic Services Inc	RSG	$53,841	0.13%	1.25%	10.11%	0.0017%	0.0134%
RTX Corp	RTX	$131,022	0.32%	2.59%	10.14%	0.0084%	0.0327%
Revvity Inc	RVTY	$13,227	0.03%	0.26%	-7.32%	0.0001%	-0.0024%
SBA Communications Corp	SBAC	$24,152	0.06%	1.52%	8.00%	0.0009%	0.0048%
Starbucks Corp	SBUX	$105,329	0.26%	2.45%	15.41%	0.0064%	0.0400%
Charles Schwab Corp/The	SCHW	n/a	N/A	1.59%	N/A	N/A	N/A
Sherwin-Williams Co/The	SHW	$77,911	0.19%	0.80%	10.94%	0.0015%	0.0210%
J M Smucker Co/The	SJM	$13,963	0.03%	3.22%	6.91%	0.0011%	0.0024%
Schlumberger NV	SLB	$69,514	0.17%	2.26%	20.37%	0.0039%	0.0349%
Snap-on Inc	SNA	$15,303	0.04%	2.57%	4.85%	0.0010%	0.0018%
Synopsys Inc	SNPS	$81,347	0.20%	0.00%	17.68%	0.0000%	0.0354%
Southern Co/The	SO	$75,882	0.19%	4.03%	4.50%	0.0075%	0.0084%
Simon Property Group Inc	SPG	$45,221	0.11%	5.48%	1.71%	0.0061%	0.0019%
S&P Global Inc	SPGI	$142,037	0.35%	0.81%	13.58%	0.0028%	0.0475%
Sempra	SRE	$45,035	0.11%	3.33%	4.95%	0.0037%	0.0055%
STERIS PLC	STE	n/a	N/A	0.95%	N/A	N/A	N/A
Steel Dynamics Inc	STLD	$19,530	0.05%	1.41%	-13.01%	0.0007%	-0.0063%
State Street Corp	STT	$22,305	0.05%	3.74%	7.85%	0.0021%	0.0043%
Seagate Technology Holdings PLC	STX	$17,951	0.04%	3.27%	-4.90%	0.0014%	-0.0022%
Constellation Brands Inc	STZ	$44,800	0.11%	1.45%	10.63%	0.0016%	0.0117%
Stanley Black & Decker Inc	SWK	$14,304	0.04%	3.47%	9.00%	0.0012%	0.0032%
Skyworks Solutions Inc	SWKS	$16,737	0.04%	2.60%	9.03%	0.0011%	0.0037%
Synchrony Financial	SYF	n/a	N/A	2.57%	N/A	N/A	N/A

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Stryker Corp	SYK	$127,447	0.31%	0.95%	8.20%	0.0030%	0.0257%
Sysco Corp	SYY	$40,289	0.10%	2.47%	14.00%	0.0025%	0.0139%
AT&T Inc	T	$126,484	0.31%	6.27%	-4.61%	0.0195%	-0.0144%
Molson Coors Beverage Co	TAP	$12,417	0.03%	2.65%	12.08%	0.0008%	0.0037%
TransDigm Group Inc	TDG	$60,746	0.15%	0.00%	15.56%	0.0000%	0.0233%
Teledyne Technologies Inc	TDY	$19,746	0.05%	0.00%	8.03%	0.0000%	0.0039%
Bio-Techne Corp	TECH	$11,121	0.03%	0.46%	5.00%	0.0001%	0.0014%
TE Connectivity Ltd	TEL	$43,908	0.11%	1.66%	5.27%	0.0018%	0.0057%
Teradyne Inc	TER	$14,767	0.04%	0.50%	6.00%	0.0002%	0.0022%
Truist Financial Corp	TFC	$49,429	0.12%	5.61%	7.33%	0.0068%	0.0089%
Teleflex Inc	TFX	$11,411	0.03%	0.56%	7.00%	0.0002%	0.0020%
Target Corp	TGT	$64,208	0.16%	3.16%	15.29%	0.0050%	0.0242%
TJX Cos Inc/The	TJX	$108,167	0.27%	1.40%	6.38%	0.0037%	0.0170%
Thermo Fisher Scientific Inc	TMO	n/a	N/A	0.26%	N/A	N/A	N/A
T-Mobile US Inc	TMUS	$192,800	0.47%	1.61%	5.25%	0.0077%	0.0249%
Tapestry Inc	TPR	$8,890	0.02%	3.61%	11.00%	0.0008%	0.0024%
Targa Resources Corp	TRGP	$18,944	0.05%	2.35%	14.00%	0.0011%	0.0065%
Trimble Inc	TRMB	n/a	N/A	0.00%	N/A	N/A	N/A
T Rowe Price Group Inc	TROW	$24,235	0.06%	4.57%	-1.21%	0.0027%	-0.0007%
Travelers Cos Inc/The	TRV	$48,232	0.12%	1.89%	19.03%	0.0022%	0.0226%
Tractor Supply Co	TSCO	$24,282	0.06%	1.83%	3.42%	0.0011%	0.0020%
Tesla Inc	TSLA	$596,479	1.47%	0.00%	2.00%	0.0000%	0.0294%
Tyson Foods Inc	TSN	$15,681	0.04%	3.58%	46.71%	0.0014%	0.0180%
Trane Technologies PLC	TT	$57,356	0.14%	1.19%	13.04%	0.0017%	0.0184%
Take-Two Interactive Software Inc	TTWO	$28,049	0.07%	0.00%	35.02%	0.0000%	0.0242%
Texas Instruments Inc	TXN	$145,549	0.36%	3.25%	10.00%	0.0116%	0.0358%
Textron Inc	TXT	n/a	N/A	0.09%	N/A	N/A	N/A
Tyler Technologies Inc	TYL	n/a	N/A	0.00%	N/A	N/A	N/A
United Airlines Holdings Inc	UAL	$13,573	0.03%	0.00%	49.56%	0.0000%	0.0166%
Uber Technologies Inc	UBER	$134,316	0.33%	0.00%	68.00%	0.0000%	0.2249%
UDR Inc	UDR	$11,848	0.03%	4.66%	6.08%	0.0014%	0.0018%
Universal Health Services Inc	UHS	$9,689	0.02%	0.50%	11.38%	0.0001%	0.0027%
Ulta Beauty Inc	ULTA	$24,381	0.06%	0.00%	6.26%	0.0000%	0.0038%
UnitedHealth Group Inc	UNH	$473,321	1.17%	1.47%	10.61%	0.0171%	0.1237%
Union Pacific Corp	UNP	$148,699	0.37%	2.13%	11.00%	0.0078%	0.0403%
United Parcel Service Inc	UPS	$102,630	0.25%	4.59%	-0.39%	0.0116%	-0.0010%
United Rentals Inc	URI	$42,022	0.10%	1.04%	6.85%	0.0011%	0.0071%
US Bancorp	USB	$64,719	0.16%	4.72%	6.00%	0.0075%	0.0096%
Visa Inc	V	$432,185	1.06%	0.76%	13.41%	0.0081%	0.1427%
VF Corp	VFC	$6,401	0.02%	2.19%	3.10%	0.0003%	0.0005%
VICI Properties Inc	VICI	$31,160	0.08%	5.51%	4.78%	0.0042%	0.0037%
Valero Energy Corp	VLO	$47,289	0.12%	3.08%	8.16%	0.0036%	0.0095%
Veralto Corp	VLTO	n/a	N/A	0.47%	N/A	N/A	N/A
Vulcan Materials Co	VMC	$30,031	0.07%	0.76%	22.79%	0.0006%	0.0169%
Verisk Analytics Inc	VRSK	$35,019	0.09%	0.56%	11.70%	0.0005%	0.0101%
VeriSign Inc	VRSN	$20,306	0.05%	0.00%	11.50%	0.0000%	0.0058%
Vertex Pharmaceuticals Inc	VRTX	$111,675	0.28%	0.00%	13.40%	0.0000%	0.0368%
Ventas Inc	VTR	$18,666	0.05%	3.88%	8.66%	0.0018%	0.0040%
Viatris Inc	VTRS	$14,120	0.03%	4.08%	-2.58%	0.0014%	-0.0009%
Verizon Communications Inc	VZ	$178,039	0.44%	6.28%	-4.10%	0.0275%	-0.0180%
Westinghouse Air Brake Technologie	WAB	$23,572	0.06%	0.52%	14.08%	0.0003%	0.0082%
Waters Corp	WAT	$18,785	0.05%	0.00%	4.87%	0.0000%	0.0023%
Walgreens Boots Alliance Inc	WBA	$19,464	0.05%	4.43%	0.31%	0.0021%	0.0001%
Warner Bros Discovery Inc	WBD	$24,434	0.06%	0.00%	91.04%	0.0000%	0.0548%
Western Digital Corp	WDC	$18,563	0.05%	0.00%	-13.91%	0.0000%	-0.0064%
WEC Energy Group Inc	WEC	$25,475	0.06%	4.14%	6.39%	0.0026%	0.0040%
Welltower Inc	WELL	$48,108	0.12%	2.82%	9.22%	0.0033%	0.0109%
Wells Fargo & Co	WFC	$180,593	0.44%	2.79%	13.41%	0.0124%	0.0596%
Whirlpool Corp	WHR	$6,024	0.01%	6.39%	-1.36%	0.0009%	-0.0002%
Waste Management Inc	WM	$74,767	0.18%	1.51%	10.39%	0.0028%	0.0191%
Williams Cos Inc/The	WMB	$42,164	0.10%	5.48%	3.50%	0.0057%	0.0036%
Walmart Inc	WMT	$444,892	1.10%	1.38%	3.00%	0.0151%	0.0329%
W R Berkley Corp	WRB	$21,006	0.05%	0.54%	15.00%	0.0003%	0.0078%
Westrock Co	WRK	$10,327	0.03%	3.01%	5.70%	0.0008%	0.0014%
West Pharmaceutical Services Inc	WST	$27,600	0.07%	0.21%	18.89%	0.0001%	0.0128%
Willis Towers Watson PLC	WTW	$25,433	0.06%	1.36%	10.94%	0.0009%	0.0068%
Weyerhaeuser Co	WY	n/a	N/A	0.43%	N/A	N/A	N/A
Wynn Resorts Ltd	WYNN	$10,665	0.03%	1.06%	140.51%	0.0003%	0.0369%
Xcel Energy Inc	XEL	$33,037	0.08%	3.47%	6.21%	0.0028%	0.0051%
Exxon Mobil Corp	XOM	$411,871	1.01%	3.70%	13.21%	0.0375%	0.1340%
DENTSPLY SIRONA Inc	XRAY	$7,362	0.02%	1.61%	7.93%	0.0003%	0.0014%
Xylem Inc/NY	XYL	n/a	N/A	1.17%	N/A	N/A	N/A
Yum! Brands Inc	YUM	$36,297	0.09%	2.07%	11.49%	0.0018%	0.0103%
Zimmer Biomet Holdings Inc	ZBH	$26,248	0.06%	0.76%	7.19%	0.0005%	0.0046%
Zebra Technologies Corp	ZBRA	n/a	N/A	0.00%	N/A	N/A	N/A
Zions Bancorp NA	ZION	$6,208	0.02%	3.91%	-9.40%	0.0006%	-0.0014%
Zoetis Inc	ZTS	$86,226	0.21%	0.92%	10.91%	0.0020%	0.0232%
		$40,608,876					

[4] Source: Bloomberg Professional as of January 31, 2024
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Bloomberg Professional as of January 31, 2024
[7] Source: Bloomberg Professional as of January 31, 2024
[8] Equals [5] x [6]
[9] Equals [5] x [7]

Expected Market Return
Market DCF Based Method - Value Line EPS Growth

[1] Market Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.49%
[2] Market Cap. Weighted Estimate of the S&P 500 Growth Rate	12.66%
[3] Market Cap. Weighted Estimated Required Market Return	14.25%

Notes:
[1] Equals Sum of Col. [8]
[2] Equals Sum of Col. [9]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate ($ mill)	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Agilent Technologies Inc	A	$38,120	0.10%	0.73%	13.50%	0.0007%	0.0129%
American Airlines Group Inc	AAL	n/a	N/A	0.00%	N/A	N/A	N/A
Apple Inc	AAPL	$2,851,174	7.15%	0.52%	8.50%	0.0372%	0.6079%
AbbVie Inc	ABBV	$290,254	0.73%	3.77%	2.00%	0.0275%	0.0146%
Airbnb Inc	ABNB	n/a	N/A	0.00%	N/A	N/A	N/A
Abbott Laboratories	ABT	$196,435	0.49%	1.94%	4.50%	0.0096%	0.0222%
Arch Capital Group Ltd	ACGL	$30,761	0.08%	0.00%	26.00%	0.0000%	0.0201%
Accenture PLC	ACN	$242,530	0.61%	1.42%	12.50%	0.0086%	0.0760%
Adobe Inc	ADBE	$279,237	0.70%	0.00%	14.50%	0.0000%	0.1016%
Analog Devices Inc	ADI	$95,380	0.24%	1.79%	11.50%	0.0043%	0.0275%
Archer-Daniels-Midland Co	ADM	$29,645	0.07%	3.60%	7.50%	0.0027%	0.0056%
Automatic Data Processing Inc	ADP	$100,942	0.25%	2.28%	11.00%	0.0058%	0.0279%
Autodesk Inc	ADSK	$54,294	0.14%	0.00%	10.00%	0.0000%	0.0136%
Ameren Corp	AEE	$18,293	0.05%	3.62%	6.50%	0.0017%	0.0030%
American Electric Power Co Inc	AEP	$40,256	0.10%	4.50%	6.50%	0.0045%	0.0066%
AES Corp/The	AES	$11,169	0.03%	4.14%	14.00%	0.0012%	0.0039%
Aflac Inc	AFL	$49,287	0.12%	2.37%	8.00%	0.0029%	0.0099%
American International Group Inc	AIG	$48,799	0.12%	2.07%	14.00%	0.0025%	0.0171%
Assurant Inc	AIZ	$8,833	0.02%	1.71%	10.50%	0.0004%	0.0023%
Arthur J Gallagher & Co	AJG	$50,306	0.13%	1.03%	22.00%	0.0013%	0.0278%
Akamai Technologies Inc	AKAM	$18,587	0.05%	0.00%	5.00%	0.0000%	0.0023%
Albemarle Corp	ALB	$13,465	0.03%	1.39%	-4.50%	0.0005%	-0.0015%
Align Technology Inc	ALGN	$20,474	0.05%	0.00%	17.00%	0.0000%	0.0087%
Allstate Corp/The	ALL	$40,627	0.10%	2.29%	10.50%	0.0023%	0.0107%
Allegion plc	ALLE	$10,876	0.03%	1.45%	10.00%	0.0004%	0.0027%
Applied Materials Inc	AMAT	$136,708	0.34%	0.78%	4.00%	0.0027%	0.0137%
Amcor PLC	AMCR	$13,630	0.03%	5.30%	11.50%	0.0018%	0.0039%
Advanced Micro Devices Inc	AMD	$270,951	0.68%	0.00%	25.50%	0.0000%	0.1733%
AMETEK Inc	AME	$37,401	0.09%	0.62%	13.00%	0.0006%	0.0122%
Amgen Inc	AMGN	$168,185	0.42%	2.86%	5.50%	0.0121%	0.0232%
Ameriprise Financial Inc	AMP	$39,146	0.10%	1.40%	11.00%	0.0014%	0.0108%
American Tower Corp	AMT	$91,205	0.23%	3.48%	5.00%	0.0080%	0.0114%
Amazon.com Inc	AMZN	$1,603,842	4.02%	0.00%	19.50%	0.0000%	0.7845%
Arista Networks Inc	ANET	$80,475	0.20%	0.00%	17.00%	0.0000%	0.0343%
ANSYS Inc	ANSS	$28,494	0.07%	0.00%	8.50%	0.0000%	0.0061%
Aon PLC	AON	$59,750	0.15%	0.82%	9.50%	0.0012%	0.0142%
A O Smith Corp	AOS	$9,533	0.02%	1.65%	11.50%	0.0004%	0.0027%
APA Corp	APA	$9,610	0.02%	3.19%	19.50%	0.0008%	0.0047%
Air Products and Chemicals Inc	APD	$56,826	0.14%	2.77%	10.50%	0.0039%	0.0150%
Amphenol Corp	APH	$60,489	0.15%	0.87%	12.50%	0.0013%	0.0190%
Aptiv PLC	APTV	$23,005	0.06%	0.00%	33.50%	0.0000%	0.0193%
Alexandria Real Estate Equities Inc	ARE	$21,154	0.05%	4.20%	10.00%	0.0022%	0.0053%
Atmos Energy Corp	ATO	$17,186	0.04%	2.83%	7.00%	0.0012%	0.0030%
AvalonBay Communities Inc	AVB	$25,422	0.06%	3.80%	6.00%	0.0024%	0.0038%
Broadcom Inc	AVGO	$552,406	1.39%	1.78%	30.00%	0.0247%	0.4157%
Avery Dennison Corp	AVY	$16,062	0.04%	1.62%	9.50%	0.0007%	0.0038%
American Water Works Co Inc	AWK	$24,147	0.06%	2.28%	3.00%	0.0014%	0.0018%
Axon Enterprise Inc	AXON	$18,663	0.05%	0.00%	24.00%	0.0000%	0.0112%
American Express Co	AXP	$145,135	0.36%	1.20%	8.50%	0.0044%	0.0309%
AutoZone Inc	AZO	$47,763	0.12%	0.00%	13.00%	0.0000%	0.0156%
Boeing Co/The	BA	n/a	N/A	0.00%	N/A	N/A	N/A
Bank of America Corp	BAC	$268,526	0.67%	2.82%	5.00%	0.0190%	0.0337%
Ball Corp	BALL	$17,483	0.04%	1.44%	10.50%	0.0006%	0.0046%
Baxter International Inc	BAX	$19,628	0.05%	3.00%	6.00%	0.0015%	0.0030%
Bath & Body Works Inc	BBWI	$9,639	0.02%	1.88%	26.50%	0.0005%	0.0064%
Best Buy Co Inc	BBY	$15,614	0.04%	5.08%	3.00%	0.0020%	0.0012%
Becton Dickinson & Co	BDX	$69,146	0.17%	1.59%	5.00%	0.0028%	0.0087%
Franklin Resources Inc	BEN	$14,022	0.04%	4.66%	2.00%	0.0016%	0.0007%
Brown-Forman Corp	BF/B	$16,825	0.04%	1.59%	16.50%	0.0007%	0.0070%
Bunge Global SA	BG	$14,220	0.04%	3.01%	1.50%	0.0011%	0.0005%
Biogen Inc	BIIB	$35,741	0.09%	0.00%	-6.50%	0.0000%	-0.0058%
Bio-Rad Laboratories Inc	BIO	$7,720	0.02%	0.00%	11.50%	0.0000%	0.0022%
Bank of New York Mellon Corp/The	BK	$42,113	0.11%	3.03%	7.00%	0.0032%	0.0074%
Booking Holdings Inc	BKNG	$122,376	0.31%	0.00%	22.00%	0.0000%	0.0675%
Baker Hughes Co	BKR	n/a	N/A	2.81%	N/A	N/A	N/A
Builders FirstSource Inc	BLDR	$21,429	0.05%	0.00%	11.00%	0.0000%	0.0059%
BlackRock Inc	BLK	$115,188	0.29%	2.63%	7.50%	0.0076%	0.0217%
Bristol-Myers Squibb Co	BMY	n/a	N/A	4.91%	N/A	N/A	N/A
Broadridge Financial Solutions Inc	BR	$24,024	0.06%	1.57%	8.50%	0.0009%	0.0051%
Berkshire Hathaway Inc	BRK/B	$502,091	1.26%	0.00%	6.00%	0.0000%	0.0756%
Brown & Brown Inc	BRO	$22,074	0.06%	0.67%	6.50%	0.0004%	0.0036%
Boston Scientific Corp	BSX	$92,675	0.23%	0.00%	13.50%	0.0000%	0.0314%
BorgWarner Inc	BWA	$7,968	0.02%	1.30%	6.50%	0.0003%	0.0013%
Blackstone Inc	BX	$89,524	0.22%	3.02%	15.00%	0.0068%	0.0337%
Boston Properties Inc	BXP	$10,437	0.03%	5.89%	-1.00%	0.0015%	-0.0003%
Citigroup Inc	C	$106,897	0.27%	3.77%	2.50%	0.0101%	0.0067%

		[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Market Capitalization Excluding No Growth Rate ($ mill)	Weight in Index	Dividend Yield	Long-Term Growth Est.	Weighted Dividend Yield	Weighted Long-Term Growth Rate
Conagra Brands Inc	CAG	$13,934	0.03%	4.80%	3.50%	0.0017%	0.0012%
Cardinal Health Inc	CAH	$26,912	0.07%	1.83%	7.50%	0.0012%	0.0051%
Carrier Global Corp	CARR	$49,111	0.12%	1.39%	13.50%	0.0017%	0.0166%
Caterpillar Inc	CAT	$152,883	0.38%	1.73%	14.50%	0.0066%	0.0556%
Chubb Ltd	CB	$99,291	0.25%	1.40%	17.00%	0.0035%	0.0423%
Cboe Global Markets Inc	CBOE	$19,406	0.05%	1.20%	13.00%	0.0006%	0.0063%
CBRE Group Inc	CBRE	$26,307	0.07%	0.00%	8.50%	0.0000%	0.0056%
Crown Castle Inc	CCI	$46,981	0.12%	5.78%	7.00%	0.0068%	0.0082%
Carnival Corp	CCL	n/a	N/A	0.00%	N/A	N/A	N/A
Dayforce Inc	CDAY	n/a	N/A	0.00%	N/A	N/A	N/A
Cadence Design Systems Inc	CDNS	$78,479	0.20%	0.00%	12.00%	0.0000%	0.0236%
CDW Corp/DE	CDW	$30,371	0.08%	1.09%	7.00%	0.0008%	0.0053%
Celanese Corp	CE	$15,924	0.04%	1.91%	4.50%	0.0008%	0.0018%
Constellation Energy Corp	CEG	n/a	N/A	0.92%	N/A	N/A	N/A
CF Industries Holdings Inc	CF	$14,427	0.04%	2.65%	7.50%	0.0010%	0.0027%
Citizens Financial Group Inc	CFG	$15,252	0.04%	5.14%	4.50%	0.0020%	0.0017%
Church & Dwight Co Inc	CHD	$24,601	0.06%	1.09%	6.00%	0.0007%	0.0037%
CH Robinson Worldwide Inc	CHRW	$9,809	0.02%	2.90%	5.50%	0.0007%	0.0014%
Charter Communications Inc	CHTR	$54,835	0.14%	0.00%	12.50%	0.0000%	0.0172%
Cigna Group/The	CI	$88,064	0.22%	1.63%	10.00%	0.0036%	0.0221%
Cincinnati Financial Corp	CINF	$17,385	0.04%	2.92%	13.00%	0.0013%	0.0057%
Colgate-Palmolive Co	CL	$69,328	0.17%	2.28%	8.50%	0.0040%	0.0148%
Clorox Co/The	CLX	$18,020	0.05%	3.30%	11.00%	0.0015%	0.0050%
Comerica Inc	CMA	$6,934	0.02%	5.40%	3.00%	0.0009%	0.0005%
Comcast Corp	CMCSA	$184,411	0.46%	2.66%	9.00%	0.0123%	0.0416%
CME Group Inc	CME	$74,100	0.19%	2.14%	7.50%	0.0040%	0.0139%
Chipotle Mexican Grill Inc	CMG	$66,109	0.17%	0.00%	21.50%	0.0000%	0.0357%
Cummins Inc	CMI	$33,920	0.09%	2.81%	9.00%	0.0024%	0.0077%
CMS Energy Corp	CMS	$16,677	0.04%	3.41%	5.50%	0.0014%	0.0023%
Centene Corp	CNC	$40,231	0.10%	0.00%	10.00%	0.0000%	0.0101%
CenterPoint Energy Inc	CNP	$17,586	0.04%	2.86%	8.50%	0.0013%	0.0037%
Capital One Financial Corp	COF	$51,476	0.13%	1.77%	4.00%	0.0023%	0.0052%
Cooper Cos Inc/The	COO	$18,475	0.05%	0.00%	12.00%	0.0000%	0.0056%
ConocoPhillips	COP	$132,835	0.33%	0.52%	9.00%	0.0017%	0.0300%
Cencora Inc	COR	$46,415	0.12%	0.88%	9.00%	0.0010%	0.0105%
Costco Wholesale Corp	COST	$308,338	0.77%	0.59%	10.50%	0.0045%	0.0812%
Campbell Soup Co	CPB	$13,304	0.03%	3.32%	5.00%	0.0011%	0.0017%
Copart Inc	CPRT	$46,129	0.12%	0.00%	7.00%	0.0000%	0.0081%
Camden Property Trust	CPT	$10,019	0.03%	4.26%	-3.00%	0.0011%	-0.0008%
Charles River Laboratories Internatic	CRL	$11,095	0.03%	0.00%	8.00%	0.0000%	0.0022%
Salesforce Inc	CRM	$272,095	0.68%	0.00%	18.00%	0.0000%	0.1229%
Cisco Systems Inc	CSCO	$203,905	0.51%	3.11%	6.50%	0.0159%	0.0332%
CoStar Group Inc	CSGP	$34,090	0.09%	0.00%	14.00%	0.0000%	0.0120%
CSX Corp	CSX	$70,548	0.18%	1.23%	8.00%	0.0022%	0.0142%
Cintas Corp	CTAS	$61,286	0.15%	0.89%	14.00%	0.0014%	0.0215%
Catalent Inc	CTLT	$9,328	0.02%	0.00%	21.00%	0.0000%	0.0049%
Coterra Energy Inc	CTRA	n/a	N/A	3.22%	N/A	N/A	N/A
Cognizant Technology Solutions Cor	CTSH	$38,669	0.10%	1.50%	8.00%	0.0015%	0.0078%
Corteva Inc	CTVA	$32,058	0.08%	1.41%	13.50%	0.0011%	0.0109%
CVS Health Corp	CVS	$95,707	0.24%	3.58%	8.50%	0.0086%	0.0204%
Chevron Corp	CVX	$278,311	0.70%	4.10%	19.50%	0.0286%	0.1361%
Caesars Entertainment Inc	CZR	n/a	N/A	0.00%	N/A	N/A	N/A
Dominion Energy Inc	D	$38,257	0.10%	5.84%	0.50%	0.0056%	0.0005%
Delta Air Lines Inc	DAL	n/a	N/A	1.02%	N/A	N/A	N/A
DuPont de Nemours Inc	DD	$26,577	0.07%	2.33%	9.50%	0.0016%	0.0063%
Deere & Co	DE	$110,198	0.28%	1.49%	12.50%	0.0041%	0.0346%
Discover Financial Services	DFS	$26,386	0.07%	2.65%	4.00%	0.0018%	0.0026%
Dollar General Corp	DG	$28,989	0.07%	1.79%	2.00%	0.0013%	0.0015%
Quest Diagnostics Inc	DGX	$14,440	0.04%	2.21%	2.50%	0.0008%	0.0009%
DR Horton Inc	DHI	$47,420	0.12%	0.84%	3.00%	0.0010%	0.0036%
Danaher Corp	DHR	$177,341	0.44%	0.40%	7.50%	0.0018%	0.0334%
Walt Disney Co/The	DIS	$175,802	0.44%	0.62%	30.00%	0.0028%	0.1323%
Digital Realty Trust Inc	DLR	$42,538	0.11%	3.47%	-3.00%	0.0037%	-0.0032%
Dollar Tree Inc	DLTR	$28,458	0.07%	0.00%	9.00%	0.0000%	0.0064%
Dover Corp	DOV	$20,953	0.05%	1.36%	6.50%	0.0007%	0.0034%
Dow Inc	DOW	$37,643	0.09%	5.22%	3.00%	0.0049%	0.0028%
Domino's Pizza Inc	DPZ	$14,867	0.04%	1.14%	11.50%	0.0004%	0.0043%
Darden Restaurants Inc	DRI	$19,414	0.05%	3.22%	15.00%	0.0016%	0.0073%
DTE Energy Co	DTE	$21,728	0.05%	3.87%	4.50%	0.0021%	0.0025%
Duke Energy Corp	DUK	$73,885	0.19%	4.28%	5.00%	0.0079%	0.0093%
DaVita Inc	DVA	$9,875	0.02%	0.00%	8.00%	0.0000%	0.0020%
Devon Energy Corp	DVN	$26,922	0.07%	7.33%	10.50%	0.0049%	0.0071%
Dexcom Inc	DXCM	n/a	N/A	0.00%	N/A	N/A	N/A
Electronic Arts Inc	EA	$37,004	0.09%	0.55%	17.50%	0.0005%	0.0162%
eBay Inc	EBAY	$21,315	0.05%	2.43%	7.00%	0.0013%	0.0037%
Ecolab Inc	ECL	$56,520	0.14%	1.15%	10.00%	0.0016%	0.0142%
Consolidated Edison Inc	ED	$31,354	0.08%	3.65%	6.00%	0.0029%	0.0047%
Equifax Inc	EFX	$30,107	0.08%	0.64%	3.50%	0.0005%	0.0026%
Everest Group Ltd	EG	$16,704	0.04%	1.82%	10.00%	0.0008%	0.0042%
Edison International	EIX	$25,883	0.06%	4.62%	4.50%	0.0030%	0.0029%
Estee Lauder Cos Inc/The	EL	$30,662	0.08%	2.00%	8.00%	0.0015%	0.0062%
Elevance Health Inc	ELV	$115,938	0.29%	1.32%	12.50%	0.0038%	0.0364%
Eastman Chemical Co	EMN	$9,906	0.02%	3.88%	6.00%	0.0010%	0.0015%
Emerson Electric Co	EMR	$52,295	0.13%	2.29%	6.50%	0.0030%	0.0085%
Enphase Energy Inc	ENPH	$14,219	0.04%	0.00%	21.00%	0.0000%	0.0075%
EOG Resources Inc	EOG	$66,357	0.17%	3.20%	15.00%	0.0053%	0.0250%
EPAM Systems Inc	EPAM	$16,047	0.04%	0.00%	20.50%	0.0000%	0.0083%
Equinix Inc	EQIX	$77,901	0.20%	2.05%	15.00%	0.0040%	0.0293%
Equity Residential	EQR	$22,830	0.06%	4.40%	-5.00%	0.0025%	-0.0029%
EQT Corp	EQT	n/a	N/A	1.78%	N/A	N/A	N/A
Eversource Energy	ES	$18,927	0.05%	5.27%	6.00%	0.0025%	0.0028%

		[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Market Capitalization Excluding No Growth Rate ($ mill)	Weight in Index	Dividend Yield	Long-Term Growth Est.	Weighted Dividend Yield	Weighted Long-Term Growth Rate
Essex Property Trust Inc	ESS	$14,972	0.04%	3.96%	1.50%	0.0015%	0.0006%
Eaton Corp PLC	ETN	$98,260	0.25%	1.40%	12.50%	0.0034%	0.0308%
Entergy Corp	ETR	$21,095	0.05%	4.53%	0.50%	0.0024%	0.0003%
Etsy Inc	ETSY	$7,970	0.02%	0.00%	2.00%	0.0000%	0.0004%
Evergy Inc	EVRG	$11,656	0.03%	5.06%	7.50%	0.0015%	0.0022%
Edwards Lifesciences Corp	EW	$47,592	0.12%	0.00%	10.50%	0.0000%	0.0125%
Exelon Corp	EXC	n/a	N/A	4.14%	N/A	N/A	N/A
Expeditors International of Washingt	EXPD	$18,367	0.05%	1.09%	10.00%	0.0005%	0.0046%
Expedia Group Inc	EXPE	n/a	N/A	0.00%	N/A	N/A	N/A
Extra Space Storage Inc	EXR	$30,517	0.08%	4.49%	5.00%	0.0034%	0.0038%
Ford Motor Co	F	$46,084	0.12%	5.12%	43.00%	0.0059%	0.0497%
Diamondback Energy Inc	FANG	n/a	N/A	8.77%	N/A	N/A	N/A
Fastenal Co	FAST	$39,026	0.10%	2.29%	6.50%	0.0022%	0.0064%
Freeport-McMoRan Inc	FCX	$56,915	0.14%	1.51%	12.50%	0.0022%	0.0178%
FactSet Research Systems Inc	FDS	$18,126	0.05%	0.82%	10.50%	0.0004%	0.0048%
FedEx Corp	FDX	$60,297	0.15%	2.09%	7.00%	0.0032%	0.0106%
FirstEnergy Corp	FE	$21,048	0.05%	4.47%	4.50%	0.0024%	0.0024%
F5 Inc	FFIV	$10,801	0.03%	0.00%	10.00%	0.0000%	0.0027%
Fiserv Inc	FI	$85,148	0.21%	0.00%	9.50%	0.0000%	0.0203%
Fair Isaac Corp	FICO	$29,793	0.07%	0.00%	19.50%	0.0000%	0.0146%
Fidelity National Information Services	FIS	n/a	N/A	3.34%	N/A	N/A	N/A
Fifth Third Bancorp	FITB	$23,322	0.06%	4.09%	4.00%	0.0024%	0.0023%
FleetCor Technologies Inc	FLT	$20,934	0.05%	0.00%	15.50%	0.0000%	0.0081%
FMC Corp	FMC	$7,011	0.02%	4.13%	10.00%	0.0007%	0.0018%
Fox Corp	FOX	n/a	N/A	1.73%	N/A	N/A	N/A
Fox Corp	FOXA	$7,985	0.02%	1.61%	8.00%	0.0003%	0.0016%
Federal Realty Investment Trust	FRT	$8,303	0.02%	4.29%	2.50%	0.0009%	0.0005%
First Solar Inc	FSLR	$15,631	0.04%	0.00%	27.50%	0.0000%	0.0108%
Fortinet Inc	FTNT	$49,523	0.12%	0.00%	24.00%	0.0000%	0.0298%
Fortive Corp	FTV	$27,475	0.07%	0.41%	16.00%	0.0003%	0.0110%
General Dynamics Corp	GD	$72,315	0.18%	1.99%	9.50%	0.0036%	0.0172%
General Electric Co	GE	$144,124	0.36%	0.24%	29.50%	0.0009%	0.1066%
GE HealthCare Technologies Inc	GEHC	n/a	N/A	0.16%	N/A	N/A	N/A
Gen Digital Inc	GEN	$15,044	0.04%	2.13%	10.50%	0.0008%	0.0040%
Gilead Sciences Inc	GILD	$97,515	0.24%	3.83%	13.50%	0.0094%	0.0330%
General Mills Inc	GIS	$36,862	0.09%	3.64%	5.50%	0.0034%	0.0051%
Globe Life Inc	GL	$11,560	0.03%	0.73%	9.00%	0.0002%	0.0026%
Corning Inc	GLW	$27,720	0.07%	3.45%	17.50%	0.0024%	0.0122%
General Motors Co	GM	$44,792	0.11%	1.24%	7.50%	0.0014%	0.0084%
Generac Holdings Inc	GNRC	$6,983	0.02%	0.00%	11.00%	0.0000%	0.0019%
Alphabet Inc	GOOG	$804,148	2.02%	0.00%	13.00%	0.0000%	0.2622%
Alphabet Inc	GOOGL	n/a	N/A	0.00%	N/A	N/A	N/A
Genuine Parts Co	GPC	$19,660	0.05%	2.71%	9.00%	0.0013%	0.0044%
Global Payments Inc	GPN	$34,692	0.09%	0.75%	13.50%	0.0007%	0.0117%
Garmin Ltd	GRMN	$22,862	0.06%	2.44%	5.00%	0.0014%	0.0029%
Goldman Sachs Group Inc/The	GS	$125,230	0.31%	2.86%	1.50%	0.0090%	0.0047%
WW Grainger Inc	GWW	$44,454	0.11%	0.83%	11.50%	0.0009%	0.0128%
Halliburton Co	HAL	$31,909	0.08%	1.91%	27.50%	0.0015%	0.0220%
Hasbro Inc	HAS	$6,792	0.02%	5.72%	8.50%	0.0010%	0.0014%
Huntington Bancshares Inc/OH	HBAN	$18,433	0.05%	4.87%	10.50%	0.0023%	0.0049%
HCA Healthcare Inc	HCA	$81,610	0.20%	0.87%	12.50%	0.0018%	0.0256%
Home Depot Inc/The	HD	$351,288	0.88%	2.37%	6.50%	0.0209%	0.0573%
Hess Corp	HES	$43,164	0.11%	1.25%	23.50%	0.0013%	0.0254%
Hartford Financial Services Group In	HIG	$26,155	0.07%	2.16%	8.00%	0.0014%	0.0052%
Huntington Ingalls Industries Inc	HII	$10,285	0.03%	2.01%	10.00%	0.0005%	0.0026%
Hilton Worldwide Holdings Inc	HLT	n/a	N/A	0.31%	N/A	N/A	N/A
Hologic Inc	HOLX	$17,473	0.04%	0.00%	-3.50%	0.0000%	-0.0015%
Honeywell International Inc	HON	$133,340	0.33%	2.14%	10.50%	0.0071%	0.0351%
Hewlett Packard Enterprise Co	HPE	$19,877	0.05%	3.40%	7.50%	0.0017%	0.0037%
HP Inc	HPQ	$28,449	0.07%	3.84%	12.50%	0.0027%	0.0089%
Hormel Foods Corp	HRL	$16,608	0.04%	3.72%	7.50%	0.0015%	0.0031%
Henry Schein Inc	HSIC	$9,773	0.02%	0.00%	9.00%	0.0000%	0.0022%
Host Hotels & Resorts Inc	HST	$13,558	0.03%	4.16%	51.00%	0.0014%	0.0173%
Hershey Co/The	HSY	$29,009	0.07%	2.46%	9.50%	0.0018%	0.0069%
Hubbell Inc	HUBB	$17,994	0.05%	1.45%	10.00%	0.0007%	0.0045%
Humana Inc	HUM	$46,208	0.12%	0.94%	12.50%	0.0011%	0.0145%
Howmet Aerospace Inc	HWM	$23,165	0.06%	0.36%	12.00%	0.0002%	0.0070%
International Business Machines Cor	IBM	$167,703	0.42%	3.62%	3.00%	0.0152%	0.0126%
Intercontinental Exchange Inc	ICE	$72,879	0.18%	1.32%	6.50%	0.0024%	0.0119%
IDEXX Laboratories Inc	IDXX	$42,778	0.11%	0.00%	10.50%	0.0000%	0.0113%
IDEX Corp	IEX	$15,995	0.04%	1.21%	6.00%	0.0005%	0.0024%
International Flavors & Fragrances Ir	IFF	$20,596	0.05%	4.02%	2.50%	0.0021%	0.0013%
Illumina Inc	ILMN	$22,710	0.06%	0.00%	6.50%	0.0000%	0.0037%
Incyte Corp	INCY	$13,171	0.03%	0.00%	32.00%	0.0000%	0.0106%
Intel Corp	INTC	n/a	N/A	1.16%	N/A	N/A	N/A
Intuit Inc	INTU	$176,732	0.44%	0.57%	14.50%	0.0025%	0.0643%
Invitation Homes Inc	INVH	n/a	N/A	3.40%	N/A	N/A	N/A
International Paper Co	IP	$12,398	0.03%	5.16%	6.00%	0.0016%	0.0019%
Interpublic Group of Cos Inc/The	IPG	$12,635	0.03%	3.76%	8.50%	0.0012%	0.0027%
IQVIA Holdings Inc	IQV	$38,002	0.10%	0.00%	14.50%	0.0000%	0.0138%
Ingersoll Rand Inc	IR	$32,327	0.08%	0.10%	12.50%	0.0001%	0.0101%
Iron Mountain Inc	IRM	$19,715	0.05%	3.85%	4.00%	0.0019%	0.0020%
Intuitive Surgical Inc	ISRG	$133,257	0.33%	0.00%	12.50%	0.0000%	0.0418%
Gartner Inc	IT	$35,657	0.09%	0.00%	13.00%	0.0000%	0.0116%
Illinois Tool Works Inc	ITW	$78,501	0.20%	2.15%	11.00%	0.0042%	0.0217%
Invesco Ltd	IVZ	$7,116	0.02%	5.05%	3.00%	0.0009%	0.0005%
Jacobs Solutions Inc	J	$17,024	0.04%	0.86%	10.00%	0.0004%	0.0043%
JB Hunt Transport Services Inc	JBHT	$20,730	0.05%	0.86%	9.00%	0.0004%	0.0047%
Jabil Inc	JBL	$15,980	0.04%	0.26%	16.00%	0.0001%	0.0064%
Johnson Controls International plc	JCI	$35,907	0.09%	2.81%	11.00%	0.0025%	0.0099%
Jack Henry & Associates Inc	JKHY	$12,077	0.03%	1.25%	6.50%	0.0004%	0.0020%

		[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Market Capitalization Excluding No Growth Rate ($ mill)	Weight in Index	Dividend Yield	Long-Term Growth Est.	Weighted Dividend Yield	Weighted Long-Term Growth Rate
Johnson & Johnson	JNJ	$382,517	0.96%	3.00%	5.00%	0.0287%	0.0480%
Juniper Networks Inc	JNPR	$11,785	0.03%	2.38%	10.50%	0.0007%	0.0031%
JPMorgan Chase & Co	JPM	$504,076	1.26%	2.41%	8.50%	0.0305%	0.1075%
Kellanova	K	$18,756	0.05%	4.09%	1.50%	0.0019%	0.0007%
Keurig Dr Pepper Inc	KDP	$43,964	0.11%	2.74%	12.50%	0.0030%	0.0138%
KeyCorp	KEY	n/a	N/A	5.64%	N/A	N/A	N/A
Keysight Technologies Inc	KEYS	$26,827	0.07%	0.00%	13.00%	0.0000%	0.0087%
Kraft Heinz Co/The	KHC	$45,541	0.11%	4.31%	5.00%	0.0049%	0.0057%
Kimco Realty Corp	KIM	$13,569	0.03%	4.75%	11.00%	0.0016%	0.0037%
KLA Corp	KLAC	$80,334	0.20%	0.98%	13.50%	0.0020%	0.0272%
Kimberly-Clark Corp	KMB	$40,881	0.10%	4.03%	7.00%	0.0041%	0.0072%
Kinder Morgan Inc	KMI	$37,609	0.09%	6.68%	17.50%	0.0063%	0.0165%
CarMax Inc	KMX	$11,241	0.03%	0.00%	-3.50%	0.0000%	-0.0010%
Coca-Cola Co/The	KO	$257,200	0.65%	3.09%	8.00%	0.0200%	0.0516%
Kroger Co/The	KR	$33,194	0.08%	2.51%	6.00%	0.0021%	0.0050%
Kenvue Inc	KVUE	n/a	N/A	3.85%	N/A	N/A	N/A
Loews Corp	L	$16,266	0.04%	0.34%	24.50%	0.0001%	0.0100%
Leidos Holdings Inc	LDOS	$15,190	0.04%	1.38%	6.00%	0.0005%	0.0023%
Lennar Corp	LEN	$37,037	0.09%	1.33%	4.50%	0.0012%	0.0042%
Laboratory Corp of America Holdings	LH	$18,873	0.05%	1.30%	-3.00%	0.0006%	-0.0014%
L3Harris Technologies Inc	LHX	$39,504	0.10%	2.19%	16.00%	0.0022%	0.0159%
Linde PLC	LIN	$196,298	0.49%	1.26%	8.50%	0.0062%	0.0419%
LKQ Corp	LKQ	$12,489	0.03%	2.57%	7.00%	0.0008%	0.0022%
Eli Lilly & Co	LLY	$612,882	1.54%	0.81%	19.00%	0.0124%	0.2921%
Lockheed Martin Corp	LMT	$103,764	0.26%	2.93%	7.00%	0.0076%	0.0182%
Alliant Energy Corp	LNT	$12,297	0.03%	3.95%	6.50%	0.0012%	0.0020%
Lowe's Cos Inc	LOW	$122,407	0.31%	2.07%	8.00%	0.0063%	0.0246%
Lam Research Corp	LRCX	$108,182	0.27%	0.97%	9.00%	0.0026%	0.0244%
Lululemon Athletica Inc	LULU	$54,946	0.14%	0.00%	16.50%	0.0000%	0.0227%
Southwest Airlines Co	LUV	n/a	N/A	2.41%	N/A	N/A	N/A
Las Vegas Sands Corp	LVS	n/a	N/A	1.64%	N/A	N/A	N/A
Lamb Weston Holdings Inc	LW	$14,789	0.04%	1.41%	12.00%	0.0005%	0.0045%
LyondellBasell Industries NV	LYB	$30,529	0.08%	5.31%	0.50%	0.0041%	0.0004%
Live Nation Entertainment Inc	LYV	n/a	N/A	0.00%	N/A	N/A	N/A
Mastercard Inc	MA	$417,981	1.05%	0.59%	16.00%	0.0062%	0.1678%
Mid-America Apartment Communities	MAA	$14,747	0.04%	4.65%	-12.50%	0.0017%	-0.0046%
Marriott International Inc/MD	MAR	$70,407	0.18%	0.87%	17.50%	0.0015%	0.0309%
Masco Corp	MAS	$15,107	0.04%	1.69%	6.00%	0.0006%	0.0023%
McDonald's Corp	MCD	$212,322	0.53%	2.28%	10.50%	0.0122%	0.0559%
Microchip Technology Inc	MCHP	$46,086	0.12%	2.06%	10.00%	0.0024%	0.0116%
McKesson Corp	MCK	$66,516	0.17%	0.50%	9.00%	0.0008%	0.0150%
Moody's Corp	MCO	$71,743	0.18%	0.79%	6.00%	0.0014%	0.0108%
Mondelez International Inc	MDLZ	$102,435	0.26%	2.26%	11.00%	0.0058%	0.0283%
Medtronic PLC	MDT	$116,398	0.29%	3.15%	7.50%	0.0092%	0.0219%
MetLife Inc	MET	$51,310	0.13%	3.00%	7.50%	0.0039%	0.0097%
Meta Platforms Inc	META	$865,957	2.17%	0.00%	17.00%	0.0000%	0.3693%
MGM Resorts International	MGM	$14,814	0.04%	0.00%	25.00%	0.0000%	0.0093%
Mohawk Industries Inc	MHK	$6,639	0.02%	0.00%	2.50%	0.0000%	0.0004%
McCormick & Co Inc/MD	MKC	$17,138	0.04%	2.46%	4.50%	0.0011%	0.0019%
MarketAxess Holdings Inc	MKTX	$8,548	0.02%	1.31%	8.50%	0.0003%	0.0018%
Martin Marietta Materials Inc	MLM	$31,424	0.08%	0.58%	12.50%	0.0005%	0.0099%
Marsh & McLennan Cos Inc	MMC	$95,577	0.24%	1.47%	9.00%	0.0035%	0.0216%
3M Co	MMM	$52,111	0.13%	6.36%	4.50%	0.0083%	0.0059%
Monster Beverage Corp	MNST	$57,245	0.14%	0.00%	13.00%	0.0000%	0.0187%
Altria Group Inc	MO	$70,958	0.18%	9.77%	6.00%	0.0174%	0.0107%
Molina Healthcare Inc	MOH	$20,780	0.05%	0.00%	11.50%	0.0000%	0.0060%
Mosaic Co/The	MOS	$10,037	0.03%	2.74%	-3.00%	0.0007%	-0.0008%
Marathon Petroleum Corp	MPC	$62,878	0.16%	1.99%	14.50%	0.0031%	0.0229%
Monolithic Power Systems Inc	MPWR	$28,878	0.07%	0.66%	15.00%	0.0005%	0.0109%
Merck & Co Inc	MRK	$306,059	0.77%	2.55%	8.50%	0.0196%	0.0653%
Moderna Inc	MRNA	$38,529	0.10%	0.00%	-20.00%	0.0000%	-0.0193%
Marathon Oil Corp	MRO	$13,373	0.03%	1.93%	25.50%	0.0006%	0.0086%
Morgan Stanley	MS	$143,188	0.36%	3.90%	7.50%	0.0140%	0.0269%
MSCI Inc	MSCI	$47,351	0.12%	1.07%	12.50%	0.0013%	0.0148%
Microsoft Corp	MSFT	$2,954,193	7.41%	0.75%	10.50%	0.0559%	0.7781%
Motorola Solutions Inc	MSI	$53,027	0.13%	1.23%	11.00%	0.0016%	0.0146%
M&T Bank Corp	MTB	n/a	N/A	3.77%	N/A	N/A	N/A
Match Group Inc	MTCH	$10,432	0.03%	0.00%	13.50%	0.0000%	0.0035%
Mettler-Toledo International Inc	MTD	$25,960	0.07%	0.00%	11.00%	0.0000%	0.0072%
Micron Technology Inc	MU	$94,660	0.24%	0.54%	22.00%	0.0013%	0.0522%
Norwegian Cruise Line Holdings Ltd	NCLH	n/a	N/A	0.00%	N/A	N/A	N/A
Nasdaq Inc	NDAQ	$33,331	0.08%	1.52%	7.00%	0.0013%	0.0059%
Nordson Corp	NDSN	$14,352	0.04%	1.08%	9.50%	0.0004%	0.0034%
NextEra Energy Inc	NEE	$118,650	0.30%	3.19%	9.50%	0.0095%	0.0283%
Newmont Corp	NEM	$39,772	0.10%	4.64%	8.00%	0.0046%	0.0080%
Netflix Inc	NFLX	$244,124	0.61%	0.00%	13.00%	0.0000%	0.0796%
NiSource Inc	NI	$10,736	0.03%	4.08%	9.50%	0.0011%	0.0026%
NIKE Inc	NKE	$123,585	0.31%	1.46%	17.00%	0.0045%	0.0527%
Northrop Grumman Corp	NOC	$67,030	0.17%	1.67%	8.50%	0.0028%	0.0143%
ServiceNow Inc	NOW	$156,907	0.39%	0.00%	61.00%	0.0000%	0.2401%
NRG Energy Inc	NRG	$11,975	0.03%	3.07%	-2.50%	0.0009%	-0.0008%
Norfolk Southern Corp	NSC	$53,089	0.13%	2.30%	8.50%	0.0031%	0.0113%
NetApp Inc	NTAP	$17,966	0.05%	2.29%	8.00%	0.0010%	0.0036%
Northern Trust Corp	NTRS	$16,336	0.04%	3.77%	3.00%	0.0015%	0.0012%
Nucor Corp	NUE	$45,955	0.12%	1.16%	2.00%	0.0013%	0.0023%
NVIDIA Corp	NVDA	$1,519,717	3.81%	0.03%	40.00%	0.0010%	1.5248%
NVR Inc	NVR	$22,606	0.06%	0.00%	3.50%	0.0000%	0.0020%
News Corp	NWS	n/a	N/A	0.78%	N/A	N/A	N/A
News Corp	NWSA	$9,380	0.02%	0.81%	19.00%	0.0002%	0.0045%
NXP Semiconductors NV	NXPI	$54,277	0.14%	1.93%	8.50%	0.0026%	0.0116%
Realty Income Corp	O	$45,241	0.11%	5.66%	5.50%	0.0064%	0.0062%

		[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Market Capitalization Excluding No Growth Rate ($ mill)	Weight in Index	Dividend Yield	Long-Term Growth Est.	Weighted Dividend Yield	Weighted Long-Term Growth Rate
Old Dominion Freight Line Inc	ODFL	$42,666	0.11%	0.53%	9.00%	0.0006%	0.0096%
ONEOK Inc	OKE	$39,759	0.10%	5.80%	12.00%	0.0058%	0.0120%
Omnicom Group Inc	OMC	$17,889	0.04%	3.10%	7.00%	0.0014%	0.0031%
ON Semiconductor Corp	ON	$30,636	0.08%	0.00%	14.50%	0.0000%	0.0111%
Oracle Corp	ORCL	$307,055	0.77%	1.43%	10.00%	0.0110%	0.0770%
O'Reilly Automotive Inc	ORLY	$60,526	0.15%	0.00%	11.00%	0.0000%	0.0167%
Otis Worldwide Corp	OTIS	$36,195	0.09%	1.54%	11.50%	0.0014%	0.0104%
Occidental Petroleum Corp	OXY	$50,522	0.13%	1.25%	17.00%	0.0016%	0.0215%
Palo Alto Networks Inc	PANW	n/a	N/A	0.00%	N/A	N/A	N/A
Paramount Global	PARA	$8,910	0.02%	1.37%	-2.50%	0.0003%	-0.0006%
Paycom Software Inc	PAYC	$11,458	0.03%	0.79%	21.00%	0.0002%	0.0060%
Paychex Inc	PAYX	$43,801	0.11%	2.92%	10.00%	0.0032%	0.0110%
PACCAR Inc	PCAR	$52,534	0.13%	1.08%	5.00%	0.0014%	0.0066%
PG&E Corp	PCG	$35,992	0.09%	0.24%	8.50%	0.0002%	0.0077%
Healthpeak Properties Inc	PEAK	$10,121	0.03%	6.49%	14.50%	0.0016%	0.0037%
Public Service Enterprise Group Inc	PEG	$28,943	0.07%	3.93%	4.00%	0.0029%	0.0029%
PepsiCo Inc	PEP	$231,706	0.58%	3.00%	7.50%	0.0175%	0.0436%
Pfizer Inc	PFE	$152,905	0.38%	6.20%	2.00%	0.0238%	0.0077%
Principal Financial Group Inc	PFG	$18,858	0.05%	3.39%	5.50%	0.0016%	0.0026%
Procter & Gamble Co/The	PG	$369,754	0.93%	2.39%	6.00%	0.0222%	0.0556%
Progressive Corp/The	PGR	$104,330	0.26%	0.22%	12.00%	0.0006%	0.0314%
Parker-Hannifin Corp	PH	$59,677	0.15%	1.27%	12.50%	0.0019%	0.0187%
PulteGroup Inc	PHM	$22,543	0.06%	0.77%	8.50%	0.0004%	0.0048%
Packaging Corp of America	PKG	$14,867	0.04%	3.01%	9.00%	0.0011%	0.0034%
Prologis Inc	PLD	$117,058	0.29%	2.75%	2.50%	0.0081%	0.0073%
Philip Morris International Inc	PM	$141,036	0.35%	5.72%	5.00%	0.0202%	0.0177%
PNC Financial Services Group Inc/T	PNC	$60,182	0.15%	4.10%	6.50%	0.0062%	0.0098%
Pentair PLC	PNR	$12,095	0.03%	1.26%	12.00%	0.0004%	0.0036%
Pinnacle West Capital Corp	PNW	$7,807	0.02%	5.11%	2.50%	0.0010%	0.0005%
Insulet Corp	PODD	n/a	N/A	0.00%	N/A	N/A	N/A
Pool Corp	POOL	$14,360	0.04%	1.19%	14.00%	0.0004%	0.0050%
PPG Industries Inc	PPG	$33,257	0.08%	1.84%	3.00%	0.0015%	0.0025%
PPL Corp	PPL	$19,313	0.05%	3.66%	8.00%	0.0018%	0.0039%
Prudential Financial Inc	PRU	$37,880	0.10%	4.77%	3.00%	0.0045%	0.0029%
Public Storage	PSA	$49,793	0.12%	4.24%	7.50%	0.0053%	0.0094%
Phillips 66	PSX	$63,490	0.16%	2.91%	15.50%	0.0046%	0.0247%
PTC Inc	PTC	$21,576	0.05%	0.00%	29.00%	0.0000%	0.0157%
Quanta Services Inc	PWR	$28,193	0.07%	0.19%	15.00%	0.0001%	0.0106%
Pioneer Natural Resources Co	PXD	$53,694	0.13%	5.57%	8.50%	0.0075%	0.0114%
PayPal Holdings Inc	PYPL	$66,144	0.17%	0.00%	12.00%	0.0000%	0.0199%
QUALCOMM Inc	QCOM	$165,737	0.42%	2.15%	5.50%	0.0090%	0.0229%
Qorvo Inc	QRVO	$9,709	0.02%	0.00%	14.50%	0.0000%	0.0035%
Royal Caribbean Cruises Ltd	RCL	n/a	N/A	0.00%	N/A	N/A	N/A
Regency Centers Corp	REG	$11,567	0.03%	4.28%	15.50%	0.0012%	0.0045%
Regeneron Pharmaceuticals Inc	REGN	n/a	N/A	0.00%	N/A	N/A	N/A
Regions Financial Corp	RF	$17,364	0.04%	5.14%	9.00%	0.0022%	0.0039%
Robert Half Inc	RHI	$8,423	0.02%	2.41%	7.00%	0.0005%	0.0015%
Raymond James Financial Inc	RJF	$22,995	0.06%	1.63%	12.50%	0.0009%	0.0072%
Ralph Lauren Corp	RL	$5,711	0.01%	2.09%	13.00%	0.0003%	0.0019%
ResMed Inc	RMD	$27,976	0.07%	1.01%	9.50%	0.0007%	0.0067%
Rockwell Automation Inc	ROK	$29,024	0.07%	1.97%	9.50%	0.0014%	0.0069%
Rollins Inc	ROL	$20,964	0.05%	1.39%	10.50%	0.0007%	0.0055%
Roper Technologies Inc	ROP	$57,363	0.14%	0.56%	8.50%	0.0008%	0.0122%
Ross Stores Inc	ROST	$47,228	0.12%	0.96%	14.00%	0.0011%	0.0166%
Republic Services Inc	RSG	$53,841	0.14%	1.25%	12.50%	0.0017%	0.0169%
RTX Corp	RTX	$131,022	0.33%	2.59%	15.00%	0.0085%	0.0493%
Revvity Inc	RVTY	$13,227	0.03%	0.26%	-3.50%	0.0001%	-0.0012%
SBA Communications Corp	SBAC	$24,152	0.06%	1.52%	22.00%	0.0009%	0.0133%
Starbucks Corp	SBUX	$105,329	0.26%	2.45%	16.00%	0.0065%	0.0423%
Charles Schwab Corp/The	SCHW	$111,474	0.28%	1.59%	10.00%	0.0044%	0.0280%
Sherwin-Williams Co/The	SHW	$77,911	0.20%	0.80%	7.00%	0.0016%	0.0137%
J M Smucker Co/The	SJM	$13,963	0.04%	3.22%	5.50%	0.0011%	0.0019%
Schlumberger NV	SLB	$69,514	0.17%	2.26%	26.00%	0.0039%	0.0453%
Snap-on Inc	SNA	$15,303	0.04%	2.57%	7.50%	0.0010%	0.0029%
Synopsys Inc	SNPS	$81,347	0.20%	0.00%	12.50%	0.0000%	0.0255%
Southern Co/The	SO	$75,882	0.19%	4.03%	6.50%	0.0077%	0.0124%
Simon Property Group Inc	SPG	$45,221	0.11%	5.48%	3.50%	0.0062%	0.0040%
S&P Global Inc	SPGI	$142,037	0.36%	0.81%	7.50%	0.0029%	0.0267%
Sempra	SRE	$45,035	0.11%	3.33%	6.50%	0.0038%	0.0073%
STERIS PLC	STE	$21,632	0.05%	0.95%	10.00%	0.0005%	0.0054%
Steel Dynamics Inc	STLD	$19,530	0.05%	1.41%	2.00%	0.0007%	0.0010%
State Street Corp	STT	n/a	N/A	3.74%	N/A	N/A	N/A
Seagate Technology Holdings PLC	STX	$17,951	0.05%	3.27%	15.00%	0.0015%	0.0068%
Constellation Brands Inc	STZ	$44,800	0.11%	1.45%	6.50%	0.0016%	0.0073%
Stanley Black & Decker Inc	SWK	$14,304	0.04%	3.47%	3.50%	0.0012%	0.0013%
Skyworks Solutions Inc	SWKS	n/a	N/A	2.60%	N/A	N/A	N/A
Synchrony Financial	SYF	$15,816	0.04%	2.57%	47.00%	0.0010%	0.0186%
Stryker Corp	SYK	$127,447	0.32%	0.95%	8.50%	0.0030%	0.0272%
Sysco Corp	SYY	$40,289	0.10%	2.47%	16.00%	0.0025%	0.0162%
AT&T Inc	T	$126,484	0.32%	6.27%	1.50%	0.0199%	0.0048%
Molson Coors Beverage Co	TAP	$12,417	0.03%	2.65%	42.00%	0.0008%	0.0131%
TransDigm Group Inc	TDG	$60,746	0.15%	0.00%	33.00%	0.0000%	0.0503%
Teledyne Technologies Inc	TDY	$19,746	0.05%	0.00%	9.50%	0.0000%	0.0047%
Bio-Techne Corp	TECH	$11,121	0.03%	0.46%	13.00%	0.0001%	0.0036%
TE Connectivity Ltd	TEL	$43,908	0.11%	1.66%	10.50%	0.0018%	0.0116%
Teradyne Inc	TER	$14,767	0.04%	0.50%	12.50%	0.0002%	0.0046%
Truist Financial Corp	TFC	$49,429	0.12%	5.61%	6.00%	0.0070%	0.0074%
Teleflex Inc	TFX	$11,411	0.03%	0.56%	10.00%	0.0002%	0.0029%
Target Corp	TGT	$64,208	0.16%	3.16%	11.00%	0.0051%	0.0177%
TJX Cos Inc/The	TJX	$108,167	0.27%	1.40%	17.00%	0.0038%	0.0461%
Thermo Fisher Scientific Inc	TMO	$208,247	0.52%	0.26%	9.50%	0.0014%	0.0496%

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate ($ mill)	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
T-Mobile US Inc	TMUS	$192,800	0.48%	1.61%	20.00%	0.0078%	0.0967%
Tapestry Inc	TPR	$8,890	0.02%	3.61%	16.50%	0.0008%	0.0037%
Targa Resources Corp	TRGP	n/a	N/A	2.35%	N/A	N/A	N/A
Trimble Inc	TRMB	$12,652	0.03%	0.00%	5.50%	0.0000%	0.0017%
T Rowe Price Group Inc	TROW	$24,235	0.06%	4.57%	1.50%	0.0028%	0.0009%
Travelers Cos Inc/The	TRV	$48,232	0.12%	1.89%	7.50%	0.0023%	0.0091%
Tractor Supply Co	TSCO	$24,282	0.06%	1.83%	11.50%	0.0011%	0.0070%
Tesla Inc	TSLA	$596,479	1.50%	0.00%	28.00%	0.0000%	0.4189%
Tyson Foods Inc	TSN	$15,681	0.04%	3.58%	6.00%	0.0014%	0.0024%
Trane Technologies PLC	TT	$57,356	0.14%	1.19%	14.50%	0.0017%	0.0209%
Take-Two Interactive Software Inc	TTWO	n/a	N/A	0.00%	N/A	N/A	N/A
Texas Instruments Inc	TXN	$145,549	0.37%	3.25%	3.50%	0.0119%	0.0128%
Textron Inc	TXT	$16,604	0.04%	0.09%	16.00%	0.0000%	0.0067%
Tyler Technologies Inc	TYL	$17,808	0.04%	0.00%	10.00%	0.0000%	0.0045%
United Airlines Holdings Inc	UAL	n/a	N/A	0.00%	N/A	N/A	N/A
Uber Technologies Inc	UBER	n/a	N/A	0.00%	N/A	N/A	N/A
UDR Inc	UDR	$11,848	0.03%	4.66%	17.00%	0.0014%	0.0051%
Universal Health Services Inc	UHS	$9,689	0.02%	0.50%	6.00%	0.0001%	0.0015%
Ulta Beauty Inc	ULTA	$24,381	0.06%	0.00%	13.50%	0.0000%	0.0083%
UnitedHealth Group Inc	UNH	$473,321	1.19%	1.47%	12.00%	0.0174%	0.1425%
Union Pacific Corp	UNP	$148,699	0.37%	2.13%	7.50%	0.0080%	0.0280%
United Parcel Service Inc	UPS	$102,630	0.26%	4.59%	5.50%	0.0118%	0.0142%
United Rentals Inc	URI	$42,022	0.11%	1.04%	17.00%	0.0011%	0.0179%
US Bancorp	USB	$64,719	0.16%	4.72%	4.00%	0.0077%	0.0065%
Visa Inc	V	$432,185	1.08%	0.76%	13.50%	0.0083%	0.1463%
VF Corp	VFC	$6,401	0.02%	2.19%	9.00%	0.0004%	0.0014%
VICI Properties Inc	VICI	$31,160	0.08%	5.51%	8.00%	0.0043%	0.0063%
Valero Energy Corp	VLO	$47,289	0.12%	3.08%	9.50%	0.0037%	0.0113%
Veralto Corp	VLTO	n/a	N/A	0.47%	N/A	N/A	N/A
Vulcan Materials Co	VMC	$30,031	0.08%	0.76%	9.50%	0.0006%	0.0072%
Verisk Analytics Inc	VRSK	$35,019	0.09%	0.56%	9.00%	0.0005%	0.0079%
VeriSign Inc	VRSN	$20,306	0.05%	0.00%	13.00%	0.0000%	0.0066%
Vertex Pharmaceuticals Inc	VRTX	$111,675	0.28%	0.00%	10.00%	0.0000%	0.0280%
Ventas Inc	VTR	$18,666	0.05%	3.88%	23.00%	0.0018%	0.0108%
Viatris Inc	VTRS	n/a	N/A	4.08%	N/A	N/A	N/A
Verizon Communications Inc	VZ	$178,039	0.45%	6.28%	1.50%	0.0280%	0.0067%
Westinghouse Air Brake Technologie	WAB	$23,572	0.06%	0.52%	10.50%	0.0003%	0.0062%
Waters Corp	WAT	$18,785	0.05%	0.00%	10.00%	0.0000%	0.0047%
Walgreens Boots Alliance Inc	WBA	$19,464	0.05%	4.43%	-1.50%	0.0022%	-0.0007%
Warner Bros Discovery Inc	WBD	n/a	N/A	0.00%	N/A	N/A	N/A
Western Digital Corp	WDC	$18,563	0.05%	0.00%	13.00%	0.0000%	0.0061%
WEC Energy Group Inc	WEC	$25,475	0.06%	4.14%	6.00%	0.0026%	0.0038%
Welltower Inc	WELL	$48,108	0.12%	2.82%	12.00%	0.0034%	0.0145%
Wells Fargo & Co	WFC	$180,593	0.45%	2.79%	10.50%	0.0126%	0.0476%
Whirlpool Corp	WHR	$6,024	0.02%	6.39%	-1.00%	0.0010%	-0.0002%
Waste Management Inc	WM	$74,767	0.19%	1.51%	6.50%	0.0028%	0.0122%
Williams Cos Inc/The	WMB	$42,164	0.11%	5.48%	10.50%	0.0058%	0.0111%
Walmart Inc	WMT	$444,892	1.12%	1.38%	6.50%	0.0154%	0.0725%
W R Berkley Corp	WRB	$21,006	0.05%	0.54%	15.00%	0.0003%	0.0079%
Westrock Co	WRK	$10,327	0.03%	3.01%	10.00%	0.0008%	0.0026%
West Pharmaceutical Services Inc	WST	$27,600	0.07%	0.21%	17.00%	0.0001%	0.0118%
Willis Towers Watson PLC	WTW	$25,433	0.06%	1.36%	9.00%	0.0009%	0.0057%
Weyerhaeuser Co	WY	$23,922	0.06%	0.43%	-2.00%	0.0003%	-0.0012%
Wynn Resorts Ltd	WYNN	$10,665	0.03%	1.06%	27.00%	0.0003%	0.0072%
Xcel Energy Inc	XEL	$33,037	0.08%	3.47%	6.00%	0.0029%	0.0050%
Exxon Mobil Corp	XOM	$411,871	1.03%	3.70%	7.00%	0.0382%	0.0723%
DENTSPLY SIRONA Inc	XRAY	$7,362	0.02%	1.61%	12.00%	0.0003%	0.0022%
Xylem Inc/NY	XYL	$27,107	0.07%	1.17%	15.50%	0.0008%	0.0105%
Yum! Brands Inc	YUM	$36,297	0.09%	2.07%	11.50%	0.0019%	0.0105%
Zimmer Biomet Holdings Inc	ZBH	$26,248	0.07%	0.76%	6.50%	0.0005%	0.0043%
Zebra Technologies Corp	ZBRA	$12,303	0.03%	0.00%	-2.50%	0.0000%	-0.0008%
Zions Bancorp NA	ZION	$6,208	0.02%	3.91%	2.50%	0.0006%	0.0004%
Zoetis Inc	ZTS	$86,226	0.22%	0.92%	9.00%	0.0020%	0.0195%
		$39,866,827					

[4] Source: Bloomberg Professional as of January 31, 2024
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Bloomberg Professional as of January 31, 2024
[7] Source: Value Line as of January 31, 2024
[8] Equals [5] x [6]
[9] Equals [5] x [7]

Ex Ante Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using Long-Term Historical Market Return

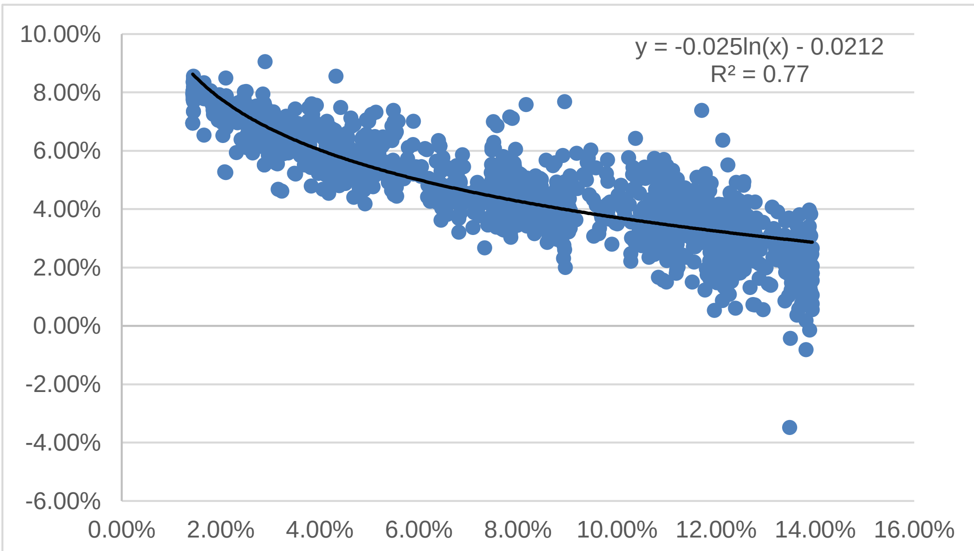
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Company	Ticker	Current 30-Year Treasury Yield	Bloomberg Beta Coefficient	Value Line Beta Coefficient	Average Beta Coefficient	Long-Term Average Historical Market Return (1926-2022)	Market Risk Premium	Traditional CAPM	Empirical CAPM
Alliant Energy Corporation	LNT	4.19%	0.88	0.90	0.89	12.02%	7.83%	11.14%	11.36%
Ameren Corporation	AEE	4.19%	0.84	0.90	0.87	12.02%	7.83%	11.00%	11.25%
American Electric Power Company, Inc.	AEP	4.19%	0.84	0.80	0.82	12.02%	7.83%	10.62%	10.97%
Avista Corporation	AVA	4.19%	0.84	0.95	0.90	12.02%	7.83%	11.20%	11.40%
CMS Energy Corporation	CMS	4.19%	0.84	0.85	0.84	12.02%	7.83%	10.80%	11.10%
DTE Energy Company	DTE	4.19%	0.93	1.00	0.97	12.02%	7.83%	11.75%	11.82%
Duke Energy Corporation	DUK	4.19%	0.83	0.85	0.84	12.02%	7.83%	10.76%	11.07%
Edison International	EIX	4.19%	0.98	1.00	0.99	12.02%	7.83%	11.93%	11.96%
Entergy Corporation	ETR	4.19%	0.98	0.95	0.96	12.02%	7.83%	11.73%	11.80%
Evergy, Inc.	EVRG	4.19%	0.89	0.95	0.92	12.02%	7.83%	11.41%	11.56%
IDACORP, Inc.	IDA	4.19%	0.87	0.85	0.86	12.02%	7.83%	10.92%	11.19%
NextEra Energy, Inc.	NEE	4.19%	0.91	0.95	0.93	12.02%	7.83%	11.46%	11.60%
NorthWestern Energy Group, Inc.	NWE	4.19%	1.00	0.95	0.97	12.02%	7.83%	11.82%	11.87%
OGE Energy Corporation	OGE	4.19%	1.02	1.05	1.04	12.02%	7.83%	12.30%	12.23%
Pinnacle West Capital Corporation	PNW	4.19%	0.94	0.95	0.95	12.02%	7.83%	11.59%	11.69%
Portland General Electric Company	POR	4.19%	0.88	0.90	0.89	12.02%	7.83%	11.17%	11.38%
Southern Company	SO	4.19%	0.90	0.90	0.90	12.02%	7.83%	11.21%	11.42%
Xcel Energy Inc.	XEL	4.19%	0.84	0.85	0.84	12.02%	7.83%	10.79%	11.10%
							Mean:	11.31%	11.49%
							Median:	11.21%	11.41%
							Average of the Mean and Median:	11.26%	11.45%

		[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Company	Ticker	Projected 30-Year Treasury Yield	Bloomberg Beta Coefficient	Value Line Beta Coefficient	Average Beta Coefficient	Long-Term Average Historical Market Return (1926-2022)	Market Risk Premium	Traditional CAPM	Empirical CAPM
Alliant Energy Corporation	LNT	4.14%	0.88	0.90	0.89	12.02%	7.87%	11.14%	11.36%
Ameren Corporation	AEE	4.14%	0.84	0.90	0.87	12.02%	7.87%	10.99%	11.25%
American Electric Power Company, Inc.	AEP	4.14%	0.84	0.80	0.82	12.02%	7.87%	10.61%	10.96%
Avista Corporation	AVA	4.14%	0.84	0.95	0.90	12.02%	7.87%	11.19%	11.40%
CMS Energy Corporation	CMS	4.14%	0.84	0.85	0.84	12.02%	7.87%	10.79%	11.10%
DTE Energy Company	DTE	4.14%	0.93	1.00	0.97	12.02%	7.87%	11.75%	11.82%
Duke Energy Corporation	DUK	4.14%	0.83	0.85	0.84	12.02%	7.87%	10.75%	11.07%
Edison International	EIX	4.14%	0.98	1.00	0.99	12.02%	7.87%	11.93%	11.95%
Entergy Corporation	ETR	4.14%	0.98	0.95	0.96	12.02%	7.87%	11.73%	11.80%
Evergy, Inc.	EVRG	4.14%	0.89	0.95	0.92	12.02%	7.87%	11.40%	11.56%
IDACORP, Inc.	IDA	4.14%	0.87	0.85	0.86	12.02%	7.87%	10.91%	11.19%
NextEra Energy, Inc.	NEE	4.14%	0.91	0.95	0.93	12.02%	7.87%	11.46%	11.60%
NorthWestern Energy Group, Inc.	NWE	4.14%	1.00	0.95	0.97	12.02%	7.87%	11.82%	11.87%
OGE Energy Corporation	OGE	4.14%	1.02	1.05	1.04	12.02%	7.87%	12.30%	12.23%
Pinnacle West Capital Corporation	PNW	4.14%	0.94	0.95	0.95	12.02%	7.87%	11.58%	11.69%
Portland General Electric Company	POR	4.14%	0.88	0.90	0.89	12.02%	7.87%	11.17%	11.38%
Southern Company	SO	4.14%	0.90	0.90	0.90	12.02%	7.87%	11.21%	11.41%
Xcel Energy Inc.	XEL	4.14%	0.84	0.85	0.84	12.02%	7.87%	10.79%	11.09%
							Mean:	11.31%	11.48%
							Median:	11.20%	11.41%
							Average of the Mean and Median:	11.25%	11.44%

[1] Source: Bloomberg Professional Service; 30-day average
[2] Source: Bloomberg Professional Service
[3] Source: Value Line
[4] Equals Average of Col. [2] and Col. [3]
[5] Kroll, 2023 SBBI Yearbook Appendix A-1.
[6] Equals Col. [5] - Col. [1]
[7] Equals Col. [1] + (Col. [4] x Col. [6])
[8] Equals Col. [1] + (0.75 x Col. [4] x Col. [6]) + (0.25 x Col. [6])
[9] Source: Blue Chip Financial Forecasts, Vol. 43, No. 2, February 1, 2024, at 2; Vol. 42, No. 12, December 1, 2023, at 14
[10] See Note [2]
[11] See Note [3]
[12] Equals Average of Col. [10] and Col. [11]
[13] See Note [5]
[14] Equals Col. [13] - Col. [9]
[15] Equals Col. [9] + (Col. [12] x Col. [14])
[16] Equals Col. [9] + (0.75 x Col. [12] x Col. [14]) + (0.25 x Col. [14])

Bond Yield Plus Risk Premium

[1] Constant	[2] Slope	[3] 30-Year Treasury Yield	[4] Risk Premium	[5] Return on Equity
-2.12%	-2.53%			
Current 30-Year Treasury		4.19%	5.91%	10.10%
Projected 30-Year Treasury		4.14%	5.94%	10.08%



Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Sources: Current = Bloomberg Professional,
Projected = Average of near-term and long-term projected 30-year Treasury yield from
Blue Chip Financial Forecasts, Vol. 43, No. 2, February 1, 2024, at 2; Vol. 42, No. 12, December 1, 2023, at 14
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]
[6] Source: S&P Capital IQ
[7] Source: S&P Capital IQ
[8] Source: Bloomberg Professional, equals 200-trading day average (i.e. lag period)
[9] Equals [9] - [10]

Bond Yield Plus Risk Premium

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/1/1980	14.50%	9.36%	5.14%
1/7/1980	14.39%	9.38%	5.01%
1/9/1980	15.00%	9.40%	5.60%
1/14/1980	15.17%	9.42%	5.75%
1/17/1980	13.93%	9.44%	4.49%
1/23/1980	15.50%	9.47%	6.03%
1/30/1980	13.86%	9.52%	4.34%
1/31/1980	12.61%	9.53%	3.08%
2/6/1980	13.71%	9.58%	4.13%
2/13/1980	12.80%	9.63%	3.17%
2/14/1980	13.00%	9.65%	3.35%
2/19/1980	13.50%	9.68%	3.82%
2/27/1980	13.75%	9.78%	3.97%
2/29/1980	13.75%	9.81%	3.94%
2/29/1980	14.00%	9.81%	4.19%
2/29/1980	14.77%	9.81%	4.96%
3/7/1980	12.70%	9.89%	2.81%
3/14/1980	13.50%	9.97%	3.53%
3/26/1980	14.16%	10.10%	4.06%
3/27/1980	14.24%	10.12%	4.12%
3/28/1980	14.50%	10.13%	4.37%
4/11/1980	12.75%	10.27%	2.48%
4/14/1980	13.85%	10.29%	3.56%
4/16/1980	15.50%	10.31%	5.19%
4/22/1980	13.25%	10.35%	2.90%
4/22/1980	13.90%	10.35%	3.55%
4/24/1980	16.80%	10.38%	6.43%
4/29/1980	15.50%	10.41%	5.09%
5/6/1980	13.70%	10.45%	3.25%
5/7/1980	15.00%	10.45%	4.55%
5/8/1980	13.75%	10.46%	3.29%
5/9/1980	14.35%	10.47%	3.88%
5/13/1980	13.60%	10.48%	3.12%
5/15/1980	13.25%	10.49%	2.76%
5/19/1980	13.75%	10.51%	3.24%
5/27/1980	13.62%	10.54%	3.08%
5/27/1980	14.60%	10.54%	4.06%
5/29/1980	16.00%	10.56%	5.44%
5/30/1980	13.80%	10.56%	3.24%
6/2/1980	15.63%	10.57%	5.06%
6/9/1980	15.90%	10.60%	5.30%
6/10/1980	13.78%	10.60%	3.18%
6/12/1980	14.25%	10.61%	3.64%
6/19/1980	13.40%	10.62%	2.78%
6/30/1980	13.00%	10.65%	2.35%
6/30/1980	13.40%	10.65%	2.75%
7/9/1980	14.75%	10.67%	4.08%
7/10/1980	15.00%	10.68%	4.32%
7/15/1980	15.80%	10.70%	5.10%
7/18/1980	13.80%	10.71%	3.09%
7/22/1980	14.10%	10.72%	3.38%
7/24/1980	15.00%	10.73%	4.27%
7/25/1980	13.48%	10.73%	2.75%
7/31/1980	14.58%	10.75%	3.83%
8/8/1980	13.50%	10.78%	2.72%
8/8/1980	14.00%	10.78%	3.22%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
8/8/1980	15.45%	10.78%	4.67%
8/11/1980	14.85%	10.78%	4.07%
8/14/1980	14.00%	10.79%	3.21%
8/14/1980	16.25%	10.79%	5.46%
8/25/1980	13.75%	10.82%	2.93%
8/27/1980	13.80%	10.83%	2.97%
8/29/1980	12.50%	10.84%	1.66%
9/15/1980	13.50%	10.88%	2.62%
9/15/1980	15.80%	10.88%	4.92%
9/15/1980	13.93%	10.88%	3.05%
9/24/1980	12.50%	10.93%	1.57%
9/24/1980	15.00%	10.93%	4.07%
9/26/1980	13.75%	10.94%	2.81%
9/30/1980	14.10%	10.96%	3.14%
9/30/1980	14.20%	10.96%	3.24%
10/1/1980	13.90%	10.97%	2.93%
10/3/1980	15.50%	10.98%	4.52%
10/7/1980	12.50%	10.99%	1.51%
10/9/1980	13.25%	11.00%	2.25%
10/9/1980	14.50%	11.00%	3.50%
10/9/1980	14.50%	11.00%	3.50%
10/16/1980	16.10%	11.02%	5.08%
10/17/1980	14.50%	11.03%	3.47%
10/31/1980	13.75%	11.11%	2.64%
10/31/1980	14.25%	11.11%	3.14%
11/4/1980	15.00%	11.12%	3.88%
11/5/1980	14.00%	11.12%	2.88%
11/5/1980	13.75%	11.12%	2.63%
11/8/1980	13.75%	11.14%	2.61%
11/10/1980	14.85%	11.15%	3.70%
11/17/1980	14.00%	11.18%	2.82%
11/18/1980	14.00%	11.19%	2.81%
11/19/1980	13.00%	11.19%	1.81%
11/24/1980	14.00%	11.21%	2.79%
11/26/1980	14.00%	11.21%	2.79%
12/8/1980	14.15%	11.22%	2.93%
12/8/1980	15.10%	11.22%	3.88%
12/9/1980	15.35%	11.22%	4.13%
12/12/1980	15.45%	11.23%	4.22%
12/17/1980	13.25%	11.23%	2.02%
12/18/1980	15.80%	11.23%	4.57%
12/19/1980	14.50%	11.23%	3.27%
12/19/1980	14.64%	11.23%	3.41%
12/22/1980	13.45%	11.23%	2.22%
12/22/1980	15.00%	11.23%	3.77%
12/30/1980	14.95%	11.22%	3.73%
12/30/1980	14.50%	11.22%	3.28%
12/31/1980	13.39%	11.22%	2.17%
1/2/1981	15.25%	11.22%	4.03%
1/7/1981	14.30%	11.21%	3.09%
1/19/1981	15.25%	11.20%	4.05%
1/23/1981	14.40%	11.20%	3.20%
1/23/1981	13.10%	11.20%	1.90%
1/26/1981	15.25%	11.20%	4.05%
1/27/1981	15.00%	11.21%	3.79%
1/31/1981	13.47%	11.22%	2.25%
2/3/1981	15.25%	11.23%	4.02%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
2/5/1981	15.75%	11.25%	4.50%
2/11/1981	15.60%	11.28%	4.32%
2/20/1981	15.25%	11.33%	3.92%
3/11/1981	15.40%	11.49%	3.91%
3/12/1981	14.51%	11.50%	3.01%
3/12/1981	16.00%	11.50%	4.50%
3/13/1981	13.02%	11.52%	1.50%
3/18/1981	16.19%	11.55%	4.64%
3/19/1981	13.75%	11.56%	2.19%
3/23/1981	14.30%	11.58%	2.72%
3/25/1981	15.30%	11.60%	3.70%
4/1/1981	14.53%	11.68%	2.85%
4/3/1981	19.10%	11.71%	7.39%
4/9/1981	15.00%	11.78%	3.22%
4/9/1981	15.30%	11.78%	3.52%
4/9/1981	17.00%	11.78%	5.22%
4/9/1981	16.50%	11.78%	4.72%
4/10/1981	13.75%	11.80%	1.95%
4/13/1981	13.57%	11.82%	1.75%
4/15/1981	15.30%	11.85%	3.45%
4/16/1981	13.50%	11.87%	1.63%
4/17/1981	14.10%	11.87%	2.23%
4/21/1981	14.00%	11.90%	2.10%
4/21/1981	16.80%	11.90%	4.90%
4/24/1981	16.00%	11.95%	4.05%
4/27/1981	12.50%	11.97%	0.53%
4/27/1981	13.61%	11.97%	1.64%
4/29/1981	13.65%	12.00%	1.65%
4/30/1981	13.50%	12.02%	1.48%
5/4/1981	16.22%	12.05%	4.17%
5/5/1981	14.40%	12.07%	2.33%
5/7/1981	16.25%	12.11%	4.14%
5/7/1981	16.27%	12.11%	4.16%
5/8/1981	13.00%	12.13%	0.87%
5/8/1981	16.00%	12.13%	3.87%
5/12/1981	13.50%	12.16%	1.34%
5/15/1981	15.75%	12.22%	3.53%
5/18/1981	14.88%	12.23%	2.65%
5/20/1981	16.00%	12.26%	3.74%
5/21/1981	14.00%	12.27%	1.73%
5/26/1981	14.90%	12.30%	2.60%
5/27/1981	15.00%	12.31%	2.69%
5/29/1981	15.50%	12.34%	3.16%
6/1/1981	16.50%	12.35%	4.15%
6/3/1981	14.67%	12.37%	2.30%
6/5/1981	13.00%	12.39%	0.61%
6/10/1981	16.75%	12.42%	4.33%
6/17/1981	14.40%	12.46%	1.94%
6/18/1981	16.33%	12.47%	3.86%
6/25/1981	14.75%	12.51%	2.24%
6/26/1981	16.00%	12.52%	3.48%
6/30/1981	15.25%	12.54%	2.71%
7/1/1981	15.50%	12.56%	2.94%
7/1/1981	17.50%	12.56%	4.94%
7/10/1981	16.00%	12.62%	3.38%
7/14/1981	16.90%	12.64%	4.26%
7/15/1981	16.00%	12.65%	3.35%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
7/17/1981	15.00%	12.67%	2.33%
7/20/1981	15.00%	12.68%	2.32%
7/21/1981	14.00%	12.69%	1.31%
7/28/1981	13.48%	12.74%	0.74%
7/31/1981	13.50%	12.78%	0.72%
7/31/1981	15.00%	12.78%	2.22%
7/31/1981	16.00%	12.78%	3.22%
8/5/1981	15.71%	12.83%	2.88%
8/10/1981	14.50%	12.87%	1.63%
8/11/1981	15.00%	12.88%	2.12%
8/20/1981	13.50%	12.95%	0.55%
8/20/1981	16.50%	12.95%	3.55%
8/24/1981	15.00%	12.97%	2.03%
8/28/1981	15.00%	13.01%	1.99%
9/3/1981	14.50%	13.05%	1.45%
9/10/1981	14.50%	13.11%	1.39%
9/11/1981	16.00%	13.12%	2.88%
9/16/1981	16.00%	13.15%	2.85%
9/17/1981	16.50%	13.16%	3.34%
9/23/1981	15.85%	13.20%	2.65%
9/28/1981	15.50%	13.23%	2.27%
10/9/1981	15.75%	13.33%	2.42%
10/15/1981	16.25%	13.37%	2.88%
10/16/1981	15.50%	13.38%	2.12%
10/16/1981	16.50%	13.38%	3.12%
10/19/1981	14.25%	13.39%	0.86%
10/20/1981	17.00%	13.41%	3.59%
10/20/1981	15.25%	13.41%	1.84%
10/23/1981	16.00%	13.45%	2.55%
10/27/1981	10.00%	13.48%	-3.48%
10/29/1981	16.50%	13.51%	2.99%
10/29/1981	14.75%	13.51%	1.24%
11/3/1981	15.17%	13.53%	1.64%
11/5/1981	16.60%	13.55%	3.05%
11/6/1981	15.17%	13.56%	1.61%
11/24/1981	15.50%	13.61%	1.89%
11/25/1981	15.35%	13.61%	1.74%
11/25/1981	15.25%	13.61%	1.64%
11/25/1981	16.10%	13.61%	2.49%
11/25/1981	16.10%	13.61%	2.49%
12/1/1981	16.00%	13.61%	2.39%
12/1/1981	16.50%	13.61%	2.89%
12/1/1981	16.49%	13.61%	2.88%
12/1/1981	15.70%	13.61%	2.09%
12/4/1981	16.00%	13.61%	2.39%
12/11/1981	16.25%	13.63%	2.62%
12/14/1981	14.00%	13.63%	0.37%
12/15/1981	15.81%	13.63%	2.18%
12/15/1981	16.00%	13.63%	2.37%
12/16/1981	15.25%	13.63%	1.62%
12/17/1981	16.50%	13.63%	2.87%
12/18/1981	15.45%	13.63%	1.82%
12/30/1981	14.25%	13.67%	0.58%
12/30/1981	16.25%	13.67%	2.58%
12/30/1981	16.00%	13.67%	2.33%
12/31/1981	16.15%	13.67%	2.48%
1/4/1982	15.50%	13.67%	1.83%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/11/1982	17.00%	13.72%	3.28%
1/11/1982	14.50%	13.72%	0.78%
1/13/1982	14.75%	13.74%	1.01%
1/14/1982	15.75%	13.75%	2.00%
1/15/1982	16.50%	13.76%	2.74%
1/15/1982	15.00%	13.76%	1.24%
1/22/1982	16.25%	13.79%	2.46%
1/27/1982	16.84%	13.81%	3.03%
1/28/1982	13.00%	13.81%	-0.81%
1/29/1982	15.50%	13.82%	1.68%
2/1/1982	15.85%	13.82%	2.03%
2/3/1982	16.44%	13.84%	2.60%
2/8/1982	15.50%	13.86%	1.64%
2/11/1982	16.00%	13.88%	2.12%
2/11/1982	16.20%	13.88%	2.32%
2/17/1982	15.00%	13.89%	1.11%
2/19/1982	15.17%	13.89%	1.28%
2/26/1982	15.25%	13.89%	1.36%
3/1/1982	15.03%	13.89%	1.14%
3/1/1982	16.00%	13.89%	2.11%
3/3/1982	15.00%	13.88%	1.12%
3/8/1982	17.10%	13.88%	3.22%
3/12/1982	16.25%	13.88%	2.37%
3/17/1982	17.30%	13.88%	3.42%
3/22/1982	15.10%	13.89%	1.21%
3/27/1982	15.40%	13.89%	1.51%
3/30/1982	15.50%	13.90%	1.60%
3/31/1982	17.00%	13.91%	3.09%
4/1/1982	14.70%	13.91%	0.79%
4/1/1982	16.50%	13.91%	2.59%
4/2/1982	15.50%	13.91%	1.59%
4/5/1982	15.50%	13.92%	1.58%
4/8/1982	16.40%	13.93%	2.47%
4/13/1982	14.50%	13.94%	0.56%
4/23/1982	15.75%	13.94%	1.81%
4/27/1982	15.00%	13.94%	1.06%
4/28/1982	15.75%	13.94%	1.81%
4/30/1982	14.70%	13.94%	0.76%
4/30/1982	15.50%	13.94%	1.56%
5/3/1982	16.60%	13.94%	2.66%
5/4/1982	16.00%	13.94%	2.06%
5/14/1982	15.50%	13.92%	1.58%
5/18/1982	15.42%	13.92%	1.50%
5/19/1982	14.69%	13.92%	0.77%
5/20/1982	15.10%	13.91%	1.19%
5/20/1982	15.50%	13.91%	1.59%
5/20/1982	15.00%	13.91%	1.09%
5/20/1982	16.30%	13.91%	2.39%
5/21/1982	17.75%	13.91%	3.84%
5/27/1982	15.00%	13.89%	1.11%
5/28/1982	17.00%	13.89%	3.11%
5/28/1982	15.50%	13.89%	1.61%
6/1/1982	13.75%	13.89%	-0.14%
6/1/1982	16.60%	13.89%	2.71%
6/9/1982	17.86%	13.88%	3.98%
6/14/1982	15.75%	13.88%	1.87%
6/15/1982	14.85%	13.88%	0.97%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
6/18/1982	15.50%	13.87%	1.63%
6/21/1982	14.90%	13.87%	1.03%
6/23/1982	16.00%	13.86%	2.14%
6/23/1982	16.17%	13.86%	2.31%
6/24/1982	14.85%	13.86%	0.99%
6/25/1982	14.70%	13.86%	0.84%
7/1/1982	16.00%	13.84%	2.16%
7/2/1982	15.62%	13.84%	1.78%
7/2/1982	17.00%	13.84%	3.16%
7/13/1982	16.80%	13.82%	2.98%
7/13/1982	14.00%	13.82%	0.18%
7/14/1982	15.76%	13.82%	1.94%
7/14/1982	16.02%	13.82%	2.20%
7/19/1982	16.50%	13.80%	2.70%
7/22/1982	17.00%	13.77%	3.23%
7/22/1982	14.50%	13.77%	0.73%
7/27/1982	16.75%	13.75%	3.00%
7/29/1982	16.50%	13.74%	2.76%
8/11/1982	17.50%	13.68%	3.82%
8/18/1982	17.07%	13.63%	3.44%
8/20/1982	15.73%	13.60%	2.13%
8/25/1982	16.00%	13.57%	2.43%
8/26/1982	15.50%	13.56%	1.94%
8/30/1982	15.00%	13.55%	1.45%
9/3/1982	16.20%	13.53%	2.67%
9/8/1982	15.00%	13.52%	1.48%
9/15/1982	16.25%	13.50%	2.75%
9/15/1982	13.08%	13.50%	-0.42%
9/16/1982	16.00%	13.50%	2.50%
9/17/1982	15.25%	13.50%	1.75%
9/23/1982	17.17%	13.47%	3.70%
9/24/1982	14.50%	13.46%	1.04%
9/27/1982	15.25%	13.46%	1.79%
10/1/1982	15.50%	13.42%	2.08%
10/15/1982	15.90%	13.32%	2.58%
10/22/1982	15.75%	13.24%	2.51%
10/22/1982	17.15%	13.24%	3.91%
10/29/1982	15.54%	13.16%	2.38%
11/1/1982	15.50%	13.15%	2.35%
11/3/1982	17.20%	13.13%	4.07%
11/4/1982	16.25%	13.11%	3.14%
11/5/1982	16.20%	13.09%	3.11%
11/9/1982	16.00%	13.05%	2.95%
11/23/1982	15.50%	12.89%	2.61%
11/23/1982	15.85%	12.89%	2.96%
11/30/1982	16.50%	12.81%	3.69%
12/1/1982	17.04%	12.79%	4.25%
12/6/1982	15.00%	12.73%	2.27%
12/6/1982	16.35%	12.73%	3.62%
12/10/1982	15.50%	12.66%	2.84%
12/13/1982	16.00%	12.65%	3.35%
12/14/1982	15.30%	12.63%	2.67%
12/14/1982	16.40%	12.63%	3.77%
12/20/1982	16.00%	12.57%	3.43%
12/21/1982	14.75%	12.56%	2.19%
12/21/1982	15.85%	12.56%	3.29%
12/22/1982	16.58%	12.54%	4.04%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/22/1982	16.75%	12.54%	4.21%
12/22/1982	16.25%	12.54%	3.71%
12/29/1982	14.90%	12.48%	2.42%
12/29/1982	16.25%	12.48%	3.77%
12/30/1982	16.35%	12.47%	3.88%
12/30/1982	16.00%	12.47%	3.53%
12/30/1982	16.77%	12.47%	4.30%
1/5/1983	17.33%	12.40%	4.93%
1/11/1983	15.90%	12.34%	3.56%
1/12/1983	15.50%	12.33%	3.17%
1/12/1983	14.63%	12.33%	2.30%
1/20/1983	17.75%	12.24%	5.51%
1/21/1983	15.00%	12.22%	2.78%
1/24/1983	15.50%	12.21%	3.29%
1/24/1983	14.50%	12.21%	2.29%
1/25/1983	15.85%	12.19%	3.66%
1/27/1983	16.14%	12.17%	3.97%
2/1/1983	18.50%	12.13%	6.37%
2/4/1983	14.00%	12.10%	1.90%
2/10/1983	15.00%	12.06%	2.94%
2/21/1983	15.50%	11.98%	3.52%
2/22/1983	15.50%	11.97%	3.53%
2/23/1983	16.00%	11.96%	4.04%
2/23/1983	15.10%	11.96%	3.14%
3/2/1983	15.25%	11.89%	3.36%
3/9/1983	15.20%	11.82%	3.38%
3/15/1983	13.00%	11.77%	1.23%
3/18/1983	15.25%	11.73%	3.52%
3/23/1983	15.40%	11.69%	3.71%
3/24/1983	15.00%	11.67%	3.33%
3/29/1983	15.50%	11.63%	3.87%
3/30/1983	16.71%	11.61%	5.10%
3/31/1983	15.00%	11.59%	3.41%
4/4/1983	15.20%	11.58%	3.62%
4/8/1983	15.50%	11.51%	3.99%
4/11/1983	14.81%	11.49%	3.32%
4/19/1983	14.50%	11.38%	3.12%
4/20/1983	16.00%	11.36%	4.64%
4/29/1983	16.00%	11.24%	4.76%
5/1/1983	14.50%	11.24%	3.26%
5/9/1983	15.50%	11.15%	4.35%
5/11/1983	16.46%	11.12%	5.34%
5/12/1983	14.14%	11.11%	3.03%
5/18/1983	15.00%	11.05%	3.95%
5/23/1983	14.90%	11.01%	3.89%
5/23/1983	15.50%	11.01%	4.49%
5/25/1983	15.50%	10.98%	4.52%
5/27/1983	15.00%	10.96%	4.04%
5/31/1983	14.00%	10.95%	3.05%
5/31/1983	15.50%	10.95%	4.55%
6/2/1983	14.50%	10.93%	3.57%
6/17/1983	15.03%	10.84%	4.19%
7/1/1983	14.90%	10.78%	4.12%
7/1/1983	14.80%	10.78%	4.02%
7/8/1983	16.25%	10.76%	5.49%
7/13/1983	13.20%	10.75%	2.45%
7/19/1983	15.00%	10.74%	4.26%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
7/19/1983	15.10%	10.74%	4.36%
7/25/1983	16.25%	10.73%	5.52%
7/28/1983	15.90%	10.74%	5.16%
8/3/1983	16.34%	10.75%	5.59%
8/3/1983	16.50%	10.75%	5.75%
8/19/1983	15.00%	10.80%	4.20%
8/22/1983	15.50%	10.80%	4.70%
8/22/1983	16.40%	10.80%	5.60%
8/31/1983	14.75%	10.84%	3.91%
9/7/1983	15.00%	10.86%	4.14%
9/14/1983	15.78%	10.89%	4.89%
9/16/1983	15.00%	10.90%	4.10%
9/19/1983	14.50%	10.91%	3.59%
9/20/1983	16.50%	10.91%	5.59%
9/28/1983	14.50%	10.94%	3.56%
9/29/1983	15.50%	10.95%	4.55%
9/30/1983	16.15%	10.95%	5.20%
9/30/1983	15.25%	10.95%	4.30%
10/4/1983	14.80%	10.96%	3.84%
10/7/1983	16.00%	10.97%	5.03%
10/13/1983	15.52%	10.99%	4.53%
10/17/1983	15.50%	11.00%	4.50%
10/18/1983	14.50%	11.00%	3.50%
10/19/1983	16.50%	11.01%	5.49%
10/19/1983	16.25%	11.01%	5.24%
10/26/1983	15.00%	11.04%	3.96%
10/27/1983	15.20%	11.04%	4.16%
11/1/1983	16.00%	11.06%	4.94%
11/9/1983	14.90%	11.09%	3.81%
11/10/1983	14.35%	11.10%	3.25%
11/23/1983	16.15%	11.13%	5.02%
11/23/1983	16.00%	11.13%	4.87%
11/30/1983	15.00%	11.14%	3.86%
12/5/1983	15.25%	11.15%	4.10%
12/6/1983	15.07%	11.15%	3.92%
12/8/1983	15.90%	11.16%	4.74%
12/9/1983	14.75%	11.17%	3.58%
12/12/1983	14.50%	11.17%	3.33%
12/15/1983	15.56%	11.19%	4.37%
12/19/1983	14.80%	11.21%	3.59%
12/20/1983	16.00%	11.22%	4.78%
12/20/1983	14.69%	11.22%	3.47%
12/20/1983	16.25%	11.22%	5.03%
12/22/1983	15.75%	11.23%	4.52%
12/22/1983	14.75%	11.23%	3.52%
1/3/1984	14.75%	11.27%	3.48%
1/10/1984	15.90%	11.30%	4.60%
1/12/1984	15.60%	11.31%	4.29%
1/18/1984	13.75%	11.33%	2.42%
1/19/1984	15.90%	11.33%	4.57%
1/30/1984	16.10%	11.37%	4.73%
1/31/1984	15.25%	11.37%	3.88%
2/1/1984	14.80%	11.38%	3.42%
2/6/1984	14.75%	11.40%	3.35%
2/6/1984	13.75%	11.40%	2.35%
2/9/1984	15.25%	11.42%	3.83%
2/15/1984	15.70%	11.44%	4.26%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
2/20/1984	15.00%	11.46%	3.54%
2/20/1984	15.00%	11.46%	3.54%
2/22/1984	14.75%	11.47%	3.28%
2/28/1984	14.50%	11.51%	2.99%
3/2/1984	14.25%	11.54%	2.71%
3/20/1984	16.00%	11.64%	4.36%
3/23/1984	15.50%	11.67%	3.83%
3/26/1984	14.71%	11.68%	3.03%
4/2/1984	15.50%	11.71%	3.79%
4/6/1984	14.74%	11.75%	2.99%
4/11/1984	15.72%	11.78%	3.94%
4/17/1984	15.00%	11.81%	3.19%
4/18/1984	16.20%	11.82%	4.38%
4/25/1984	14.64%	11.85%	2.79%
4/30/1984	14.40%	11.87%	2.53%
5/16/1984	14.69%	11.98%	2.71%
5/16/1984	15.00%	11.98%	3.02%
5/22/1984	14.40%	12.02%	2.38%
5/29/1984	15.10%	12.06%	3.04%
6/13/1984	15.25%	12.15%	3.10%
6/15/1984	15.60%	12.17%	3.43%
6/22/1984	16.25%	12.21%	4.04%
6/29/1984	15.25%	12.26%	2.99%
7/2/1984	13.35%	12.27%	1.08%
7/10/1984	16.00%	12.31%	3.69%
7/12/1984	16.50%	12.32%	4.18%
7/13/1984	16.25%	12.33%	3.92%
7/17/1984	14.14%	12.35%	1.79%
7/18/1984	15.50%	12.36%	3.14%
7/18/1984	15.30%	12.36%	2.94%
7/19/1984	14.30%	12.37%	1.93%
7/24/1984	16.79%	12.39%	4.40%
7/31/1984	16.00%	12.43%	3.57%
8/3/1984	14.25%	12.44%	1.81%
8/17/1984	14.30%	12.49%	1.81%
8/20/1984	15.00%	12.49%	2.51%
8/27/1984	16.30%	12.51%	3.79%
8/31/1984	15.55%	12.52%	3.03%
9/6/1984	16.00%	12.53%	3.47%
9/10/1984	14.75%	12.54%	2.21%
9/13/1984	15.00%	12.55%	2.45%
9/17/1984	17.38%	12.56%	4.82%
9/26/1984	14.50%	12.57%	1.93%
9/28/1984	15.00%	12.57%	2.43%
9/28/1984	16.25%	12.57%	3.68%
10/9/1984	14.75%	12.58%	2.17%
10/12/1984	15.60%	12.59%	3.01%
10/22/1984	15.00%	12.59%	2.41%
10/26/1984	16.40%	12.58%	3.82%
10/31/1984	16.25%	12.58%	3.67%
11/7/1984	15.60%	12.58%	3.02%
11/9/1984	16.00%	12.58%	3.42%
11/14/1984	15.75%	12.58%	3.17%
11/20/1984	15.25%	12.58%	2.67%
11/20/1984	15.92%	12.58%	3.34%
11/23/1984	15.00%	12.58%	2.42%
11/28/1984	16.15%	12.57%	3.58%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/3/1984	15.80%	12.56%	3.24%
12/4/1984	16.50%	12.56%	3.94%
12/18/1984	16.40%	12.53%	3.87%
12/19/1984	15.00%	12.53%	2.47%
12/19/1984	14.75%	12.53%	2.22%
12/20/1984	16.00%	12.53%	3.47%
12/28/1984	16.00%	12.50%	3.50%
1/3/1985	14.75%	12.49%	2.26%
1/10/1985	15.75%	12.47%	3.28%
1/11/1985	16.30%	12.46%	3.84%
1/23/1985	15.80%	12.43%	3.37%
1/24/1985	15.82%	12.43%	3.39%
1/25/1985	16.75%	12.42%	4.33%
1/30/1985	14.90%	12.40%	2.50%
1/31/1985	14.75%	12.39%	2.36%
2/8/1985	14.47%	12.35%	2.12%
3/1/1985	13.84%	12.31%	1.53%
3/8/1985	16.85%	12.28%	4.57%
3/14/1985	15.50%	12.25%	3.25%
3/15/1985	15.62%	12.25%	3.37%
3/29/1985	15.62%	12.17%	3.45%
4/3/1985	14.60%	12.14%	2.46%
4/9/1985	15.50%	12.11%	3.39%
4/16/1985	15.70%	12.06%	3.64%
4/22/1985	14.00%	12.02%	1.98%
4/26/1985	15.50%	11.98%	3.52%
4/29/1985	15.00%	11.97%	3.03%
5/2/1985	14.68%	11.94%	2.74%
5/8/1985	15.62%	11.89%	3.73%
5/10/1985	16.50%	11.87%	4.63%
5/29/1985	14.61%	11.73%	2.88%
5/31/1985	16.00%	11.71%	4.29%
6/14/1985	15.50%	11.61%	3.89%
7/9/1985	15.00%	11.45%	3.55%
7/16/1985	14.50%	11.39%	3.11%
7/26/1985	14.50%	11.33%	3.17%
8/2/1985	14.80%	11.29%	3.51%
8/7/1985	15.00%	11.27%	3.73%
8/28/1985	14.25%	11.15%	3.10%
8/28/1985	15.50%	11.15%	4.35%
8/29/1985	14.50%	11.15%	3.35%
9/9/1985	14.90%	11.11%	3.79%
9/9/1985	14.60%	11.11%	3.49%
9/17/1985	14.90%	11.08%	3.82%
9/23/1985	15.00%	11.06%	3.94%
9/27/1985	15.50%	11.05%	4.45%
9/27/1985	15.80%	11.05%	4.75%
10/2/1985	14.00%	11.03%	2.97%
10/2/1985	14.75%	11.03%	3.72%
10/3/1985	15.25%	11.03%	4.22%
10/24/1985	15.40%	10.96%	4.44%
10/24/1985	15.85%	10.96%	4.89%
10/24/1985	15.82%	10.96%	4.86%
10/28/1985	16.00%	10.95%	5.05%
10/29/1985	16.65%	10.94%	5.71%
10/31/1985	15.06%	10.93%	4.13%
11/4/1985	14.50%	10.92%	3.58%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
11/7/1985	15.50%	10.90%	4.60%
11/8/1985	14.30%	10.89%	3.41%
12/12/1985	14.75%	10.73%	4.02%
12/18/1985	15.00%	10.69%	4.31%
12/20/1985	15.00%	10.67%	4.33%
12/20/1985	14.50%	10.67%	3.83%
12/20/1985	14.50%	10.67%	3.83%
1/24/1986	15.40%	10.41%	4.99%
1/31/1986	15.00%	10.35%	4.65%
2/5/1986	15.00%	10.32%	4.68%
2/5/1986	15.75%	10.32%	5.43%
2/10/1986	13.30%	10.29%	3.01%
2/11/1986	12.50%	10.28%	2.22%
2/14/1986	14.40%	10.24%	4.16%
2/18/1986	16.00%	10.23%	5.77%
2/24/1986	14.50%	10.18%	4.32%
2/26/1986	14.00%	10.15%	3.85%
3/5/1986	14.90%	10.08%	4.82%
3/11/1986	14.50%	10.02%	4.48%
3/12/1986	13.50%	10.00%	3.50%
3/27/1986	14.10%	9.86%	4.24%
3/31/1986	13.50%	9.84%	3.66%
4/1/1986	14.00%	9.83%	4.17%
4/2/1986	15.50%	9.81%	5.69%
4/4/1986	15.00%	9.78%	5.22%
4/14/1986	13.40%	9.69%	3.71%
4/23/1986	15.00%	9.57%	5.43%
5/16/1986	14.50%	9.32%	5.18%
5/16/1986	14.50%	9.32%	5.18%
5/29/1986	13.90%	9.19%	4.71%
5/30/1986	15.10%	9.18%	5.92%
6/2/1986	12.81%	9.17%	3.64%
6/11/1986	14.00%	9.07%	4.93%
6/24/1986	16.63%	8.94%	7.69%
6/26/1986	14.75%	8.91%	5.84%
6/26/1986	12.00%	8.91%	3.09%
6/30/1986	13.00%	8.87%	4.13%
7/10/1986	14.34%	8.75%	5.59%
7/11/1986	12.75%	8.73%	4.02%
7/14/1986	12.60%	8.71%	3.89%
7/17/1986	12.40%	8.66%	3.74%
7/25/1986	14.25%	8.57%	5.68%
8/6/1986	13.50%	8.44%	5.06%
8/14/1986	13.50%	8.35%	5.15%
9/16/1986	12.75%	8.06%	4.69%
9/19/1986	13.25%	8.03%	5.22%
10/1/1986	14.00%	7.95%	6.05%
10/3/1986	13.40%	7.93%	5.47%
10/31/1986	13.50%	7.77%	5.73%
11/5/1986	13.00%	7.75%	5.25%
12/3/1986	12.90%	7.58%	5.32%
12/4/1986	14.44%	7.58%	6.86%
12/16/1986	13.60%	7.52%	6.08%
12/22/1986	13.80%	7.51%	6.29%
12/30/1986	13.00%	7.49%	5.51%
1/2/1987	13.00%	7.49%	5.51%
1/12/1987	12.40%	7.47%	4.93%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/27/1987	12.71%	7.46%	5.25%
3/2/1987	12.47%	7.47%	5.00%
3/3/1987	13.60%	7.47%	6.13%
3/4/1987	12.38%	7.47%	4.91%
3/10/1987	13.50%	7.47%	6.03%
3/13/1987	13.00%	7.47%	5.53%
3/31/1987	13.00%	7.46%	5.54%
4/6/1987	13.00%	7.47%	5.53%
4/14/1987	12.50%	7.49%	5.01%
4/16/1987	14.50%	7.50%	7.00%
4/27/1987	12.00%	7.54%	4.46%
5/5/1987	12.85%	7.58%	5.27%
5/12/1987	12.65%	7.62%	5.03%
5/28/1987	13.50%	7.70%	5.80%
6/15/1987	13.20%	7.78%	5.42%
6/29/1987	15.00%	7.83%	7.17%
6/30/1987	12.50%	7.84%	4.66%
7/8/1987	12.00%	7.86%	4.14%
7/10/1987	12.90%	7.86%	5.04%
7/15/1987	13.50%	7.88%	5.62%
7/16/1987	15.00%	7.88%	7.12%
7/16/1987	13.50%	7.88%	5.62%
7/27/1987	13.40%	7.92%	5.48%
7/27/1987	13.50%	7.92%	5.58%
7/27/1987	13.00%	7.92%	5.08%
7/31/1987	12.98%	7.95%	5.03%
8/26/1987	12.63%	8.06%	4.57%
8/26/1987	12.75%	8.06%	4.69%
8/27/1987	13.25%	8.06%	5.19%
9/9/1987	13.00%	8.14%	4.86%
9/30/1987	12.75%	8.31%	4.44%
9/30/1987	13.00%	8.31%	4.69%
10/2/1987	11.50%	8.33%	3.17%
10/15/1987	13.00%	8.43%	4.57%
11/2/1987	13.00%	8.55%	4.45%
11/19/1987	13.00%	8.64%	4.36%
11/30/1987	12.00%	8.68%	3.32%
12/3/1987	14.20%	8.70%	5.50%
12/15/1987	13.25%	8.77%	4.48%
12/16/1987	13.72%	8.78%	4.94%
12/16/1987	13.50%	8.78%	4.72%
12/17/1987	11.75%	8.79%	2.96%
12/18/1987	13.50%	8.80%	4.70%
12/21/1987	12.01%	8.81%	3.20%
12/22/1987	12.00%	8.81%	3.19%
12/22/1987	12.75%	8.81%	3.94%
12/22/1987	13.00%	8.81%	4.19%
12/22/1987	12.00%	8.81%	3.19%
1/20/1988	13.80%	8.94%	4.86%
1/26/1988	13.90%	8.95%	4.95%
1/29/1988	13.20%	8.96%	4.24%
2/4/1988	12.60%	8.96%	3.64%
3/1/1988	11.56%	8.94%	2.62%
3/23/1988	12.87%	8.92%	3.95%
3/24/1988	11.24%	8.92%	2.32%
3/30/1988	12.72%	8.92%	3.80%
4/1/1988	12.50%	8.92%	3.58%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
4/7/1988	13.25%	8.93%	4.32%
4/25/1988	10.96%	8.96%	2.00%
5/3/1988	12.91%	8.97%	3.94%
5/11/1988	13.50%	8.99%	4.51%
5/16/1988	13.00%	8.99%	4.01%
6/30/1988	12.75%	9.00%	3.75%
7/1/1988	12.75%	8.99%	3.76%
7/20/1988	13.40%	8.96%	4.44%
8/5/1988	12.75%	8.92%	3.83%
8/23/1988	11.70%	8.93%	2.77%
8/29/1988	12.75%	8.94%	3.81%
8/30/1988	13.50%	8.94%	4.56%
9/8/1988	12.60%	8.95%	3.65%
10/13/1988	13.10%	8.93%	4.17%
12/19/1988	13.00%	9.02%	3.98%
12/20/1988	13.00%	9.02%	3.98%
12/20/1988	12.25%	9.02%	3.23%
12/21/1988	12.90%	9.02%	3.88%
12/27/1988	13.00%	9.03%	3.97%
12/28/1988	13.10%	9.03%	4.07%
12/30/1988	13.40%	9.04%	4.36%
1/27/1989	13.00%	9.05%	3.95%
1/31/1989	13.00%	9.05%	3.95%
2/17/1989	13.00%	9.05%	3.95%
2/20/1989	12.40%	9.05%	3.35%
3/1/1989	12.76%	9.05%	3.71%
3/8/1989	13.00%	9.05%	3.95%
3/30/1989	14.00%	9.05%	4.95%
4/5/1989	14.20%	9.05%	5.15%
4/18/1989	13.00%	9.05%	3.95%
5/5/1989	12.40%	9.05%	3.35%
6/2/1989	13.20%	9.00%	4.20%
6/8/1989	13.50%	8.98%	4.52%
6/27/1989	13.25%	8.91%	4.34%
6/30/1989	13.00%	8.90%	4.10%
8/14/1989	12.50%	8.77%	3.73%
9/28/1989	12.25%	8.63%	3.62%
10/24/1989	12.50%	8.54%	3.96%
11/9/1989	13.00%	8.49%	4.51%
12/15/1989	13.00%	8.34%	4.66%
12/20/1989	12.90%	8.32%	4.58%
12/21/1989	12.90%	8.31%	4.59%
12/27/1989	13.00%	8.29%	4.71%
12/27/1989	12.50%	8.29%	4.21%
1/10/1990	12.80%	8.24%	4.56%
1/11/1990	12.90%	8.24%	4.66%
1/17/1990	12.80%	8.22%	4.58%
1/26/1990	12.00%	8.20%	3.80%
2/9/1990	12.10%	8.17%	3.93%
2/24/1990	12.86%	8.15%	4.71%
3/30/1990	12.90%	8.16%	4.74%
4/4/1990	15.76%	8.17%	7.59%
4/12/1990	12.52%	8.18%	4.34%
4/19/1990	12.75%	8.20%	4.55%
5/21/1990	12.10%	8.28%	3.82%
5/29/1990	12.40%	8.30%	4.10%
5/31/1990	12.00%	8.30%	3.70%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
6/4/1990	12.90%	8.30%	4.60%
6/6/1990	12.25%	8.31%	3.94%
6/15/1990	13.20%	8.32%	4.88%
6/20/1990	12.92%	8.32%	4.60%
6/27/1990	12.90%	8.33%	4.57%
6/29/1990	12.50%	8.33%	4.17%
7/6/1990	12.10%	8.34%	3.76%
7/6/1990	12.35%	8.34%	4.01%
8/10/1990	12.55%	8.41%	4.14%
8/16/1990	13.21%	8.43%	4.78%
8/22/1990	13.10%	8.45%	4.65%
8/24/1990	13.00%	8.46%	4.54%
9/26/1990	11.45%	8.59%	2.86%
10/2/1990	13.00%	8.61%	4.39%
10/5/1990	12.84%	8.62%	4.22%
10/19/1990	13.00%	8.67%	4.33%
10/25/1990	12.30%	8.68%	3.62%
11/21/1990	12.70%	8.69%	4.01%
12/13/1990	12.30%	8.67%	3.63%
12/17/1990	12.87%	8.67%	4.20%
12/18/1990	13.10%	8.67%	4.43%
12/19/1990	12.00%	8.66%	3.34%
12/20/1990	12.75%	8.66%	4.09%
12/21/1990	12.50%	8.66%	3.84%
12/27/1990	12.79%	8.66%	4.13%
1/2/1991	13.10%	8.65%	4.45%
1/4/1991	12.50%	8.65%	3.85%
1/15/1991	12.75%	8.64%	4.11%
1/25/1991	11.70%	8.63%	3.07%
2/4/1991	12.50%	8.60%	3.90%
2/7/1991	12.50%	8.59%	3.91%
2/12/1991	13.00%	8.58%	4.43%
2/14/1991	12.72%	8.57%	4.15%
2/22/1991	12.80%	8.55%	4.25%
3/6/1991	13.10%	8.53%	4.57%
3/8/1991	13.00%	8.52%	4.48%
3/8/1991	12.30%	8.52%	3.78%
4/22/1991	13.00%	8.49%	4.51%
5/7/1991	13.50%	8.47%	5.03%
5/13/1991	13.25%	8.47%	4.78%
5/30/1991	12.75%	8.44%	4.31%
6/12/1991	12.00%	8.41%	3.59%
6/25/1991	11.70%	8.39%	3.31%
6/28/1991	12.50%	8.38%	4.12%
7/1/1991	12.00%	8.38%	3.62%
7/3/1991	12.50%	8.37%	4.13%
7/19/1991	12.10%	8.34%	3.76%
8/1/1991	12.90%	8.32%	4.58%
8/16/1991	13.20%	8.29%	4.91%
9/27/1991	12.50%	8.23%	4.27%
9/30/1991	12.25%	8.23%	4.02%
10/17/1991	13.00%	8.20%	4.80%
10/23/1991	12.55%	8.20%	4.35%
10/23/1991	12.50%	8.20%	4.30%
10/31/1991	11.80%	8.19%	3.61%
11/1/1991	12.00%	8.19%	3.81%
11/5/1991	12.25%	8.19%	4.06%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
11/12/1991	13.25%	8.18%	5.07%
11/12/1991	12.50%	8.18%	4.32%
11/25/1991	12.40%	8.18%	4.22%
11/26/1991	11.60%	8.18%	3.42%
11/26/1991	12.50%	8.18%	4.32%
11/27/1991	12.10%	8.18%	3.92%
12/18/1991	12.25%	8.15%	4.10%
12/19/1991	12.80%	8.15%	4.65%
12/19/1991	12.60%	8.15%	4.45%
12/20/1991	12.65%	8.14%	4.51%
1/9/1992	12.80%	8.09%	4.71%
1/16/1992	12.75%	8.07%	4.68%
1/21/1992	12.00%	8.06%	3.94%
1/22/1992	13.00%	8.06%	4.94%
1/27/1992	12.65%	8.05%	4.60%
1/31/1992	12.00%	8.04%	3.96%
2/11/1992	12.40%	8.03%	4.37%
2/25/1992	12.50%	8.01%	4.49%
3/16/1992	11.43%	7.98%	3.45%
3/18/1992	12.28%	7.98%	4.30%
4/2/1992	12.10%	7.95%	4.15%
4/9/1992	11.45%	7.94%	3.51%
4/10/1992	11.50%	7.93%	3.57%
4/14/1992	11.50%	7.93%	3.57%
5/5/1992	11.50%	7.89%	3.61%
5/12/1992	12.46%	7.88%	4.58%
5/12/1992	11.87%	7.88%	3.99%
6/1/1992	12.30%	7.87%	4.43%
6/12/1992	10.90%	7.86%	3.04%
6/26/1992	12.35%	7.85%	4.50%
6/29/1992	11.00%	7.85%	3.15%
6/30/1992	13.00%	7.85%	5.15%
7/13/1992	11.90%	7.84%	4.06%
7/13/1992	13.50%	7.84%	5.66%
7/22/1992	11.20%	7.83%	3.37%
8/3/1992	12.00%	7.81%	4.19%
8/6/1992	12.50%	7.80%	4.70%
9/22/1992	12.00%	7.71%	4.29%
9/28/1992	11.40%	7.71%	3.69%
9/30/1992	11.75%	7.70%	4.05%
10/2/1992	13.00%	7.70%	5.30%
10/12/1992	12.20%	7.70%	4.50%
10/16/1992	13.16%	7.70%	5.46%
10/30/1992	11.75%	7.71%	4.04%
11/3/1992	12.00%	7.71%	4.29%
12/3/1992	11.85%	7.68%	4.17%
12/15/1992	11.00%	7.66%	3.34%
12/16/1992	11.90%	7.66%	4.24%
12/16/1992	12.40%	7.66%	4.74%
12/17/1992	12.00%	7.66%	4.34%
12/22/1992	12.40%	7.65%	4.75%
12/22/1992	12.30%	7.65%	4.65%
12/29/1992	12.25%	7.63%	4.62%
12/30/1992	12.00%	7.63%	4.37%
12/31/1992	11.90%	7.63%	4.27%
1/12/1993	12.00%	7.61%	4.39%
1/21/1993	11.25%	7.59%	3.66%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
2/2/1993	11.40%	7.56%	3.84%
2/15/1993	12.30%	7.52%	4.78%
2/24/1993	11.90%	7.49%	4.41%
2/26/1993	12.20%	7.48%	4.72%
2/26/1993	11.80%	7.48%	4.32%
4/23/1993	11.75%	7.29%	4.46%
5/11/1993	11.75%	7.25%	4.50%
5/14/1993	11.50%	7.24%	4.26%
5/25/1993	11.50%	7.23%	4.27%
5/28/1993	11.00%	7.22%	3.78%
6/3/1993	12.00%	7.21%	4.79%
6/16/1993	11.50%	7.19%	4.31%
6/18/1993	12.10%	7.18%	4.92%
6/25/1993	11.67%	7.17%	4.50%
7/21/1993	11.38%	7.10%	4.28%
7/23/1993	10.46%	7.09%	3.37%
8/24/1993	11.50%	6.96%	4.54%
9/21/1993	10.50%	6.81%	3.69%
9/29/1993	11.47%	6.77%	4.70%
9/30/1993	11.60%	6.76%	4.84%
11/2/1993	10.80%	6.60%	4.20%
11/12/1993	12.00%	6.57%	5.43%
11/26/1993	11.00%	6.52%	4.48%
12/14/1993	10.55%	6.48%	4.07%
12/16/1993	10.60%	6.48%	4.12%
12/21/1993	11.30%	6.47%	4.83%
1/4/1994	10.07%	6.44%	3.63%
1/13/1994	11.00%	6.42%	4.58%
1/21/1994	11.00%	6.40%	4.60%
1/28/1994	11.35%	6.39%	4.96%
2/3/1994	11.40%	6.38%	5.02%
2/17/1994	10.60%	6.36%	4.24%
2/25/1994	12.00%	6.35%	5.65%
2/25/1994	11.25%	6.35%	4.90%
3/1/1994	11.00%	6.35%	4.65%
3/4/1994	11.00%	6.35%	4.65%
4/25/1994	11.00%	6.41%	4.59%
5/10/1994	11.75%	6.45%	5.30%
5/13/1994	10.50%	6.46%	4.04%
6/3/1994	11.00%	6.54%	4.46%
6/27/1994	11.40%	6.65%	4.75%
8/5/1994	12.75%	6.88%	5.87%
10/31/1994	10.00%	7.33%	2.67%
11/9/1994	10.85%	7.39%	3.46%
11/9/1994	10.85%	7.39%	3.46%
11/18/1994	11.20%	7.45%	3.75%
11/22/1994	11.60%	7.47%	4.13%
11/28/1994	11.06%	7.49%	3.57%
12/8/1994	11.50%	7.54%	3.96%
12/8/1994	11.70%	7.54%	4.16%
12/14/1994	10.95%	7.56%	3.39%
12/15/1994	11.50%	7.57%	3.93%
12/19/1994	11.50%	7.58%	3.92%
12/28/1994	12.15%	7.61%	4.54%
1/9/1995	12.28%	7.64%	4.64%
1/31/1995	11.00%	7.69%	3.31%
2/10/1995	12.60%	7.70%	4.90%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
2/17/1995	11.90%	7.70%	4.20%
3/9/1995	11.50%	7.71%	3.79%
3/20/1995	12.00%	7.72%	4.28%
3/23/1995	12.81%	7.72%	5.09%
3/29/1995	11.60%	7.72%	3.88%
4/6/1995	11.10%	7.71%	3.39%
4/7/1995	11.00%	7.71%	3.29%
4/19/1995	11.00%	7.70%	3.30%
5/12/1995	11.63%	7.68%	3.95%
5/25/1995	11.20%	7.65%	3.55%
6/9/1995	11.25%	7.60%	3.65%
6/21/1995	12.25%	7.56%	4.69%
6/30/1995	11.10%	7.52%	3.58%
9/11/1995	11.30%	7.20%	4.10%
9/27/1995	11.75%	7.12%	4.63%
9/27/1995	11.50%	7.12%	4.38%
9/27/1995	11.30%	7.12%	4.18%
9/29/1995	11.00%	7.11%	3.89%
11/9/1995	12.36%	6.90%	5.46%
11/9/1995	11.38%	6.90%	4.48%
11/17/1995	11.00%	6.86%	4.14%
12/4/1995	11.35%	6.78%	4.57%
12/11/1995	11.40%	6.74%	4.66%
12/20/1995	11.60%	6.70%	4.90%
12/27/1995	12.00%	6.66%	5.34%
2/5/1996	12.25%	6.48%	5.77%
3/29/1996	10.67%	6.42%	4.25%
4/8/1996	11.00%	6.42%	4.58%
4/11/1996	12.59%	6.43%	6.16%
4/11/1996	12.59%	6.43%	6.16%
4/24/1996	11.25%	6.43%	4.82%
4/30/1996	11.00%	6.43%	4.57%
5/13/1996	11.00%	6.44%	4.56%
5/23/1996	11.25%	6.43%	4.82%
6/25/1996	11.25%	6.48%	4.77%
6/27/1996	11.20%	6.48%	4.72%
8/12/1996	10.40%	6.57%	3.83%
9/27/1996	11.00%	6.71%	4.29%
10/16/1996	12.25%	6.76%	5.49%
11/5/1996	11.00%	6.81%	4.19%
11/26/1996	11.30%	6.83%	4.47%
12/18/1996	11.75%	6.83%	4.92%
12/31/1996	11.50%	6.83%	4.67%
1/3/1997	10.70%	6.83%	3.87%
2/13/1997	11.80%	6.82%	4.98%
2/20/1997	11.80%	6.82%	4.98%
3/31/1997	10.02%	6.80%	3.22%
4/2/1997	11.65%	6.80%	4.85%
4/28/1997	11.50%	6.81%	4.69%
4/29/1997	11.70%	6.81%	4.89%
7/17/1997	12.00%	6.77%	5.23%
12/12/1997	11.00%	6.60%	4.40%
12/23/1997	11.12%	6.57%	4.55%
2/2/1998	12.75%	6.39%	6.36%
3/2/1998	11.25%	6.29%	4.96%
3/6/1998	10.75%	6.27%	4.48%
3/20/1998	10.50%	6.22%	4.28%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
4/30/1998	12.20%	6.12%	6.08%
7/10/1998	11.40%	5.94%	5.46%
9/15/1998	11.90%	5.78%	6.12%
11/30/1998	12.60%	5.58%	7.02%
12/10/1998	12.20%	5.54%	6.66%
12/17/1998	12.10%	5.52%	6.58%
2/5/1999	10.30%	5.38%	4.92%
3/4/1999	10.50%	5.34%	5.16%
4/6/1999	10.94%	5.32%	5.62%
7/29/1999	10.75%	5.52%	5.23%
9/23/1999	10.75%	5.70%	5.05%
11/17/1999	11.10%	5.90%	5.20%
1/7/2000	11.50%	6.05%	5.45%
1/7/2000	11.50%	6.05%	5.45%
2/17/2000	10.60%	6.17%	4.43%
3/28/2000	11.25%	6.20%	5.05%
5/24/2000	11.00%	6.18%	4.82%
7/18/2000	12.20%	6.16%	6.04%
9/29/2000	11.16%	6.03%	5.13%
11/28/2000	12.90%	5.89%	7.01%
11/30/2000	12.10%	5.88%	6.22%
1/23/2001	11.25%	5.79%	5.46%
2/8/2001	11.50%	5.77%	5.73%
5/8/2001	10.75%	5.62%	5.13%
6/26/2001	11.00%	5.62%	5.38%
7/25/2001	11.02%	5.60%	5.42%
7/25/2001	11.02%	5.60%	5.42%
7/31/2001	11.00%	5.59%	5.41%
8/31/2001	10.50%	5.56%	4.94%
9/7/2001	10.75%	5.55%	5.20%
9/10/2001	11.00%	5.55%	5.45%
9/20/2001	10.00%	5.55%	4.45%
10/24/2001	10.30%	5.54%	4.76%
11/28/2001	10.60%	5.49%	5.11%
12/3/2001	12.88%	5.49%	7.39%
12/20/2001	12.50%	5.50%	7.00%
1/22/2002	10.00%	5.50%	4.50%
3/27/2002	10.10%	5.45%	4.65%
4/22/2002	11.80%	5.45%	6.35%
5/28/2002	10.17%	5.46%	4.71%
6/10/2002	12.00%	5.47%	6.53%
6/18/2002	11.16%	5.48%	5.68%
6/20/2002	12.30%	5.48%	6.82%
6/20/2002	11.00%	5.48%	5.52%
7/15/2002	11.00%	5.48%	5.52%
9/12/2002	12.30%	5.45%	6.85%
9/26/2002	10.45%	5.41%	5.04%
12/4/2002	11.55%	5.29%	6.26%
12/13/2002	11.75%	5.27%	6.48%
12/20/2002	11.40%	5.25%	6.15%
1/8/2003	11.10%	5.19%	5.91%
1/31/2003	12.45%	5.13%	7.32%
2/28/2003	12.30%	5.05%	7.25%
3/6/2003	10.75%	5.03%	5.72%
3/7/2003	9.96%	5.02%	4.94%
3/20/2003	12.00%	4.98%	7.02%
4/3/2003	12.00%	4.96%	7.04%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
4/15/2003	11.15%	4.94%	6.21%
6/25/2003	10.75%	4.79%	5.96%
6/26/2003	10.75%	4.79%	5.96%
7/9/2003	9.75%	4.79%	4.96%
7/16/2003	9.75%	4.79%	4.96%
7/25/2003	9.50%	4.80%	4.70%
8/26/2003	10.50%	4.83%	5.67%
12/17/2003	10.70%	4.94%	5.76%
12/17/2003	9.85%	4.94%	4.91%
12/18/2003	11.50%	4.94%	6.56%
12/19/2003	12.00%	4.94%	7.06%
12/19/2003	12.00%	4.94%	7.06%
12/23/2003	10.50%	4.94%	5.56%
1/13/2004	12.00%	4.95%	7.05%
3/2/2004	10.75%	4.99%	5.76%
3/26/2004	10.25%	5.02%	5.23%
4/5/2004	11.25%	5.03%	6.22%
5/18/2004	10.50%	5.07%	5.43%
5/25/2004	10.25%	5.08%	5.17%
5/27/2004	10.25%	5.08%	5.17%
6/2/2004	11.22%	5.08%	6.14%
6/30/2004	10.50%	5.10%	5.40%
6/30/2004	10.50%	5.10%	5.40%
7/16/2004	11.60%	5.11%	6.49%
8/25/2004	10.25%	5.10%	5.15%
9/9/2004	10.40%	5.10%	5.30%
11/9/2004	10.50%	5.07%	5.43%
11/23/2004	11.00%	5.06%	5.94%
12/14/2004	10.97%	5.07%	5.90%
12/21/2004	11.50%	5.07%	6.43%
12/21/2004	11.25%	5.07%	6.18%
12/22/2004	10.70%	5.07%	5.63%
12/22/2004	11.50%	5.07%	6.43%
12/29/2004	9.85%	5.07%	4.78%
1/6/2005	10.70%	5.08%	5.62%
2/18/2005	10.30%	4.98%	5.32%
2/25/2005	10.50%	4.96%	5.54%
3/10/2005	11.00%	4.93%	6.07%
3/24/2005	10.30%	4.90%	5.40%
4/4/2005	10.00%	4.88%	5.12%
4/7/2005	10.25%	4.87%	5.38%
5/18/2005	10.25%	4.78%	5.47%
5/25/2005	10.75%	4.76%	5.99%
5/26/2005	9.75%	4.76%	4.99%
6/1/2005	9.75%	4.75%	5.00%
7/19/2005	11.50%	4.64%	6.86%
8/5/2005	11.75%	4.62%	7.13%
8/15/2005	10.13%	4.61%	5.52%
9/28/2005	10.00%	4.54%	5.46%
10/4/2005	10.75%	4.54%	6.21%
12/12/2005	11.00%	4.55%	6.45%
12/13/2005	10.75%	4.55%	6.20%
12/21/2005	10.29%	4.54%	5.75%
12/21/2005	10.40%	4.54%	5.86%
12/22/2005	11.15%	4.54%	6.61%
12/22/2005	11.00%	4.54%	6.46%
12/28/2005	10.00%	4.54%	5.46%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/28/2005	10.00%	4.54%	5.46%
1/5/2006	11.00%	4.53%	6.47%
1/27/2006	9.75%	4.52%	5.23%
3/3/2006	10.39%	4.53%	5.86%
4/17/2006	10.20%	4.61%	5.59%
4/26/2006	10.60%	4.64%	5.96%
5/17/2006	11.60%	4.69%	6.91%
6/6/2006	10.00%	4.74%	5.26%
6/27/2006	10.75%	4.80%	5.95%
7/6/2006	10.20%	4.83%	5.37%
7/24/2006	9.60%	4.86%	4.74%
7/26/2006	10.50%	4.86%	5.64%
7/28/2006	10.05%	4.86%	5.19%
8/23/2006	9.55%	4.89%	4.66%
9/1/2006	10.54%	4.90%	5.64%
9/14/2006	10.00%	4.91%	5.09%
10/6/2006	9.67%	4.92%	4.75%
11/21/2006	10.08%	4.95%	5.13%
11/21/2006	10.08%	4.95%	5.13%
11/21/2006	10.12%	4.95%	5.17%
12/1/2006	10.25%	4.95%	5.30%
12/1/2006	10.50%	4.95%	5.55%
12/7/2006	10.75%	4.95%	5.80%
12/21/2006	11.25%	4.95%	6.30%
12/21/2006	10.90%	4.95%	5.95%
12/22/2006	10.25%	4.95%	5.30%
1/5/2007	10.00%	4.95%	5.05%
1/11/2007	10.90%	4.95%	5.95%
1/11/2007	10.10%	4.95%	5.15%
1/11/2007	10.10%	4.95%	5.15%
1/12/2007	10.10%	4.95%	5.15%
1/13/2007	10.40%	4.95%	5.45%
1/19/2007	10.80%	4.94%	5.86%
3/21/2007	11.35%	4.87%	6.48%
3/22/2007	9.75%	4.86%	4.89%
5/15/2007	10.00%	4.81%	5.19%
5/17/2007	10.25%	4.81%	5.44%
5/17/2007	10.25%	4.81%	5.44%
5/22/2007	10.20%	4.80%	5.40%
5/22/2007	10.50%	4.80%	5.70%
5/23/2007	10.70%	4.80%	5.90%
5/25/2007	9.67%	4.80%	4.87%
6/15/2007	9.90%	4.82%	5.08%
6/21/2007	10.20%	4.83%	5.37%
6/22/2007	10.50%	4.83%	5.67%
6/28/2007	10.75%	4.84%	5.91%
7/12/2007	9.67%	4.86%	4.81%
7/19/2007	10.00%	4.87%	5.13%
7/19/2007	10.00%	4.87%	5.13%
8/15/2007	10.40%	4.88%	5.52%
10/9/2007	10.00%	4.91%	5.09%
10/17/2007	9.10%	4.91%	4.19%
10/31/2007	9.96%	4.90%	5.06%
11/29/2007	10.90%	4.87%	6.03%
12/6/2007	10.75%	4.86%	5.89%
12/13/2007	9.96%	4.86%	5.10%
12/14/2007	10.80%	4.86%	5.94%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/14/2007	10.70%	4.86%	5.84%
12/19/2007	10.20%	4.86%	5.34%
12/20/2007	10.20%	4.85%	5.35%
12/20/2007	11.00%	4.85%	6.15%
12/28/2007	10.25%	4.85%	5.40%
12/31/2007	11.25%	4.85%	6.40%
1/8/2008	10.75%	4.83%	5.92%
1/17/2008	10.75%	4.81%	5.94%
1/28/2008	9.40%	4.80%	4.60%
1/30/2008	10.00%	4.79%	5.21%
1/31/2008	10.71%	4.79%	5.92%
2/29/2008	10.25%	4.75%	5.50%
3/12/2008	10.25%	4.73%	5.52%
3/25/2008	9.10%	4.68%	4.42%
4/22/2008	10.25%	4.60%	5.65%
4/24/2008	10.10%	4.60%	5.50%
5/1/2008	10.70%	4.59%	6.11%
5/19/2008	11.00%	4.56%	6.44%
5/27/2008	10.00%	4.55%	5.45%
6/10/2008	10.70%	4.54%	6.16%
6/27/2008	11.04%	4.54%	6.50%
6/27/2008	10.50%	4.54%	5.96%
7/10/2008	10.43%	4.52%	5.91%
7/16/2008	9.40%	4.52%	4.88%
7/30/2008	10.80%	4.51%	6.29%
7/31/2008	10.70%	4.51%	6.19%
8/11/2008	10.25%	4.51%	5.74%
8/26/2008	10.18%	4.50%	5.68%
9/10/2008	10.30%	4.50%	5.80%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/30/2008	10.20%	4.48%	5.72%
10/8/2008	10.15%	4.46%	5.69%
11/13/2008	10.55%	4.45%	6.10%
11/17/2008	10.20%	4.44%	5.76%
12/1/2008	10.25%	4.40%	5.85%
12/23/2008	11.00%	4.27%	6.73%
12/29/2008	10.00%	4.24%	5.76%
12/29/2008	10.20%	4.24%	5.96%
12/31/2008	10.75%	4.22%	6.53%
1/14/2009	10.50%	4.15%	6.35%
1/21/2009	10.50%	4.12%	6.38%
1/21/2009	10.50%	4.12%	6.38%
1/21/2009	10.50%	4.12%	6.38%
1/27/2009	10.76%	4.09%	6.67%
1/30/2009	10.50%	4.08%	6.42%
2/4/2009	8.75%	4.06%	4.69%
3/4/2009	10.50%	3.96%	6.54%
3/12/2009	11.50%	3.93%	7.57%
4/2/2009	11.10%	3.85%	7.25%
4/21/2009	10.61%	3.80%	6.81%
4/24/2009	10.00%	3.79%	6.21%
4/30/2009	11.25%	3.78%	7.47%
5/4/2009	10.74%	3.77%	6.97%
5/20/2009	10.25%	3.74%	6.51%
5/28/2009	10.50%	3.74%	6.76%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
6/22/2009	10.00%	3.76%	6.24%
6/24/2009	10.80%	3.77%	7.03%
7/8/2009	10.63%	3.77%	6.86%
7/17/2009	10.50%	3.78%	6.72%
8/21/2009	10.25%	3.81%	6.44%
8/31/2009	10.25%	3.82%	6.43%
10/14/2009	10.70%	4.01%	6.69%
10/23/2009	10.88%	4.06%	6.82%
11/2/2009	10.70%	4.09%	6.61%
11/3/2009	10.70%	4.10%	6.60%
11/24/2009	10.25%	4.15%	6.10%
11/25/2009	10.75%	4.16%	6.59%
11/30/2009	10.35%	4.17%	6.18%
12/3/2009	10.50%	4.18%	6.32%
12/7/2009	10.70%	4.18%	6.52%
12/16/2009	11.00%	4.21%	6.79%
12/16/2009	10.90%	4.21%	6.69%
12/18/2009	10.40%	4.22%	6.18%
12/18/2009	10.40%	4.22%	6.18%
12/22/2009	10.20%	4.23%	5.97%
12/22/2009	10.40%	4.23%	6.17%
12/22/2009	10.40%	4.23%	6.17%
12/30/2009	10.00%	4.26%	5.74%
1/4/2010	10.80%	4.28%	6.52%
1/11/2010	11.00%	4.30%	6.70%
1/26/2010	10.13%	4.35%	5.78%
1/27/2010	10.40%	4.35%	6.05%
1/27/2010	10.40%	4.35%	6.05%
1/27/2010	10.70%	4.35%	6.35%
2/9/2010	9.80%	4.38%	5.42%
2/18/2010	10.60%	4.40%	6.20%
2/24/2010	10.18%	4.41%	5.77%
3/2/2010	9.63%	4.41%	5.22%
3/4/2010	10.50%	4.41%	6.09%
3/5/2010	10.50%	4.41%	6.09%
3/11/2010	11.90%	4.42%	7.48%
3/17/2010	10.00%	4.41%	5.59%
3/25/2010	10.15%	4.42%	5.73%
4/2/2010	10.10%	4.43%	5.67%
4/27/2010	10.00%	4.46%	5.54%
4/29/2010	9.90%	4.46%	5.44%
4/29/2010	10.06%	4.46%	5.60%
4/29/2010	10.26%	4.46%	5.80%
5/12/2010	10.30%	4.45%	5.85%
5/12/2010	10.30%	4.45%	5.85%
5/28/2010	10.10%	4.44%	5.66%
5/28/2010	10.20%	4.44%	5.76%
6/7/2010	10.30%	4.44%	5.86%
6/16/2010	10.00%	4.44%	5.56%
6/28/2010	9.67%	4.43%	5.24%
6/28/2010	10.50%	4.43%	6.07%
6/30/2010	9.40%	4.43%	4.97%
7/1/2010	10.25%	4.43%	5.82%
7/15/2010	10.53%	4.43%	6.10%
7/15/2010	10.70%	4.43%	6.27%
7/30/2010	10.70%	4.41%	6.29%
8/4/2010	10.50%	4.41%	6.09%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
8/6/2010	9.83%	4.41%	5.42%
8/25/2010	9.90%	4.37%	5.53%
9/3/2010	10.60%	4.35%	6.25%
9/14/2010	10.70%	4.33%	6.37%
9/16/2010	10.00%	4.33%	5.67%
9/16/2010	10.00%	4.33%	5.67%
9/30/2010	9.75%	4.29%	5.46%
10/14/2010	10.35%	4.24%	6.11%
10/28/2010	10.70%	4.21%	6.49%
11/2/2010	10.38%	4.20%	6.18%
11/4/2010	10.70%	4.20%	6.50%
11/19/2010	10.20%	4.18%	6.02%
11/22/2010	10.00%	4.18%	5.82%
12/1/2010	10.13%	4.16%	5.97%
12/6/2010	9.86%	4.15%	5.71%
12/9/2010	10.25%	4.15%	6.10%
12/13/2010	10.70%	4.15%	6.55%
12/14/2010	10.13%	4.15%	5.98%
12/15/2010	10.44%	4.15%	6.29%
12/17/2010	10.00%	4.15%	5.85%
12/20/2010	10.60%	4.15%	6.45%
12/21/2010	10.30%	4.14%	6.16%
12/27/2010	9.90%	4.14%	5.76%
12/29/2010	11.15%	4.14%	7.01%
1/5/2011	10.15%	4.13%	6.02%
1/12/2011	10.30%	4.12%	6.18%
1/13/2011	10.30%	4.12%	6.18%
1/18/2011	10.00%	4.12%	5.88%
1/20/2011	9.30%	4.12%	5.18%
1/20/2011	10.13%	4.12%	6.01%
1/31/2011	9.60%	4.12%	5.48%
2/3/2011	10.00%	4.12%	5.88%
2/25/2011	10.00%	4.14%	5.86%
3/25/2011	9.80%	4.18%	5.62%
3/30/2011	10.00%	4.18%	5.82%
4/12/2011	10.00%	4.21%	5.79%
4/25/2011	10.74%	4.23%	6.51%
4/26/2011	9.67%	4.23%	5.44%
4/27/2011	10.40%	4.24%	6.16%
5/4/2011	10.00%	4.24%	5.76%
5/4/2011	10.00%	4.24%	5.76%
5/24/2011	10.50%	4.27%	6.23%
6/8/2011	10.75%	4.30%	6.45%
6/16/2011	9.20%	4.32%	4.88%
6/17/2011	9.95%	4.32%	5.63%
7/13/2011	10.20%	4.36%	5.84%
8/1/2011	9.20%	4.39%	4.81%
8/8/2011	10.00%	4.38%	5.62%
8/11/2011	10.00%	4.38%	5.62%
8/12/2011	10.35%	4.37%	5.98%
8/19/2011	10.25%	4.36%	5.89%
9/2/2011	12.88%	4.32%	8.56%
9/22/2011	10.00%	4.24%	5.76%
10/12/2011	10.30%	4.14%	6.16%
10/20/2011	10.50%	4.10%	6.40%
11/30/2011	10.90%	3.87%	7.03%
11/30/2011	10.90%	3.87%	7.03%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/14/2011	10.00%	3.80%	6.20%
12/14/2011	10.30%	3.80%	6.50%
12/20/2011	10.20%	3.76%	6.44%
12/21/2011	10.20%	3.76%	6.44%
12/22/2011	9.90%	3.75%	6.15%
12/22/2011	10.40%	3.75%	6.65%
12/23/2011	10.19%	3.74%	6.45%
1/25/2012	10.50%	3.57%	6.93%
1/27/2012	10.50%	3.56%	6.94%
2/15/2012	10.20%	3.47%	6.73%
2/23/2012	9.90%	3.44%	6.46%
2/27/2012	10.25%	3.43%	6.82%
2/29/2012	10.40%	3.41%	6.99%
3/29/2012	10.37%	3.32%	7.05%
4/4/2012	10.00%	3.30%	6.70%
4/26/2012	10.00%	3.21%	6.79%
5/2/2012	10.00%	3.18%	6.82%
5/7/2012	9.80%	3.17%	6.63%
5/15/2012	10.00%	3.14%	6.86%
5/29/2012	10.05%	3.11%	6.94%
6/7/2012	10.30%	3.08%	7.22%
6/14/2012	9.40%	3.06%	6.34%
6/15/2012	10.40%	3.06%	7.34%
6/18/2012	9.60%	3.06%	6.54%
6/19/2012	9.25%	3.05%	6.20%
6/26/2012	10.10%	3.04%	7.06%
6/29/2012	10.00%	3.04%	6.96%
7/9/2012	10.20%	3.03%	7.17%
7/16/2012	9.80%	3.02%	6.78%
7/20/2012	9.81%	3.01%	6.80%
7/20/2012	9.31%	3.01%	6.30%
9/13/2012	9.80%	2.94%	6.86%
9/19/2012	10.05%	2.94%	7.11%
9/19/2012	9.80%	2.94%	6.86%
9/26/2012	9.50%	2.94%	6.56%
10/12/2012	9.60%	2.93%	6.67%
10/23/2012	9.75%	2.93%	6.82%
10/24/2012	10.30%	2.93%	7.37%
11/9/2012	10.30%	2.92%	7.38%
11/28/2012	10.40%	2.90%	7.50%
11/29/2012	9.75%	2.89%	6.86%
11/29/2012	9.88%	2.89%	6.99%
12/5/2012	10.40%	2.89%	7.51%
12/5/2012	9.71%	2.89%	6.82%
12/12/2012	9.80%	2.88%	6.92%
12/13/2012	10.50%	2.88%	7.62%
12/13/2012	9.50%	2.88%	6.62%
12/14/2012	10.40%	2.88%	7.52%
12/19/2012	9.71%	2.87%	6.84%
12/19/2012	10.25%	2.87%	7.38%
12/20/2012	9.80%	2.87%	6.93%
12/20/2012	10.40%	2.87%	7.53%
12/20/2012	10.30%	2.87%	7.43%
12/20/2012	10.45%	2.87%	7.58%
12/20/2012	9.50%	2.87%	6.63%
12/20/2012	10.25%	2.87%	7.38%
12/20/2012	10.25%	2.87%	7.38%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/21/2012	10.20%	2.87%	7.33%
12/26/2012	9.80%	2.86%	6.94%
1/9/2013	9.70%	2.85%	6.85%
1/9/2013	9.70%	2.85%	6.85%
1/9/2013	9.70%	2.85%	6.85%
1/16/2013	9.60%	2.84%	6.76%
1/16/2013	9.60%	2.84%	6.76%
2/13/2013	10.20%	2.84%	7.36%
2/22/2013	9.75%	2.85%	6.90%
2/27/2013	10.00%	2.86%	7.14%
3/14/2013	9.30%	2.88%	6.42%
3/27/2013	9.80%	2.90%	6.90%
5/1/2013	9.84%	2.94%	6.90%
5/15/2013	10.30%	2.96%	7.34%
5/30/2013	10.20%	2.98%	7.22%
5/31/2013	9.00%	2.98%	6.02%
6/11/2013	10.00%	3.00%	7.00%
6/21/2013	9.75%	3.02%	6.73%
6/25/2013	9.80%	3.03%	6.77%
7/12/2013	9.36%	3.07%	6.29%
8/8/2013	9.83%	3.14%	6.69%
8/14/2013	9.15%	3.16%	5.99%
9/11/2013	10.20%	3.26%	6.94%
9/11/2013	10.25%	3.26%	6.99%
9/24/2013	10.20%	3.31%	6.89%
10/3/2013	9.65%	3.33%	6.32%
11/6/2013	10.20%	3.41%	6.79%
11/21/2013	10.00%	3.44%	6.56%
11/26/2013	10.00%	3.45%	6.55%
12/3/2013	10.25%	3.47%	6.78%
12/4/2013	9.50%	3.47%	6.03%
12/5/2013	10.20%	3.48%	6.72%
12/9/2013	9.75%	3.48%	6.27%
12/9/2013	8.72%	3.48%	5.24%
12/13/2013	9.75%	3.50%	6.25%
12/16/2013	9.95%	3.50%	6.45%
12/16/2013	9.95%	3.50%	6.45%
12/16/2013	10.12%	3.50%	6.62%
12/17/2013	9.50%	3.51%	5.99%
12/17/2013	10.95%	3.51%	7.44%
12/18/2013	9.80%	3.51%	6.29%
12/18/2013	8.72%	3.51%	5.21%
12/19/2013	10.15%	3.51%	6.64%
12/30/2013	9.50%	3.54%	5.96%
2/20/2014	9.20%	3.68%	5.52%
2/26/2014	9.75%	3.69%	6.06%
3/17/2014	9.55%	3.72%	5.83%
3/26/2014	9.96%	3.73%	6.23%
3/26/2014	9.40%	3.73%	5.67%
4/2/2014	9.70%	3.73%	5.97%
5/16/2014	9.80%	3.70%	6.10%
5/30/2014	9.70%	3.68%	6.02%
6/6/2014	10.40%	3.67%	6.73%
6/30/2014	9.55%	3.64%	5.91%
7/2/2014	9.62%	3.64%	5.98%
7/10/2014	9.95%	3.63%	6.32%
7/23/2014	9.75%	3.61%	6.14%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
7/29/2014	9.45%	3.60%	5.85%
7/31/2014	9.90%	3.60%	6.30%
8/20/2014	9.75%	3.57%	6.18%
8/25/2014	9.60%	3.56%	6.04%
8/29/2014	9.80%	3.54%	6.26%
9/11/2014	9.60%	3.51%	6.09%
9/15/2014	10.25%	3.51%	6.74%
10/9/2014	9.80%	3.45%	6.35%
11/6/2014	9.56%	3.37%	6.19%
11/6/2014	10.20%	3.37%	6.83%
11/14/2014	10.20%	3.35%	6.85%
11/26/2014	9.70%	3.33%	6.37%
11/26/2014	10.20%	3.33%	6.87%
12/4/2014	9.68%	3.31%	6.37%
12/10/2014	9.25%	3.29%	5.96%
12/10/2014	9.25%	3.29%	5.96%
12/11/2014	10.07%	3.29%	6.78%
12/12/2014	10.20%	3.28%	6.92%
12/17/2014	9.17%	3.27%	5.90%
12/18/2014	9.83%	3.26%	6.57%
1/23/2015	9.50%	3.14%	6.36%
2/24/2015	9.83%	3.04%	6.79%
3/18/2015	9.75%	2.98%	6.77%
3/25/2015	9.50%	2.96%	6.54%
3/26/2015	9.72%	2.95%	6.77%
4/23/2015	10.20%	2.87%	7.33%
4/29/2015	9.53%	2.86%	6.67%
5/1/2015	9.60%	2.85%	6.75%
5/26/2015	9.75%	2.83%	6.92%
6/17/2015	9.00%	2.82%	6.18%
6/17/2015	9.00%	2.82%	6.18%
9/2/2015	9.50%	2.79%	6.71%
9/10/2015	9.30%	2.79%	6.51%
9/25/2015	9.60%	2.80%	6.80%
10/15/2015	9.00%	2.81%	6.19%
11/19/2015	10.30%	2.88%	7.42%
11/19/2015	10.00%	2.88%	7.12%
12/3/2015	10.00%	2.90%	7.10%
12/9/2015	9.14%	2.90%	6.24%
12/9/2015	9.14%	2.90%	6.24%
12/11/2015	10.30%	2.90%	7.40%
12/15/2015	9.60%	2.91%	6.69%
12/17/2015	9.70%	2.91%	6.79%
12/18/2015	9.50%	2.91%	6.59%
12/30/2015	9.50%	2.93%	6.57%
1/6/2016	9.50%	2.94%	6.56%
2/23/2016	9.75%	2.94%	6.81%
3/16/2016	9.85%	2.91%	6.94%
4/29/2016	9.80%	2.83%	6.97%
6/3/2016	9.75%	2.80%	6.95%
6/8/2016	9.48%	2.80%	6.68%
6/15/2016	9.00%	2.78%	6.22%
6/15/2016	9.00%	2.78%	6.22%
7/18/2016	9.98%	2.71%	7.27%
8/9/2016	9.85%	2.66%	7.19%
8/18/2016	9.50%	2.63%	6.87%
8/24/2016	9.75%	2.62%	7.13%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
9/1/2016	9.50%	2.59%	6.91%
9/8/2016	10.00%	2.58%	7.42%
9/28/2016	9.58%	2.54%	7.04%
9/30/2016	9.90%	2.53%	7.37%
11/9/2016	9.80%	2.48%	7.32%
11/10/2016	9.50%	2.48%	7.02%
11/15/2016	9.55%	2.49%	7.06%
11/18/2016	10.00%	2.50%	7.50%
11/29/2016	10.55%	2.51%	8.04%
12/1/2016	10.00%	2.51%	7.49%
12/6/2016	8.64%	2.52%	6.12%
12/6/2016	8.64%	2.52%	6.12%
12/7/2016	10.10%	2.52%	7.58%
12/12/2016	9.60%	2.53%	7.07%
12/14/2016	9.10%	2.53%	6.57%
12/19/2016	9.00%	2.54%	6.46%
12/19/2016	9.37%	2.54%	6.83%
12/22/2016	9.90%	2.55%	7.35%
12/22/2016	9.60%	2.55%	7.05%
12/28/2016	9.50%	2.55%	6.95%
1/18/2017	9.45%	2.58%	6.87%
1/24/2017	9.00%	2.59%	6.41%
1/31/2017	10.10%	2.60%	7.50%
2/15/2017	9.60%	2.62%	6.98%
2/22/2017	9.60%	2.64%	6.96%
2/24/2017	9.75%	2.64%	7.11%
2/24/2017	9.60%	2.64%	6.96%
2/28/2017	10.10%	2.64%	7.46%
3/2/2017	9.41%	2.65%	6.76%
3/20/2017	9.50%	2.68%	6.82%
4/4/2017	10.25%	2.71%	7.54%
4/12/2017	9.40%	2.74%	6.66%
4/20/2017	9.50%	2.76%	6.74%
5/3/2017	9.50%	2.79%	6.71%
5/11/2017	9.20%	2.81%	6.39%
5/18/2017	9.50%	2.83%	6.67%
5/23/2017	9.70%	2.84%	6.86%
6/16/2017	9.65%	2.89%	6.76%
6/22/2017	9.70%	2.90%	6.80%
6/22/2017	9.70%	2.90%	6.80%
7/24/2017	9.50%	2.95%	6.55%
8/15/2017	10.00%	2.97%	7.03%
9/22/2017	9.60%	2.93%	6.67%
9/28/2017	9.80%	2.92%	6.88%
10/20/2017	9.50%	2.91%	6.59%
10/26/2017	10.25%	2.91%	7.34%
10/26/2017	10.20%	2.91%	7.29%
10/26/2017	10.30%	2.91%	7.39%
11/6/2017	10.25%	2.90%	7.35%
11/15/2017	11.95%	2.89%	9.06%
11/30/2017	10.00%	2.88%	7.12%
11/30/2017	10.00%	2.88%	7.12%
12/5/2017	9.50%	2.88%	6.62%
12/6/2017	8.40%	2.87%	5.53%
12/6/2017	8.40%	2.87%	5.53%
12/7/2017	9.80%	2.87%	6.93%
12/14/2017	9.60%	2.86%	6.74%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/14/2017	9.65%	2.86%	6.79%
12/18/2017	9.50%	2.86%	6.64%
12/20/2017	9.58%	2.86%	6.72%
12/21/2017	9.10%	2.85%	6.25%
12/28/2017	9.50%	2.85%	6.65%
12/29/2017	9.51%	2.85%	6.66%
1/18/2018	9.70%	2.84%	6.86%
1/31/2018	9.30%	2.84%	6.46%
2/2/2018	9.98%	2.84%	7.14%
2/23/2018	9.90%	2.85%	7.05%
3/12/2018	9.25%	2.86%	6.39%
3/15/2018	9.00%	2.87%	6.13%
3/29/2018	10.00%	2.88%	7.12%
4/12/2018	9.90%	2.89%	7.01%
4/13/2018	9.73%	2.89%	6.84%
4/18/2018	10.00%	2.89%	7.11%
4/18/2018	9.25%	2.89%	6.36%
4/26/2018	9.50%	2.90%	6.60%
5/30/2018	9.95%	2.94%	7.01%
5/31/2018	9.50%	2.94%	6.56%
6/14/2018	8.80%	2.96%	5.84%
6/22/2018	9.50%	2.97%	6.53%
6/22/2018	9.90%	2.97%	6.93%
6/28/2018	9.35%	2.97%	6.38%
6/29/2018	9.50%	2.97%	6.53%
8/8/2018	9.53%	2.99%	6.54%
8/21/2018	9.70%	3.00%	6.70%
8/24/2018	9.28%	3.01%	6.27%
9/5/2018	9.56%	3.02%	6.54%
9/14/2018	10.00%	3.03%	6.97%
9/20/2018	9.80%	3.04%	6.76%
9/26/2018	10.00%	3.05%	6.95%
9/26/2018	9.77%	3.05%	6.72%
9/27/2018	9.30%	3.05%	6.25%
10/4/2018	9.85%	3.06%	6.79%
10/29/2018	9.60%	3.10%	6.50%
10/31/2018	9.99%	3.11%	6.88%
11/1/2018	8.69%	3.11%	5.58%
12/4/2018	8.69%	3.14%	5.55%
12/13/2018	9.30%	3.14%	6.16%
12/14/2018	9.50%	3.14%	6.36%
12/19/2018	9.84%	3.14%	6.70%
12/20/2018	9.65%	3.14%	6.51%
12/21/2018	9.30%	3.14%	6.16%
1/9/2019	10.00%	3.14%	6.86%
2/27/2019	9.75%	3.12%	6.63%
3/13/2019	9.60%	3.12%	6.48%
3/14/2019	9.00%	3.12%	5.88%
3/14/2019	9.40%	3.12%	6.28%
3/22/2019	9.65%	3.12%	6.53%
4/30/2019	9.73%	3.11%	6.62%
4/30/2019	9.73%	3.11%	6.62%
5/1/2019	9.50%	3.11%	6.39%
5/2/2019	10.00%	3.11%	6.89%
5/8/2019	9.50%	3.10%	6.40%
5/14/2019	8.75%	3.10%	5.65%
5/16/2019	9.50%	3.09%	6.41%

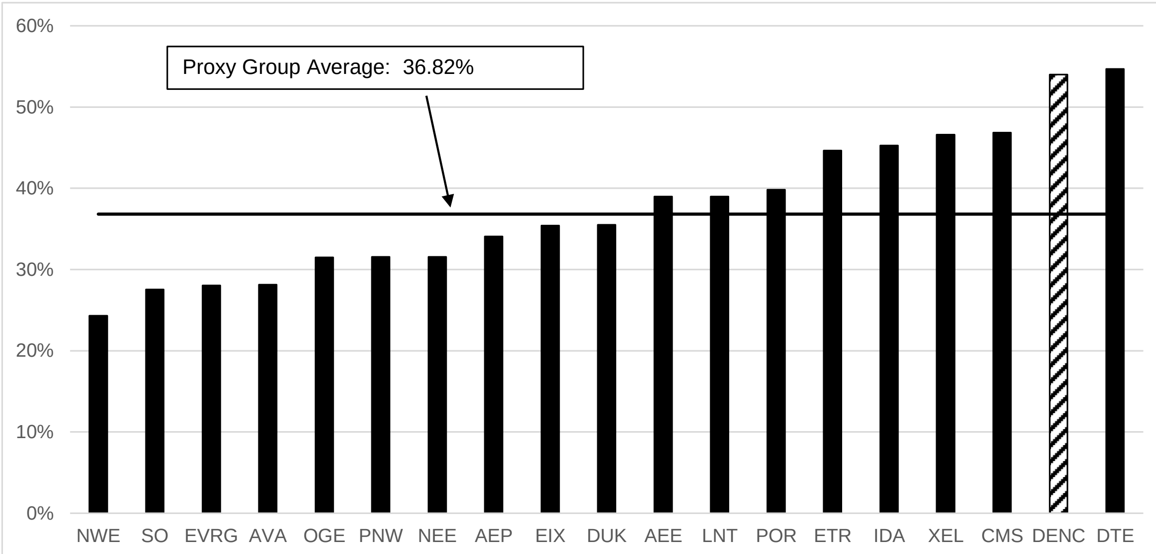
[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
5/23/2019	9.90%	3.09%	6.81%
8/12/2019	9.60%	2.90%	6.70%
8/29/2019	9.06%	2.81%	6.25%
9/4/2019	10.00%	2.78%	7.22%
9/30/2019	9.60%	2.70%	6.90%
10/31/2019	10.00%	2.60%	7.40%
10/31/2019	10.00%	2.60%	7.40%
11/7/2019	9.35%	2.58%	6.77%
11/29/2019	9.50%	2.52%	6.98%
12/4/2019	9.75%	2.51%	7.24%
12/4/2019	8.91%	2.51%	6.40%
12/16/2019	8.91%	2.48%	6.43%
12/17/2019	9.70%	2.48%	7.22%
12/17/2019	10.50%	2.48%	8.02%
12/19/2019	10.25%	2.47%	7.78%
12/19/2019	10.20%	2.47%	7.73%
12/19/2019	10.30%	2.47%	7.83%
12/20/2019	9.65%	2.47%	7.18%
12/20/2019	9.45%	2.47%	6.98%
12/24/2019	9.70%	2.46%	7.24%
1/8/2020	10.02%	2.43%	7.59%
1/16/2020	8.80%	2.41%	6.39%
1/22/2020	9.50%	2.39%	7.11%
1/23/2020	9.86%	2.39%	7.47%
2/6/2020	10.00%	2.35%	7.65%
2/11/2020	9.30%	2.33%	6.97%
2/14/2020	9.40%	2.32%	7.08%
2/19/2020	8.25%	2.31%	5.94%
2/24/2020	9.75%	2.30%	7.45%
2/27/2020	9.40%	2.28%	7.12%
3/11/2020	9.70%	2.23%	7.47%
3/25/2020	9.40%	2.17%	7.23%
4/17/2020	9.70%	2.07%	7.63%
4/27/2020	9.25%	2.03%	7.22%
5/8/2020	9.90%	1.97%	7.93%
5/20/2020	9.45%	1.94%	7.51%
6/29/2020	9.70%	1.85%	7.85%
6/30/2020	9.10%	1.85%	7.25%
7/1/2020	9.25%	1.84%	7.41%
7/8/2020	9.40%	1.83%	7.57%
7/14/2020	9.60%	1.81%	7.79%
7/28/2020	9.50%	1.77%	7.73%
8/27/2020	10.00%	1.66%	8.34%
8/27/2020	9.45%	1.66%	7.79%
8/27/2020	8.20%	1.66%	6.54%
10/22/2020	9.50%	1.50%	8.00%
10/28/2020	9.60%	1.48%	8.12%
11/19/2020	8.80%	1.45%	7.35%
11/19/2020	8.80%	1.45%	7.35%
11/24/2020	9.20%	1.44%	7.76%
11/24/2020	9.80%	1.44%	8.36%
12/9/2020	8.38%	1.43%	6.95%
12/9/2020	8.38%	1.43%	6.95%
12/10/2020	9.40%	1.43%	7.97%
12/14/2020	9.50%	1.44%	8.06%
12/15/2020	9.30%	1.44%	7.86%
12/16/2020	9.50%	1.44%	8.06%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/17/2020	9.90%	1.44%	8.46%
12/18/2020	9.50%	1.44%	8.06%
12/22/2020	9.15%	1.45%	7.70%
12/23/2020	10.00%	1.45%	8.55%
12/30/2020	9.65%	1.45%	8.20%
1/13/2021	9.30%	1.47%	7.83%
3/31/2021	9.60%	1.67%	7.93%
4/16/2021	9.60%	1.73%	7.87%
5/4/2021	9.85%	1.79%	8.06%
5/18/2021	9.50%	1.84%	7.66%
6/4/2021	9.28%	1.90%	7.38%
6/23/2021	9.00%	1.95%	7.05%
6/28/2021	9.55%	1.96%	7.59%
6/30/2021	9.43%	1.96%	7.47%
6/30/2021	9.43%	1.96%	7.47%
7/14/2021	9.60%	1.99%	7.61%
7/15/2021	9.38%	1.99%	7.39%
7/21/2021	9.50%	2.00%	7.50%
8/5/2021	9.60%	2.01%	7.59%
8/18/2021	9.50%	2.03%	7.47%
8/31/2021	8.57%	2.04%	6.53%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
9/1/2021	9.40%	2.04%	7.36%
9/27/2021	9.40%	2.07%	7.33%
10/21/2021	9.95%	2.10%	7.85%
10/26/2021	10.60%	2.10%	8.50%
10/28/2021	9.35%	2.10%	7.25%
11/2/2021	8.90%	2.11%	6.79%
11/4/2021	9.48%	2.11%	7.37%
11/17/2021	9.70%	2.11%	7.59%
11/18/2021	9.00%	2.11%	6.89%
11/18/2021	9.25%	2.11%	7.14%
11/18/2021	9.35%	2.11%	7.24%
11/18/2021	10.00%	2.11%	7.89%
11/18/2021	10.00%	2.11%	7.89%
11/23/2021	9.80%	2.11%	7.69%
12/1/2021	7.36%	2.10%	5.26%
12/7/2021	9.65%	2.09%	7.56%
12/13/2021	7.36%	2.08%	5.28%
12/15/2021	9.60%	2.08%	7.52%
12/22/2021	9.90%	2.06%	7.84%
12/28/2021	9.40%	2.05%	7.35%
1/20/2022	9.00%	2.03%	6.97%
2/16/2022	9.35%	2.02%	7.33%
2/23/2022	9.70%	2.02%	7.68%
3/16/2022	9.30%	2.02%	7.28%
4/14/2022	9.20%	2.07%	7.13%
4/25/2022	9.50%	2.11%	7.39%
5/12/2022	9.20%	2.18%	7.02%
5/23/2022	9.50%	2.22%	7.28%
8/31/2022	8.57%	2.64%	5.93%
9/8/2022	9.50%	2.69%	6.81%
9/15/2022	9.35%	2.73%	6.62%
10/4/2022	10.10%	2.85%	7.25%
10/4/2022	10.80%	2.85%	7.95%
10/25/2022	9.50%	2.99%	6.51%
11/3/2022	10.25%	3.06%	7.19%
11/3/2022	10.20%	3.06%	7.14%
11/3/2022	10.30%	3.06%	7.24%
11/17/2022	7.85%	3.16%	4.69%
11/18/2022	9.90%	3.17%	6.73%
11/30/2022	9.80%	3.23%	6.57%
12/1/2022	7.85%	3.23%	4.62%
12/14/2022	10.00%	3.29%	6.71%
12/14/2022	9.50%	3.29%	6.21%
12/14/2022	9.60%	3.29%	6.31%
12/15/2022	10.00%	3.30%	6.70%
12/15/2022	9.95%	3.30%	6.65%
12/15/2022	10.05%	3.30%	6.75%
12/16/2022	9.50%	3.30%	6.20%
12/20/2022	10.50%	3.32%	7.18%
12/22/2022	9.40%	3.33%	6.07%
12/22/2022	9.80%	3.33%	6.47%
12/27/2022	9.56%	3.35%	6.21%
12/29/2022	9.30%	3.36%	5.94%
12/29/2022	9.80%	3.36%	6.44%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/19/2023	9.90%	3.45%	6.45%
1/23/2023	9.65%	3.45%	6.20%
1/26/2023	9.75%	3.46%	6.29%
2/9/2023	9.60%	3.50%	6.10%
2/17/2023	9.50%	3.52%	5.98%
3/9/2023	9.70%	3.58%	6.12%
3/24/2023	9.90%	3.60%	6.30%
4/27/2023	10.00%	3.67%	6.33%
5/31/2023	9.35%	3.76%	5.59%
6/1/2023	9.25%	3.76%	5.49%
6/6/2023	9.75%	3.77%	5.98%
6/6/2023	9.35%	3.77%	5.58%
7/20/2023	9.25%	3.82%	5.43%
8/2/2023	9.80%	3.81%	5.99%
8/3/2023	9.57%	3.81%	5.76%
8/18/2023	9.80%	3.82%	5.98%
8/23/2023	9.58%	3.82%	5.76%
8/25/2023	9.55%	3.83%	5.72%
8/25/2023	8.63%	3.83%	4.80%
8/31/2023	11.45%	3.84%	7.61%
8/31/2023	9.40%	3.84%	5.56%
9/6/2023	9.30%	3.85%	5.45%
9/21/2023	9.65%	3.89%	5.76%
10/12/2023	9.20%	3.97%	5.23%
10/12/2023	9.20%	3.97%	5.23%
10/12/2023	9.75%	3.97%	5.78%
10/18/2023	9.50%	3.99%	5.51%
10/19/2023	9.50%	4.00%	5.50%
10/25/2023	9.65%	4.03%	5.62%
11/3/2023	9.30%	4.07%	5.23%
11/3/2023	9.70%	4.07%	5.63%
11/9/2023	9.80%	4.10%	5.70%
11/9/2023	9.80%	4.10%	5.70%
11/17/2023	9.60%	4.13%	5.47%
11/28/2023	9.35%	4.15%	5.20%
12/1/2023	9.90%	4.16%	5.74%
12/7/2023	9.70%	4.17%	5.53%
12/14/2023	8.91%	4.17%	4.74%
12/14/2023	8.72%	4.17%	4.55%
12/14/2023	10.00%	4.17%	5.83%
12/14/2023	9.50%	4.17%	5.33%
12/15/2023	10.10%	4.17%	5.93%
12/18/2023	9.50%	4.18%	5.32%
12/22/2023	10.70%	4.18%	6.52%
12/22/2023	10.65%	4.18%	6.47%
12/22/2023	10.75%	4.18%	6.57%
12/26/2023	9.52%	4.19%	5.33%
12/26/2023	9.52%	4.19%	5.33%
12/28/2023	9.60%	4.19%	5.41%
12/29/2023	9.60%	4.19%	5.41%
1/3/2024	9.26%	4.20%	5.06%
1/19/2024	9.75%	4.23%	5.52%
1/30/2024	9.75%	4.25%	5.50%
		# of Cases:	1,780

2024 - 2026 Planned Capital Expenditures as a Percentage of 2023 Net PP&E



Company	Ticker	Net PP&E ($000) 2023Y	Planned Capital Expenditures ($000) 2024Y	Planned Capital Expenditures ($000) 2025Y	Planned Capital Expenditures ($000) 2026Y	Total 2024-2026 Cap Ex as a % of 2023 Net PP&E	Rank
NorthWestern Energy Group, Inc.	NWE	6,039,801	500,000	506,000	463,000	24.32%	1
The Southern Company	SO	101,276,000	10,000,000	9,400,000	8,500,000	27.55%	2
Evergy, Inc.	EVRG	23,799,800	2,125,000	2,089,000	2,457,000	28.03%	3
Avista Corporation	AVA	5,837,868	521,000	535,000	587,000	28.14%	4
OGE Energy Corp.	OGE	10,952,300	1,100,000	1,150,000	1,200,000	31.50%	5
Pinnacle West Capital Corporation	PNW	19,023,022	1,950,000	2,000,000	2,050,000	31.54%	6
NextEra Energy, Inc.	NEE	126,612,000	17,405,000	11,970,000	10,570,000	31.55%	7
American Electric Power Company, Inc.	AEP	77,313,600	7,544,000	10,225,000	8,571,000	34.07%	8
Edison International	EIX	57,305,000	5,800,000	7,050,000	7,450,000	35.42%	9
Duke Energy Corporation	DUK	116,407,000	12,350,000	14,200,000	14,775,000	35.50%	10
Ameren Corporation	AEE	33,776,000	4,425,000	4,371,250	4,371,250	38.98%	11
Alliant Energy Corporation	LNT	17,157,000	2,275,000	1,980,000	2,435,000	38.99%	12
Portland General Electric Company	POR	9,189,000	1,310,000	1,200,000	1,150,000	39.83%	13
Entergy Corporation	ETR	44,252,875	5,920,000	6,500,000	7,335,000	44.64%	14
IDACORP, Inc.	IDA	5,745,230	950,000	900,000	750,000	45.25%	15
Xcel Energy Inc.	XEL	52,859,000	7,420,000	9,280,000	7,940,000	46.61%	16
CMS Energy Corporation	CMS	24,757,000	3,500,000	4,500,000	3,600,000	46.86%	17
Virginia Electric and Power Company [1]	DENC	44,260,000	9,400,000	7,600,000	6,900,000	54.00%	18
DTE Energy Company	DTE	27,788,000	4,695,000	5,251,250	5,251,250	54.69%	19
Proxy Group Median							35.46%
Proxy Group Average							36.82%

Source: S&P Capital IQ.
[1] Source for DENC's planned capital expenditures: Dominion Energy Inc. 2023 10-K, at p. 81 (2024); Dominion Energy Inc. Investor Presentation March 1, 2024, at slide 39 (2025-2026).

Proxy Group Regulatory Risk Comparative Assessment

				Adjustment Clauses							Ratemaking Framework Component		
Company	Parent	State (Jurisdiction)	Service	Fuel/ Purchased Power/Gas Commodity	Volumetric Risk Mitigation [1]	New Capital Investment [2]	Energy Efficiency [3]	Renewables & RPS [4]	Environmental [5]	Other [6]	Test Year	Rate Base Methodology	RRA Commission Ranking [7]
Ameren Illinois Company	AEE	Illinois	Electric	✓	✓	✓	✓	✓	✓	✓	Historical	Year End	Average / 3
Union Electric Company	AEE	Missouri	Electric	✓	✓	✓	✓	✓	✓	✓	Historical	Year End	Average / 3
Southwestern Electric Power Company	AEP	Arkansas	Electric	✓	✓	✓	✓		✓	✓	Historical	Year End	Average / 1
Indiana Michigan Power Company	AEP	Indiana	Electric	✓	✓	✓	✓	✓	✓	✓	Fully Forecast	Year End	Average / 1
Kentucky Power Company	AEP	Kentucky	Electric	✓	✓		✓	✓	✓	✓	Historical	Year End	Average / 2
Southwestern Electric Power Company	AEP	Louisiana	Electric	✓	✓	✓	✓	✓	✓	✓	Historical	Year End	Average / 3
Indiana Michigan Power Company	AEP	Michigan	Electric	✓	✓		✓	✓	✓	✓	Fully Forecast	Average	Above Average / 3
Ohio Power Company	AEP	Ohio	Electric	✓	✓	✓	✓	✓		✓	Partially Forecast	Year End	Average / 2
Public Service Company of Oklahoma	AEP	Oklahoma	Electric	✓	✓	✓	✓			✓	Historical	Year End	Average / 3
Kingsport Power Company	AEP	Tennessee	Electric	✓		✓				✓	Fully Forecast	Average	Above Average / 3
AEP Texas Inc.	AEP	Texas	Electric	NA		✓	✓		✓	✓	Historical	Year End	Average / 3
Southwestern Electric Power Company	AEP	Texas	Electric	✓		✓	✓	✓		✓	Historical	Year End	Average / 3
Appalachian Power Company	AEP	Virginia	Electric	✓		✓	✓	✓	✓	✓	Fully Forecast	Year End	Average / 2
Appalachian Power / Wheeling Power	AEP	West Virginia	Electric	✓		✓	✓	✓	✓	✓	Historical	Average	Below Average / 1
Alaska Electric Light and Power Company	AVA	Alaska	Electric	✓						✓	Historical	Average	Below Average / 1
Avista Corporation	AVA	Idaho	Electric	✓	✓		✓			✓	Historical	Average	Average / 2
Avista Corporation	AVA	Washington	Electric	✓	✓	✓	✓			✓	Historical	Average	Average / 3
Consumers Energy Company	CMS	Michigan	Electric	✓			✓	✓		✓	Fully Forecast	Average	Above Average / 3
DTE Electric Company	DTE	Michigan	Electric	✓		✓	✓	✓	✓	✓	Fully Forecast	Average	Above Average / 3
Duke Energy Florida, LLC	DUK	Florida	Electric	✓		✓	✓	✓	✓	✓	Fully Forecast	Average	Above Average / 2
Duke Energy Indiana, LLC	DUK	Indiana	Electric	✓	✓	✓	✓	✓	✓	✓	Fully Forecast	Year End	Average / 1
Duke Energy Kentucky, Inc.	DUK	Kentucky	Electric	✓	✓		✓		✓	✓	Fully Forecast	Average	Average / 2
Duke Energy Carolinas, LLC	DUK	North Carolina	Electric	✓	✓		✓	✓	✓	✓	Historical	Year End	Above Average / 3
Duke Energy Progress, LLC	DUK	North Carolina	Electric	✓	✓	✓	✓	✓	✓	✓	Historical	Year End	Above Average / 3
Duke Energy Ohio, Inc.	DUK	Ohio	Electric	✓	✓	✓	✓	✓		✓	Partially Forecast	Year End	Average / 2
Duke Energy Carolinas, LLC	DUK	South Carolina	Electric	✓	✓		✓	✓	✓	✓	Historical	Year End	Average / 3
Duke Energy Progress, LLC	DUK	South Carolina	Electric	✓	✓		✓	✓	✓	✓	Historical	Year End	Average / 3
Southern California Edison Company	EIX	California	Electric	✓	✓		✓		✓	✓	Fully Forecast	Average	Average / 1
Entergy Arkansas, LLC	ETR	Arkansas	Electric	✓	✓	✓	✓		✓	✓	Fully Forecast	Average	Average / 1
Entergy Louisiana, LLC	ETR	Louisiana	Electric	✓	✓	✓	✓		✓	✓	Historical	Average	Average / 3
Entergy Mississippi, LLC	ETR	Mississippi	Electric	✓	✓	✓	✓		✓	✓	Partially Forecast	Average	Above Average / 3
Entergy New Orleans, LLC	ETR	Louisiana - NOCC	Electric	✓	✓	✓	✓		✓	✓	Partially Forecast	Year End	Average / 3
Entergy Texas, Inc.	ETR	Texas	Electric	✓		✓	✓			✓	Fully Forecast	Year End	Average / 3
Evergy Kansas Central	EVRG	Kansas	Electric	✓	✓		✓		✓	✓	Historical	Year End	Below Average / 1
Evergy Kansas Metro	EVRG	Kansas	Electric	✓			✓		✓	✓	Historical	Year End	Below Average / 1
Evergy Missouri Metro	EVRG	Missouri	Electric	✓	✓	✓	✓		✓	✓	Historical	Year End	Average / 3
Evergy Missouri West	EVRG	Missouri	Electric	✓	✓	✓	✓	✓	✓	✓	Historical	Year End	Average / 3
Idaho Power Co.	IDA	Idaho	Electric	✓	✓		✓			✓	Partially Forecast	Average	Average / 2
Idaho Power Co.	IDA	Oregon	Electric	✓			✓	✓	✓	✓	Fully Forecast	Average	Average / 2
Interstate Power and Light Company	LNT	Iowa	Electric	✓		✓	✓	✓	✓	✓	Fully Forecast	Average	Above Average / 3
Wisconsin Power and Light Company	LNT	Wisconsin	Electric	✓						✓	Fully Forecast	Average	Above Average / 3
Florida Power & Light Company	NEE	Florida	Electric	✓		✓	✓	✓	✓	✓	Fully Forecast	Average	Above Average / 2
NorthWestern Energy	NWE	Montana	Electric	✓			✓			✓	Historical	Average	Below Average / 1
NorthWestern Energy	NWE	South Dakota	Electric	✓	✓				✓	✓	Historical	Average	Average / 2
Oklahoma Gas and Electric Company	OGE	Arkansas	Electric	✓	✓	✓	✓		✓	✓	Historical	Year End	Average / 1
Oklahoma Gas and Electric Company	OGE	Oklahoma	Electric	✓	✓	✓	✓			✓	Historical	Year End	Average / 3
Arizona Public Service Company	PNW	Arizona	Electric	✓	✓	✓	✓	✓	✓	✓	Historical	Year End	Below Average / 3
Portland General Electric Company	POR	Oregon	Electric	✓	✓	✓	✓	✓	✓	✓	Fully Forecast	Average	Average / 2
Alabama Power Company	SO	Alabama	Electric	✓	✓	✓			✓	✓	Fully Forecast	Year End	Above Average / 1
Georgia Power Company	SO	Georgia	Electric	✓	✓	✓	✓		✓	✓	Fully Forecast	Average	Above Average / 2
Mississippi Power Company	SO	Mississippi	Electric	✓	✓	✓	✓	✓	✓	✓	Fully Forecast	Year End	Above Average / 3
Public Service Company of Colorado	XEL	Colorado	Electric	✓	✓	✓	✓	✓	✓	✓	Historical	Year End	Average / 1
Northern States Power Company - WI	XEL	Michigan	Electric	✓				✓		✓	Fully Forecast	Average	Above Average / 3
Northern States Power Company - MN	XEL	Minnesota	Electric	✓	✓	✓	✓	✓	✓	✓	Fully Forecast	Average	Average / 2
Southwestern Public Service Company	XEL	New Mexico	Electric	✓		✓	✓	✓		✓	Fully Forecast	Average	Below Average / 1
Northern States Power Company - MN	XEL	North Dakota	Electric	✓		✓		✓		✓	Fully Forecast	Average	Average / 1
Northern States Power Company - MN	XEL	South Dakota	Electric	✓	✓	✓	✓		✓	✓	Historical	Average	Average / 2
Southwestern Public Service Company	XEL	Texas	Electric	✓		✓	✓			✓	Historical	Year End	Average / 3
Northern States Power Company - WI	XEL	Wisconsin	Electric	✓						✓	Fully Forecast	Average	Above Average / 3
		% of Proxy Group		100%	64%	68%	86%	53%	68%	100%	51%	51%	41%
											% Partial or Fully Forecast	*% Year End Rate Base*	*% jurisdictions rated better than Average/2*
Virginia Electric and Power Company	D	North Carolina	Electric	✓	✓		✓	✓	✓		Historical	Year End	Above Average / 3
Virginia Electric and Power Company	D	Virginia	Electric	✓		✓	✓	✓	✓	✓	Fully Forecast	Year End	Average / 2

Notes:

A mechanism may cover one or more cost categories; therefore, designations may not indicate separate mechanisms for each category. Texas T&D electric utilities do not have retail obligation, thus do not need a fuel or purchased power cost recovery mechanism.

[1] Volumetric Risk Mitigation mechanisms include full or partial decoupling, straight fixed variable rate design, weather normalization adjustment clauses, recovery of lost revenues as a result of Energy Efficiency programs, and earnings true-up mechanisms, such as formula rate plans or annual rate review riders.

[2] Includes recovery of costs related to targeted new generation projects, transmission capital, infrastructure replacement, system integrity/hardening, Smart Grid, AMI metering, and other capital expenditures.

[3] Utility-sponsored conservation, energy efficiency, load control, or other demand side management programs.

[4] Recovers costs associated with renewable energy projects, distributed energy resources, REC purchases, net metering, RPS expense, and renewable PPAs.

[5] EPA upgrade costs, emissions control & allowance purchase costs, nuclear/coal plant decommissioning, and other costs to comply with state and federal environmental mandates.

[6] Cost recovery for items such as pension expenses, bad debt costs, low income programs, storm costs, vegetation management, RTO/transmission expense (not capital), government & franchise fees and taxes, and regulatory fees.

[7] RRA maintains three principal rating categories, Above Average, Average, and Below Average, with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint, and Below Average indicating a less constructive, higher-risk regulatory climate from an investor viewpoint, Within the three principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger (more constructive) rating; 2, a mid range rating; and, 3, a weaker (less constructive) rating. We endeavor to maintain an approximately equal number of ratings above the average and below the average.

Sources: Alternative Ratemaking Plans in the U.S., Regulatory Research Associates, April 16, 2020; Regulatory Research Associates, Adjustment Clauses: A State-by-State Overview, July 18, 2022; ACEEE Utility Business Model Database; Regulatory Research Associates Commission Profiles; SEC Form 10-Ks; Company Tariffs.

Capital Structure Analysis

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	Average
Alliant Energy Corporation	LNT	52.60%	51.32%	52.51%	52.14%
Ameren Corporation	AEE	53.66%	53.72%	53.09%	53.49%
American Electric Power Company, Inc.	AEP	48.56%	47.76%	48.15%	48.16%
Avista Corporation	AVA	51.06%	50.79%	50.99%	50.95%
CMS Energy Corporation	CMS	49.78%	52.28%	51.17%	51.07%
DTE Energy Company	DTE	50.41%	49.83%	49.45%	49.90%
Duke Energy Corporation	DUK	53.04%	53.39%	52.95%	53.13%
Edison International	EIX	42.40%	45.52%	49.10%	45.67%
Entergy Corporation	ETR	45.48%	46.32%	48.14%	46.65%
Evergy, Inc.	EVRG	63.11%	62.87%	61.64%	62.54%
IDACORP, Inc.	IDA	54.37%	55.00%	53.96%	54.44%
NextEra Energy, Inc.	NEE	63.14%	62.12%	60.04%	61.77%
NorthWestern Energy Group, Inc.	NWE	50.34%	47.82%	47.17%	48.44%
OGE Energy Corporation	OGE	55.65%	53.38%	53.04%	54.02%
Pinnacle West Capital Corporation	PNW	50.25%	51.12%	51.35%	50.91%
Portland General Electric Company	POR	43.24%	45.09%	46.07%	44.80%
Southern Company	SO	54.58%	54.38%	54.66%	54.54%
Xcel Energy Inc.	XEL	54.84%	54.41%	54.82%	54.69%

Proxy Group					
MEAN		52.03%	52.06%	52.13%	52.07%
MEDIAN		51.83%	51.80%	51.93%	51.61%
MIDPOINT					53.67%
LOW		42.40%	45.09%	46.07%	44.80%
HIGH		63.14%	62.87%	61.64%	62.54%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2022	2021	2020	Average
Interstate Power and Light Company	LNT	50.55%	50.22%	52.34%	51.04%
Wisconsin Power and Light Company	LNT	55.03%	52.86%	52.78%	53.56%
Ameren Illinois Company	AEE	55.63%	55.78%	55.18%	55.53%
Union Electric Company	AEE	51.88%	51.87%	51.22%	51.66%
AEP Texas Inc.	AEP	42.07%	42.81%	42.41%	42.43%
Appalachian Power Company	AEP	47.76%	48.34%	47.19%	47.76%
Indiana Michigan Power Company	AEP	49.29%	47.38%	48.67%	48.44%
Kentucky Power Company	AEP	43.82%	44.17%	45.28%	44.42%
Kingsport Power Company	AEP	53.89%	54.18%	53.42%	53.83%
Ohio Power Company	AEP	50.79%	48.76%	52.42%	50.66%
Public Service Company of Oklahoma	AEP	55.70%	54.36%	52.88%	54.31%
Southwestern Electric Power Company	AEP	52.54%	48.70%	50.78%	50.67%
Wheeling Power Company	AEP	49.14%	54.01%	54.10%	52.42%
Avista Corporation	AVA	50.65%	50.35%	50.57%	50.52%
Alaska Electric Light and Power Company	AVA	60.89%	60.49%	60.15%	60.51%
Consumers Energy Company	CMS	49.78%	52.28%	51.17%	51.07%
DTE Electric Company	DTE	50.41%	49.83%	49.45%	49.90%
Duke Energy Carolinas, LLC	DUK	52.78%	52.05%	52.33%	52.39%
Duke Energy Florida, LLC	DUK	50.74%	52.65%	52.59%	51.99%
Duke Energy Indiana, LLC	DUK	52.06%	53.56%	53.74%	53.12%
Duke Energy Kentucky, Inc.	DUK	52.97%	52.90%	49.54%	51.80%
Duke Energy Ohio, Inc.	DUK	65.87%	64.40%	62.46%	64.24%
Duke Energy Progress, LLC	DUK	51.27%	51.76%	50.69%	51.24%
Southern California Edison Company	EIX	42.40%	45.52%	49.10%	45.67%
Entergy Arkansas, LLC	ETR	47.84%	45.94%	47.90%	47.23%
Entergy Louisiana, LLC	ETR	43.08%	45.62%	47.47%	45.39%
Entergy Mississippi, LLC	ETR	45.53%	48.19%	48.60%	47.44%
Entergy New Orleans, LLC	ETR	45.52%	50.04%	49.26%	48.27%
Entergy Texas, Inc.	ETR	51.32%	47.05%	50.43%	49.60%
Evergy Kansas Central, Inc.	EVRG	67.13%	67.00%	65.93%	66.69%
Evergy Kansas South, Inc.	EVRG	NA	NA	NA	NA
Evergy Metro, Inc.	EVRG	52.03%	51.36%	48.69%	50.69%
Evergy Missouri West, Inc.	EVRG	54.41%	52.01%	51.97%	52.80%
Westar Energy (KPL)	EVRG	58.03%	58.52%	57.03%	57.86%
Idaho Power Company	IDA	54.37%	55.00%	53.96%	54.44%
Florida Power & Light Company	NEE	63.14%	62.12%	60.04%	61.77%
NorthWestern Corporation	NWE	50.34%	47.82%	47.17%	48.44%
Oklahoma Gas and Electric Company	OGE	55.65%	53.38%	53.04%	54.02%
Arizona Public Service Company	PNW	50.25%	51.12%	51.35%	50.91%
Portland General Electric Company	POR	43.24%	45.09%	46.07%	44.80%
Alabama Power Company	SO	52.22%	52.36%	52.37%	52.31%
Georgia Power Company	SO	56.05%	55.60%	56.05%	55.90%
Mississippi Power Company	SO	55.67%	55.40%	55.31%	55.46%
Northern States Power Company	XEL	52.79%	52.65%	53.19%	52.88%
Northern States Power Company	XEL	52.79%	52.65%	53.19%	52.88%
Public Service Company of Colorado	XEL	57.18%	56.44%	56.82%	56.81%
Southwestern Public Service Company	XEL	54.30%	54.23%	54.17%	54.23%
Operating Company					
MEAN		52.19%	52.15%	52.18%	52.17%
MEDIAN		52.04%	52.17%	52.33%	51.90%
LOW		42.07%	42.81%	42.41%	42.43%
HIGH		67.13%	67.00%	65.93%	66.69%

Notes:

Sources: Operating Company FERC Form 1; S&P Capital IQ

[1] Ratios are weighted by actual common equity and total long-term debt of operating subsidiaries.

[2] Evergy Kansas South was removed because it is financed with more than 80% common equity

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	Average
Alliant Energy Corporation	LNT	47.40%	48.68%	47.49%	47.86%
Ameren Corporation	AEE	46.34%	46.28%	46.91%	46.51%
American Electric Power Company, Inc.	AEP	51.44%	52.24%	51.85%	51.84%
Avista Corporation	AVA	48.94%	49.21%	49.01%	49.05%
CMS Energy Corporation	CMS	50.22%	47.72%	48.83%	48.93%
DTE Energy Company	DTE	49.59%	50.17%	50.55%	50.10%
Duke Energy Corporation	DUK	46.96%	46.61%	47.05%	46.87%
Edison International	EIX	57.60%	54.48%	50.90%	54.33%
Entergy Corporation	ETR	54.52%	53.68%	51.86%	53.35%
Evergy, Inc.	EVRG	36.89%	37.13%	38.36%	37.46%
IDACORP, Inc.	IDA	45.63%	45.00%	46.04%	45.56%
NextEra Energy, Inc.	NEE	36.86%	37.88%	39.96%	38.23%
NorthWestern Energy Group, Inc.	NWE	49.66%	52.18%	52.83%	51.56%
OGE Energy Corporation	OGE	44.35%	46.62%	46.96%	45.98%
Pinnacle West Capital Corporation	PNW	49.75%	48.88%	48.65%	49.09%
Portland General Electric Company	POR	56.76%	54.91%	53.93%	55.20%
Southern Company	SO	45.42%	45.62%	45.34%	45.46%
Xcel Energy Inc.	XEL	45.16%	45.59%	45.18%	45.31%

Proxy Group					
MEAN		47.97%	47.94%	47.87%	47.93%
MEDIAN		48.17%	48.20%	48.07%	48.39%
MIDPOINT					46.33%
LOW		36.86%	37.13%	38.36%	37.46%
HIGH		57.60%	54.91%	53.93%	55.20%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2022	2021	2020	Average
Interstate Power and Light Company	LNT	49.45%	49.78%	47.66%	48.96%
Wisconsin Power and Light Company	LNT	44.97%	47.14%	47.22%	46.44%
Ameren Illinois Company	AEE	44.37%	44.22%	44.82%	44.47%
Union Electric Company	AEE	48.12%	48.13%	48.78%	48.34%
AEP Texas Inc.	AEP	57.93%	57.19%	57.59%	57.57%
Northern Indiana Public Service Company	NI	52.24%	51.66%	52.81%	52.24%
Indiana Michigan Power Company	AEP	50.71%	52.62%	51.33%	51.56%
Kentucky Power Company	AEP	56.18%	55.83%	54.72%	55.58%
Kingsport Power Company	AEP	46.11%	45.82%	46.58%	46.17%
Ohio Power Company	AEP	49.21%	51.24%	47.58%	49.34%
Public Service Company of Oklahoma	AEP	44.30%	45.64%	47.12%	45.69%
Southwestern Electric Power Company	AEP	47.46%	51.30%	49.22%	49.33%
Wheeling Power Company	AEP	50.86%	45.99%	45.90%	47.58%
Avista Corporation	AVA	49.35%	49.65%	49.43%	49.48%
Alaska Electric Light and Power Company	AVA	39.11%	39.51%	39.85%	39.49%
Consumers Energy Company	CMS	50.22%	47.72%	48.83%	48.93%
DTE Electric Company	DTE	49.59%	50.17%	50.55%	50.10%
Duke Energy Carolinas, LLC	DUK	47.22%	47.95%	47.67%	47.61%
Duke Energy Florida, LLC	DUK	49.26%	47.35%	47.41%	48.01%
Duke Energy Indiana, LLC	DUK	47.94%	46.44%	46.26%	46.88%
Duke Energy Kentucky, Inc.	DUK	47.03%	47.10%	50.46%	48.20%
Duke Energy Ohio, Inc.	DUK	34.13%	35.60%	37.54%	35.76%
Northern Indiana Public Service Company	DUK	48.73%	48.24%	49.31%	48.76%
Southern California Edison Company	EIX	57.60%	54.48%	50.90%	54.33%
Entergy Arkansas, LLC	ETR	52.16%	54.06%	52.10%	52.77%
Entergy Louisiana, LLC	ETR	56.92%	54.38%	52.53%	54.61%
Entergy Mississippi, LLC	ETR	54.47%	51.81%	51.40%	52.56%
Entergy New Orleans, LLC	ETR	54.48%	49.96%	50.74%	51.73%
Entergy Texas, Inc.	ETR	48.68%	52.95%	49.57%	50.40%
Evergy Kansas Central, Inc.	EVRG	32.87%	33.00%	34.07%	33.31%
Evergy Kansas South, Inc.	EVRG	NA	NA	NA	NA
Evergy Metro, Inc.	EVRG	47.97%	48.64%	51.31%	49.31%
Evergy Missouri West, Inc.	EVRG	45.59%	47.99%	48.03%	47.20%
Westar Energy (KPL)	EVRG	41.97%	41.48%	42.97%	42.14%
Idaho Power Company	IDA	45.63%	45.00%	46.04%	45.56%
Florida Power & Light Company	NEE	36.86%	37.88%	39.96%	38.23%
NorthWestern Corporation	NWE	49.66%	52.18%	52.83%	51.56%
Oklahoma Gas and Electric Company	OGE	44.35%	46.62%	46.96%	45.98%
Arizona Public Service Company	PNW	49.75%	48.88%	48.65%	49.09%
Portland General Electric Company	POR	56.76%	54.91%	53.93%	55.20%
Alabama Power Company	SO	47.78%	47.64%	47.63%	47.69%
Georgia Power Company	SO	43.95%	44.40%	43.95%	44.10%
Mississippi Power Company	SO	44.33%	44.60%	44.69%	44.54%
Northern States Power Company	XEL	47.21%	47.35%	46.81%	47.12%
Northern States Power Company	XEL	47.21%	47.35%	46.81%	47.12%
Public Service Company of Colorado	XEL	42.82%	43.56%	43.18%	43.19%
Southwestern Public Service Company	XEL	45.70%	45.77%	45.83%	45.77%

Operating Company					
MEAN		47.81%	47.85%	47.82%	47.83%
MEDIAN		47.96%	47.83%	47.67%	48.10%
LOW		32.87%	33.00%	34.07%	33.31%
HIGH		57.93%	57.19%	57.59%	57.57%

Notes:

Sources: Operating Company FERC Form 1; S&P Capital IQ

[1] Ratios are weighted by actual common equity and total long-term debt of operating subsidiaries.

[2] Evergy Kansas South was removed because it is financed with more than 80% common equity

**DIRECT TESTIMONY
OF
JEFFREY G. MISCIKOWSKI
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 694**

Q. Please state your name, position of employment, and business address.

A. My name is Jeffrey G. Miscikowski, and I am Vice President, Project Construction for Dominion Energy Services, Inc., testifying on behalf of Virginia Electric and Power Company, which does business in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company"). My business address is 600 East Canal Street, Richmond, Virginia 23219.

Q. Please describe your area of responsibility within the Company.

A. As Vice President of Project Construction, I am responsible for the engineering and construction of major capital projects, including both new and existing facilities planned by Dominion Energy North Carolina and its affiliates. A statement of my background and qualifications is attached as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes, I testified before the Commission in Docket No. E-22, Sub 510.

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

A. My testimony supports the Company's overall request to adjust North Carolina base rates to recover the cost of providing reliable electric service to its North Carolina customers. Specifically, I will (1) discuss the Company's expanding solar footprint, battery storage efforts, and offshore wind development, (2) provide an update on permitting and work associated with the Company's nuclear assets as well as work performed associated with the Company's fossil units that the Company has made since the previous rate case in Docket No. E-22, Sub 562 ("2019 Rate Case"), and (3) describe the benefits to DENC's customers resulting from those investments, and (4) explain the Company's major investments in coal ash remediation as required by federal and state law.

Q. Mr. Miscikowski, how is your testimony organized?

A. My direct testimony is organized as follows:

I. Solar, Battery Storage, and Offshore Wind Generation

II. Nuclear Generation and Subsequent License Renewal

III. Fossil Generation

IV. Coal Combustion Residual ("CCR") Remediation

I. SOLAR, BATTERY STORAGE, AND OFFSHORE WIND GENERATION

Q. Please provide an overview of the Virginia Clean Economy Act as it relates to solar, battery storage, and offshore wind generation.

A. The Virginia Clean Economy Act of 2020 ("VCEA") requires the development of significant renewable energy generation and energy storage resources by the Company. The development of new renewable energy generation is needed to comply with the mandatory renewable energy portfolio standard program (the "RPS Program") also established through the VCEA, while the development of energy storage resources is needed to ensure system reliability and enhance system performance.

Specifically, the Company must seek the necessary approvals to construct or purchase 16,100 MW of solar or onshore wind generation located in Virginia by 2035, including at least 3,000 MW of the 16,100 MW by 2024, with 35% of that capacity purchased from third party-owned facilities through PPAs. The Company must also petition for the necessary approvals to construct or acquire 2,700 MW of energy storage capacity by 2035, with the goal of installing at least 10% behind the meter, and including 250 MW of the 2,700 MW by 2025. At least 35% of energy storage facilities placed into service must be purchased from a third party or owned by a third party with capacity sold to the Company through PPAs. Finally, the VCEA found construction of at least 2,500 MW of offshore wind facilities that are utility-owned and -operated to be in the public interest.

A. Solar Generation

Q. Please provide an overview of the Company's solar generation fleet.

A. The Company's regulated solar fleet consists of thirteen facilities with capacities ranging from 1.6 MWac to 142 MWac with a total generating capacity for the fleet of approximately 600 MWac.

Q. Please discuss the investments in solar generation that the Company has made since the 2019 Rate Case.

A. Since the 2019 Rate Case, the Company has placed 10 solar generation facilities in service through the end of 2023 (Colonial Trail West, Spring Grove 1, Sadler, Grassfield, Sycamore Creek, Piney Creek, Solidago, Norge, Black Bear, and Winterberry). In total, this represents approximately $1 billion of capital investments in renewable solar generation, which have resulted in approximately 544 MW of system resource capacity that is producing clean, efficient electric power today for customers across DENC's system.

In addition to the units that have been placed in-service, the Company has either received approval for, or is actively seeking approval to construct, approximately 25 additional solar and distributed solar facilities representing 1,362 MWac of generating capacity.

Q. What were the total construction costs for these 10 solar projects?

A. The costs associated with the ten projects placed in service since 2019 are approximately $1 billion dollars on a system basis. Collectively, all ten projects came in on time and at or under budget. This is a direct result of the Company's judicious oversight and management of these projects.

B. Battery Storage

Q. Please discuss the Company's purpose in constructing battery energy storage facilities.

A. Battery Energy Storage Systems ("BESS") play a critical role in the Company's goal of achieving net zero carbon emissions by supporting its growing portfolio of renewable generation. Energy storage improves grid reliability during peak demand hours and can help offset periods of lower generation caused by the intermittency of solar and wind energy. As the Company's overall renewable generation capabilities increase, BESS installations are increasingly important in ensuring reliable delivery of power to customers.

Q. Please discuss the investments in BESS facilities that the Company has made since the 2019 Rate Case.

A. Since the 2019 Rate Case, the Company has brought online the BESS-1, BESS-2, Scott-I BESS ("BESS-3") and the Dry Bridge BESS facilities. These facilities range in capacity from 2 MW/4 MWh (meaning having the capability to deliver a maximum of 2 MW of power for 2 hours) to 20 MW/80 MWh and represent a total capital investment of approximately $73 million.

C. Offshore Wind

Q. Please describe the Company's offshore wind generation facilities.

A. The Coastal Virginia Offshore Wind ("CVOW") Pilot Project consists of two 6 MW wind turbine generators ("WTGs") and is located approximately 27 miles off the coast of Virginia Beach in federal waters. The project achieved commercial operations on January 11, 2021, coming in on time and under budget. The project totaled approximately $295 million dollars and has been informative for the Company's 2,560 MW (nominal) CVOW Commercial Project, which will involve the construction of 176 WTGs and will also be located 27 miles off the cost of Virginia Beach ("CVOW Commercial Project"). The CVOW Pilot has also exceeded its original capacity factor expectations and is now providing electric generation to meet customer needs.

Q. Please discuss further the benefits of the CVOW Pilot Project.

A. The insights derived from the CVOW Pilot Project were varied and spanned the full spectrum of the Pilot from its development through commercial operations and maintenance activities. Specifically, as a result of the Company's experience with the development and installation of the CVOW Pilot Project WTGs, the Company has acquired valuable knowledge related to managing the inherent risks associated with working in an offshore environment. The Company will leverage this experience and knowledge, including in the areas of safety, environmental, cyber security, permitting, construction, commissioning, and operations & maintenance, as it moves forward with all phases of the CVOW Commercial Project.

For example, from a safety perspective, the U.S. Bureau of Safety and Environmental Enforcement ("BSEE") requires a Safety Management System ("SMS") to manage certain activities for this type of project, including: (i) hazard identification; (ii) risk management and control measures; and (iii) protection of employees, contractors and the public, to identify and mitigate hazards associated with the activities undertaken by employees on the site. The CVOW Pilot SMS was the first of its kind to be reviewed and approved by both Bureau of Ocean Energy Management ("BOEM") and BSEE in the U.S. offshore wind industry. The Company is expanding the SMS from the Pilot to meet requirements for the Commercial Project with respect to marine coordination and continued coordination with the U.S. Coast Guard.

Q. Please briefly address the status of the CVOW Commercial Project.

A. The CVOW Commercial Project is proceeding on time and on budget, largely consistent with the Company's timelines and estimates. The total project forecast remains approximately $9.8 billion. Issuance of final permits is expected to occur in early 2024, with onshore and offshore construction commencing shortly thereafter. On February 22, 2024, the Company announced an agreement, subject to required regulatory approvals, to sell a 50% noncontrolling interest in the CVOW Commercial Project to Stonepeak, a leading global infrastructure investor, through the formation of an offshore wind partnership. Under the proposed arrangement, the Company will retain full operational control of the construction and operations of the project.

II. NUCLEAR GENERATION AND SLR

Q. Please provide an overview of the Company's nuclear fleet.

A. The Company's nuclear fleet consists of two generating stations, North Anna and Surry Power Stations ("Nuclear Fleet") with a total generating capacity of approximately 3,568 total megawatts ("MW"), composed of:

North Anna - 1,892 MW (88.4% ownership); and

Surry - 1,676 MW.

The North Anna and Surry Power Stations are both pressurized water reactor facilities with two units each.

Q. Have any major changes in capacity occurred within the fleet since the 2019 Rate Case?

A. No.

Q. Please provide more detail on the Company's investments in its nuclear fleet.

A. The Company has invested over $480 million in its nuclear fleet since 2019, in addition to the investments in Subsequent License Renewal ("SLR") projects that I discuss further below. This base investment in the nuclear fleet ensures safe, reliable, and efficient electric generation to support nuclear power as a fundamental component of the Company's transition to net zero emissions and a necessary resource to maintain reliability and affordability. Examples of investment projects include turbine control upgrades, fire protection pipe replacement, thermal shield flexure replacement and circulating water pump refurbishments at Surry Power Station and plant computer system replacement, reserve station transformer replacement and reactor coolant pump seal replacements at North Anna Power Station.

Q. Please provide an update on SLR for the Company's nuclear fleet.

A. Surry Power Station Units 1 and 2 began commercial operation in 1972 and 1973, respectively. Surry's units were originally licensed to operate for 40 years and then were renewed for an additional 20 years. In 2003, the operating licenses for Units 1 and 2 were renewed by the Nuclear Regulatory Commission ("NRC"), extending operations up to 2032 and 2033, respectively. In 2021, the NRC approved a subsequent license renewal for Surry Power Station further extending operations by another 20 years to 2052 and 2053 for Units 1 and 2, respectively. It is worth noting that Surry is the only nuclear plant in the United States to be licensed for 80 years.

North Anna Power Station Unit 1 and Unit 2 began commercial operation in 1978 and 1980, respectively. The operating licenses for North Anna Power Station were renewed by the NRC in 2003, extending operations up to 2038 and 2040 for Units 1 and 2, respectively. In 2020, the Company submitted an SLR application to the NRC to extend the operating license of North Anna Power Station by 20 additional years. Approval of this application by the NRC is expected in 2024.

Q. Please provide a high-level overview of the projects necessary to operate Surry and North Anna during the period of extended operation.

A. The upgrades at both Surry and North Anna that are required to operate these stations through extended license renewal are extensive. These projects include, for example, upgrades to digital instrumentation and controls and refurbishment of reactor coolant pumps. The Company has successfully leveraged experience with projects at Surry to improve efficiency of the same projects at North Anna. The Company has invested approximately $985 million in SLR projects since 2019.

III. FOSSIL GENERATION

Q. Please provide an overview of the Company's fossil stations.

A. The Company's coal fleet comprises three stations (Mt. Storm, Virginia City Hybrid Energy Center or VCHEC, and Clover) with a total generating capacity of 2,666 MW. The natural gas fleet includes seven combined cycle stations (Greensville County, Brunswick County, Warren County, Bear Garden, Possum Point, Chesterfield, and Gordonsville Energy) and five combustion turbine stations (Ladysmith, Remington, Elizabeth River, Gravel Neck, and Darbytown) with a combined total generating capacity of 8,195 MW. The Company also has oil capability totaling 727 MW at seven stations

(Gravel Neck, Darbytown, Rosemary, Possum Point, Low Moor, Northern Neck, and Chesapeake).

Q. Please discuss the investments in fossil assets that the Company has made since the 2019 Rate Case.

A. Since July 1, 2019, the Company has performed maintenance capital and environmental compliance projects at its coal and natural gas stations to maintain reliability and efficiency of these units for the benefit of customers and to comply with regulatory requirements.

Most of the work done on the combined cycle and combustion turbine fleet was conducted during planned outages and involved, for example, disassembly of the combustion turbines and replacement of turbine parts including combustion, rotating, and stationary components.

For the coal fleet, the Company's major investment during this period was the conversion of the Mount Storm Power Station's bottom ash transport system from a wet open loop to a dry closed loop transport system to comply with the Federal Effluent Limitations Guidelines (ELG rule), which went in service in December 2023.

IV. CCR REMEDIATION

Q. Please provide some background on the Company's CCR and related remediation projects.

A. Coal Combustion Residuals or "CCR" as used in my testimony, is defined consistent with that term's definition in Virginia 2019 SB 1355 (the "Virginia

CCR Statute"), which I discuss further below: "fly ash, bottom ash, boiler slag, and flue gas desulfurization materials generated from burning coal for the purpose of generating electricity by an electric utility."

The Company stores CCR in ponds and/or landfills at the Bremo Power Station, Chesterfield Power Station, Possum Point Power Station, and the Chesapeake Energy Center (collectively, the "Power Stations"). Among these Power Stations, there is approximately 27 million cubic yards of stored CCR, broken down as follows:

Power Station	**Stored CCR Volume** *(rounded to nearest 1M)*
Bremo Power Station	6M cubic yards
Chesterfield Power Station	15M cubic yards
Possum Point Power Station	4M cubic yards
Chesapeake Energy Center	2M cubic yards
Total	27M cubic yards

As noted by Company Witness Baine, state and federal laws and regulations impose requirements on the Company's management and disposal of CCRs at certain of its coal-fired power plants. In general, the EPA's 2015 CCR Rule ("Federal CCR Rule") requires an owner/operator of an existing CCR surface impoundment unit to close the unit under certain circumstances and in certain ways. Prior to enactment of the Virginia CCR Statute in 2019, the Company initially planned to cap and close in place the CCR storage facilities at the Power Stations, consistent with federal and state regulations. Specifically, the Company's closure in place (or cap in place) plans entailed dewatering ash basins, regarding the ash in the basins as necessary, and installing an impervious cap to cover each basin (after consolidation of ash into a single basin footprint at Bremo and Possum Point).

With the enactment of the Virginia CCR Statute in 2019, the Company revised its methodologies to be in compliance with the requirements of the new law and established Rider CCR for the recovery of these costs in Virginia.

Q. Please provide an overview of the requirements imposed by the Virginia CCR Statute.

A. On March 19, 2019, the Virginia General Assembly passed SB 1355 (the "Virginia CCR Statute"), which became effective on July 1, 2019, and requires the Company to remove all CCR from the current pond storage locations at the Company's Power Stations and either beneficially reuse it or move it to a qualified landfill (onsite or offsite). Specifically, the Virginia CCR Statute requires the Company to:

(i) remove all CCR from the applicable storage units at each Power Station in accordance with applicable standards established by the Virginia Solid Waste Management Regulations (9 VAC 20-81-10 *et seq.*) and either (a) beneficially reuse such CCR in a recycling process for encapsulated beneficial use, or (b) dispose of the CCR in a permitted landfill on the property upon which the CCR unit is located, adjacent to such property, or off of such property in a facility that includes, at a minimum, a composite liner and leachate collection system that meets or exceeds the federal Criteria for Municipal Solid Waste Landfills pursuant to 40 C.F.R. Part 258;

(ii) beneficiate at least 6.8 million cubic yards of CCR from at least two of the Power Stations; and

(iii) develop a transportation plan in coordination with local governments impacted by the transport of CCR to offsite storage locations to include: (1) alternative transportation options to be utilized; (2) plans for any transportation by truck; and (3) public posting of the plan.

Q. Has the Company identified any of its Power Stations for which it will beneficiate the CCR?

A. Yes. As noted above, the Virginia CCR Statute requires beneficially reusing CCR or disposing of the CCR in a permitted landfill on the property upon which the CCR pond is located, adjacent to the property upon which the CCR unit is located, or off the property on which the CCR unit is located. The Company's plan must beneficially reuse no less than 6.8 million cubic yards of CCR in the aggregate from no fewer than two of the sites.

Given the physical limitations of the onsite landfill at Chesterfield Power Station, a significant amount of the CCR material will need to be transported from this station. Additionally, since the Chesapeake Energy Center facility does not have the physical space to construct an on-site landfill, this limits the options available to the Company for CCR removal at this location, to transportation from the site to either a permitted landfill or to a vendor providing beneficiation services.

Based on these factors, it was determined that beneficiating CCR material at both Chesterfield Power Station and Chesapeake Energy Center was the most cost-effective method to remove CCR from both sites, rather than transporting it to an off-site landfill, given the constraints and beneficiation requirements of the Virginia CCR Statute.

Q. Please provide the current key operational milestones including landfill construction dates, ash excavation start and completion dates, as well as final closure dates.

A. Table 1 below provides an update to the key operational milestones for the Company's four CCR projects, which include a project at each of the Power Stations.

<u>Table 1</u>

Milestone	Chesterfield	Bremo	Possum	CEC
Start Landfill Construction	Q2-2021	Q3-2025	Q4-2025	TBD
Start Ash Excavation/Hauling	Q4-2021	Q3-2028	TBD	TBD
Complete Landfill Construction (all phases)	Q4-2026	Q3-2028	Q3-2027	TBD
Complete Hauling Ash	Q2-2033	Q3-2033	TBD	TBD
Start Beneficiation	Q2-2024	N/A	N/A	TBD
Complete Beneficiation	Q1-2033	N/A	N/A	TBD
Complete Closure Construction (final restoration)	Q1-2034	Q1-2035	TBD	TBD
Complete Final Grading	Q1-2034	Q3-2036	TBD	TBD

Q. What is the amount of the costs that the Company requests for recovery in this case?

A. The Company is seeking recovery of approximately $620 million in this case. The Company anticipates ongoing annual costs to be steady for the remaining years of these projects.

Q. Please discuss further the CCR investments made by the Company since the 2019 Rate Case.

A. The following sections describe the work proposed and occurring at each Power Station, along with the estimated costs.

A. BREMO POWER STATION CCR REMOVAL

Q. Please provide the location and status of the CCR located at the Bremo Power Station.

A. The Company has consolidated site CCR material into the North Ash Pond onsite and stabilized the pond with a temporary rain cover. The rain cover prevents precipitation from contacting the CCR, which helps reduce water treatment costs.

Q. What closure actions has the Company taken at Bremo Power Station?

A. The Company is required by the Virginia CCR Statute to remove and either beneficiate or transfer to a qualified landfill the approximately 6 million cubic yards of CCR at the Bremo Power Station. To address this requirement, the Company purchased property adjacent to, and contiguous with, the Power Station, near the North Ash Pond, where all the current CCR is located. The

Company is developing a design to construct a new landfill on this property and plans to move the CCR to the new landfill. The location of the new landfill being permitted allows for transportation of all CCR material to the landfill on Company property and avoids transportation on public roads. The Company has moved forward with rezoning the property and has acquired a special use permit from Fluvanna County that allows for the construction and operation of the landfill. The Company has undertaken the necessary permitting efforts for the landfill and is actively working to complete the landfill permitting process in 2024.

In August 2022, the Company executed the contract for the construction of the water treatment system to treat contact water during the excavation of the North Ash Pond. Construction of the water treatment system commenced in October 2022. The contractor achieved construction Mechanical Completion on December 19, 2023, and is working towards Provisional Acceptance (PA) and the ability to start treating water early 2024.

The water treatment system will be used to treat the water in the West Pond, which is currently being used as a holding pond for deep well contact water from the North Ash Pond. The West Pond, previously known as the West Ash Pond, had all its CCR material excavated prior to approval of the Virginia CCR Statute. The water from the deep wells installed in the North Ash Pond (which is water that contacts CCR material) is currently being pumped to the West Pond to be stored until the new water treatment system is operational. Treatment of this water will take approximately six to twelve months.

Subsequently the system will be used to start treating the contact water collected during excavation of CCR material from the North Ash Pond.

The North Ash Pond is currently covered with a temporary rain covering; the storm water collected there does not contact CCR material, and therefore does not get pumped to the West Pond for future treatment. This storm water is released through the permit approved outfalls at the site.

Q. Please provide an update on the timeline for construction of the landfill at the Bremo site and when the Company expects to begin hauling CCR material to it.

A. Following approval of the outstanding permits, the initial landfill construction is scheduled to start in Q3 2025 as indicated in Table 1. Construction of the landfill is estimated to be complete by Q3 2028 and CCR excavation and hauling is scheduled to start in Q3 2028 after the landfill is constructed.

The forecasted completion date for CCR transfer is around Q3 2033. The Company would then close the North Ash Pond in 2035.

Q. What is the expected total cost of the Bremo Power Station CCR Project?

A. The estimated cost of the Bremo Power Station CCR Project is approximately $678.5 million on a system basis, which represents costs through 2036.

B. CHESTERFIELD POWER STATION CCR REMOVAL

Q. Please provide the location and status of the CCR located at the Chesterfield Power Station.

A. Chesterfield Power Station currently has CCR located in the Upper and Lower Ash Ponds. The Upper Ash Pond has not received CCR materials since February 2018. In 2023, approximately 384,340 cubic yards were excavated from the upper portion of the Upper Ash Pond and hauled to the existing onsite Fossil Fuel Combustion Products "FFCP" Management Facility ("Reymet Landfill"). The undisturbed side slopes of the Upper Ash Pond remain stabilized with vegetative cover while the upper portions of the pond that have been partially excavated have a welded geomembrane rain cover installed until excavation resumes for beneficiation and landfilling.

In 2023, approximately 393,858 cubic yards of ash were excavated from the eastern portion of the Lower Ash Pond and hauled to the Reymet Landfill. Contact water from the eastern portion of the Lower Ash Pond is being sent to the site's water treatment system. The western portion of the Lower Ash Pond remains covered with a temporary, welded geomembrane rain cover to allow for the continued management of non-contact stormwater under the station's Industrial General Stormwater Permit, allowing for a more cost-effective solution for water management.

In total, during 2023, a volume of 777,952 cubic yards of CCR was excavated at Chesterfield Power Station.

Q. What is the CCR removal plan for the Chesterfield Power Station?

A. The Company intends to beneficiate a portion of CCR material with the remaining material to be landfilled in the existing FFCP Management Facility, which is being constructed and utilized in multiple phases. Phase 3 excavation is currently underway. Ash produced after the wet-to-dry conversions at the station prior to cessation of operations was placed in Phase 1. To date, CCR excavated from the Upper and Lower Ash Ponds has been placed in Phases 1 and 2. The remainder of the ash to be landfilled will be placed in FFCP Management Facility including in Phases 3 and 4 that will be constructed to accommodate the CCR from these ponds. The Company began moving CCR from the ponds to the FFCP Management Facility and separately to a recycler for beneficiation during Q4 2021. Construction of a beneficiation structure to load CCR into rail cars for offsite transport was completed in February 2022. In 2022, 483,968 cubic yards of ash were moved from the Upper Ash Pond to the Reymet Landfill. In parallel, 50,852 cubic yards of coal ash were beneficiated in 2022, and an additional 246 cubic yards were beneficiated in 2023 as part of the 2023 beneficiation RFP. CCR removal from the Upper and Lower Ash Ponds is expected to be completed in Q2 2033, and the Company will then close the CCR ponds in approximately Q1 2034.

Q. Please provide an update on beneficiation at Chesterfield Power Station.

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

Q. What actions has the Company taken to address this issue?

A. A new Request for Proposals ("RFP") for beneficiation services was issued on December 15, 2022 for both the Chesterfield Power Station and the Chesapeake Energy Center. Through the RFP it was determined that the most cost-effective approach to meeting the Virginia CCR Statute requirements was to beneficiate 6.8 million cubic yards of ash from the Chesterfield Power Station. As a result of the extensive RFP process, as of March 1, 2024, Holcim is contracted for the Chesterfield beneficiation. Holcim is the leading manufacturer of cement in the United States. To meet the requirements of the Virginia CCR Statute, a portion of the bottom ash material from the Chesapeake Energy Center will also be beneficially reused at a later date.

Q. What is the expected total cost of the Chesterfield Power Station CCR Project?

A. The estimated cost of the Chesterfield Power Station CCR Project is approximately $2.32 billion on a system basis, which represents costs through 2037.

C. POSSUM POINT POWER STATION CCR REMOVAL

Q. Please provide location and status of the CCR located at the Possum Point Power Station.

A. Possum Point Power Station CCR material has been consolidated into Pond D.

Q. What is the CCR removal plan for the Possum Point Power Station?

A. The Company intends to remove the CCR from Pond D and store it in an on-site landfill. This represents the most cost-effective approach for remediation of CCR at the site.

Q. Please discuss the Company's progress with this removal plan.

A. The Company obtained a Local Government Certification ("LGC") in October 2022 indicating that the on-site landfill option met Prince William County's zoning requirements. Currently, the Company is progressing the Solid Waste Permit Part A application through the VDEQ process and preparing the Part B application for submittal. Once the Part B application is approved and the solid waste permit is issued, the Company will start construction of the on-site landfill.

In January 2023, the Company executed the contract for the construction of the water treatment system to treat contact water stored in Pond D and during the excavation of the North Ash Pond. Construction of the water treatment system is scheduled to commence in March 2024 with initial operations scheduled for Q2 2025.

Q. What is the expected cost of the Possum Point Power Station CCR Project?

A. The estimated cost for the Possum Point Power Station CCR Project is $500.9 million on a system basis, which represents costs for CCR removal and transfer to an on-site landfill.

D. CHESAPEAKE ENERGY CENTER CCR REMOVAL

Q. Please provide the location, and status of the CCR located at the Chesapeake Energy Center.

A. Chesapeake Energy Center CCR material remains onsite in an area south of the former power block.

Q. What is the CCR remediation plan for the Chesapeake Energy Center?

A. The Company intends to beneficiate or recycle most of the remaining bottom ash CCR located at this site, and plans are being developed for the removal of the CCR and for final closure of the landfill and pond areas. The Company has undertaken engineering work to support the relocation of the transmission towers and the groundwater modeling for the purpose of dewatering. The City of Chesapeake approved a Conditional Use Permit for the project on December 21, 2022.

Q. What is the expected cost of the Chesapeake Energy Center CCR Project?

A. The estimated cost for the Chesapeake Energy Center CCR Project is $623.5 million on a system basis, which represents costs incurred through 2041.

Q. In your opinion, and based upon your experience, has the Company made reasonable and prudent investments in its generation fleets to ensure adequate and reliable electric service to DENC's customers in North Carolina?

A. Yes. In my opinion, these investments have been prudently incurred and are intended to ensure adequate and reliable electric service to DENC's retail customers in North Carolina.

Q. Does this conclude your direct testimony?

A. Yes.

BACKGROUND AND QUALIFICATIONS OF JEFFREY G. MISCIKOWSKI

Jeffrey Miscikowski is Vice President – Project Construction. He is responsible for working across all business units to construct major generation, environmental, and gas projects – supporting the company's clean energy transition.

Mr. Miscikowski joined Dominion Energy in 2001 as a Trading Analyst and was named Manager–Analytic Trading Support in 2002. He was promoted to Director–Fuel Operations in 2005. In 2007, he joined the Generation Construction group as Director–Construction Project Controls responsible for coordinating budgeting, scheduling, and contracting efforts for large generation and environmental projects. In 2020, he was promoted to General Manager–Construction Projects (Controls) for the expanded Project Construction organization. He assumed his current position in June 2023 as Vice President – Project Construction.

Prior to joining Dominion Energy, Mr. Miscikowski was a Senior Process Engineer for Lucent Technologies and then Viasystems Technologies in the printed circuit board industry. Before this role, he served as a defense industry analyst at M.I.T Lincoln Laboratory.

Mr. Miscikowski received a bachelor's degree in electrical engineering and mathematics from the University of Wisconsin-Madison, and a master's degree in business administration from the College of William & Mary.

DIRECT TESTIMONY
OF
KEVIN L. FIELDS
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 694

Q. Please state your name, position of employment, and business address.

A. My name is Kevin L. Fields. I am employed by Dominion Energy Technical Solutions, Inc. as Director, Electric Transmission Project Management Organization. My business address is 5000 Dominion Boulevard, Glen Allen, Virginia, 23060.

Q. Please describe your area of responsibility within the Company.

A. I am responsible for executing the Electric Transmission project portfolio. A statement of my background and qualifications is attached as Appendix A.

Q. Have you previously testified before this Commission?

A. No.

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

A. My testimony supports Dominion Energy North Carolina's ("DENC" or the "Company") overall request to adjust North Carolina base rates to recover the cost of providing reliable electric service to its customers in North Carolina. Specifically, I explain the Company's major investments in its transmission and North Carolina distribution ("T&D") electric system since its last general rate case in 2019 and describe the benefits to DENC's customers resulting from those investments.

Q. Please generally describe DENC's T&D electric system in North Carolina.

A. DENC's distribution system delivers electric service to over 127,000 customers in northeastern North Carolina across a service territory of approximately 2,600 square miles, including Roanoke Rapids, Ahoskie, Williamston, Elizabeth City, and the Outer Banks. The Company's retail service territory is located within the Company's transmission system, which also includes North Carolina Electric Membership Corporation ("NCEMC") and North Carolina Eastern Municipal Power Agency ("NCEMPA") customers.

The Company's T&D electric system in North Carolina includes approximately 1,000 miles of transmission lines, providing electricity to approximately 30 delivery points, including directly to North Carolina industrial customers taking service at transmission voltage. DENC also operates seven transmission voltage interties with Duke Energy Progress at the southern border of DENC's system. The Company also operates more than 4,000 miles of overhead distribution lines and 900 miles of underground distribution lines. In addition to power lines and substations, the Company's T&D system includes various other equipment and facilities such as control houses, communications facilities, transformers, capacitors, streetlights, meters, and protective relays. Together, these assets provide the Company's

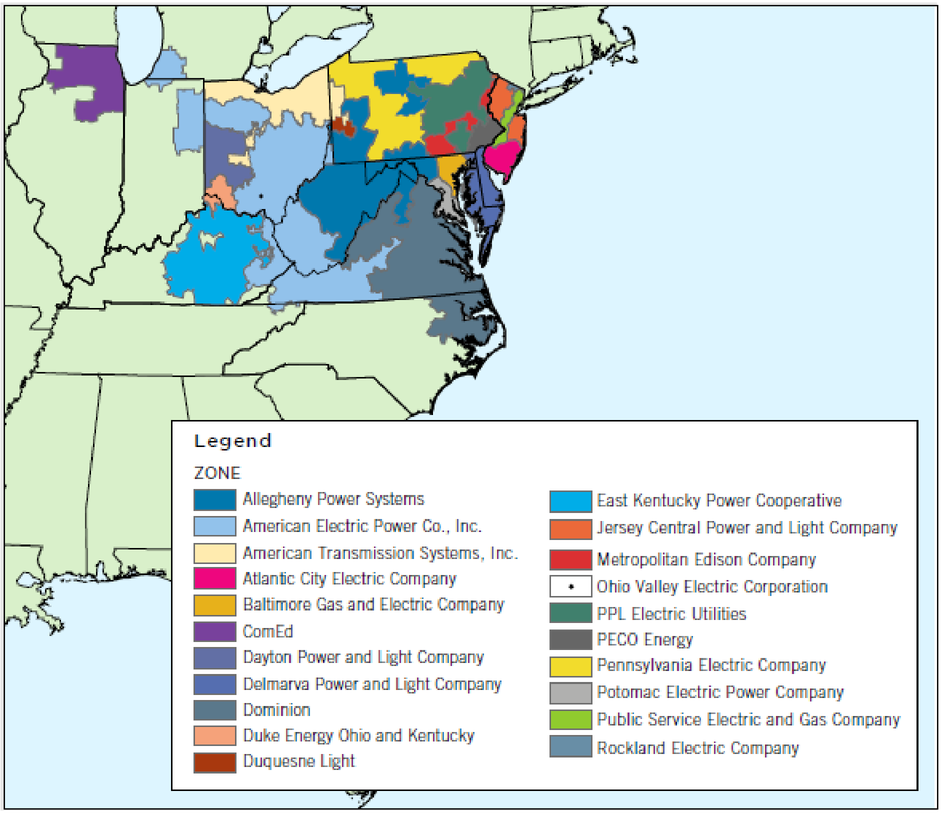
T&D system with considerable operational capability and flexibility and allow DENC to provide safe, reliable, and economical power to the Company's customers in North Carolina.

Q. Please provide an overview of the Company's electric transmission system.

A. The Company's transmission system transports power from generating resources to distribution systems to serve the demand of the end-user customers. Reliable transmission system operation implies maintaining continuity of service at sufficient voltage levels without overloading equipment under a wide range of operating conditions. "Transmission system" refers to networked and radial facilities within the Company's system at voltage levels 69 kV or greater. The Company continually works to ensure adherence to the transmission planning standards of the North American Electric Reliability Corporation ("NERC") and those of the SERC Reliability Corporation ("SERC").

The Company is part of PJM Interconnection, L.L.C. ("PJM"), the regional transmission organization that provides service to a large portion of the eastern United States and is the designated "Transmission Operator" for the Dominion transmission zone (the "DOM Zone"). Figure 1 below presents a map of the DOM Zone within the PJM footprint. PJM currently is responsible for ensuring the reliability of, and coordinating the movement of, electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

FIGURE 1



Based on PJM's most recent load forecast, release in January 2024, the DOM Zone is expected to be the fastest growing zone in PJM over the next decade, with average peak demand growth rates of 5.6% (summer) and 5.1% (winter). This growth rate is significant when compared to other PJM participant zones that are projected to grow at an average rate of 1.7% (summer) and 2.0% (winter) over the same period.

The Company actively studies its transmission zone and its ties with neighboring utilities to ensure reliable delivery of electricity can be maintained at all times and in all contingency situations. PJM provides additional support in both these zonal studies as well as its review of overall system conditions, including generator deliverability studies targeted to evaluate network abilities and ensure generation capacity resources can deliver energy to load areas. The Company is also part of the Eastern Interconnection transmission grid, meaning its transmission system is interconnected, directly or indirectly, with all of the other transmission systems in the United States and Canada between the Rocky Mountains and the Atlantic Coast, except for Quebec and most of Texas. All of the transmission systems in the Eastern Interconnection work together to ensure their ability to move bulk power through the transmission system and for reliability support.

Q. Please explain why investment in electric transmission is key to providing safe, reliable, and economical power to the Company's North Carolina customers.

A. At the highest level, the Company invests in its electric transmission system to ensure reliability and ongoing compliance with NERC reliability standards and requirements, address load growth, and repair or replace aging infrastructure. These investments ensure the Company's continued ability to provide safe, reliable, and economical power to its customers.

Q. Please highlight some of the major transmission investments that DENC has completed in North Carolina since 2019.

A. In North Carolina specifically, DENC completed approximately $316 million of electric transmission projects from 2019-2023 to support end of life reliability and economic development, including rebuilding and refurbishment of approximately 57 miles of existing 230 kV lines and 65 miles of existing 115 kv lines.

Q. Do the Company's electric transmission system investments completed in Virginia benefit North Carolina customers?

A. Yes. Due to the interconnected nature of the electric transmission system, investments completed on the Company's system, including in Virginia, provide customers in North Carolina with access to affordable and reliable electricity supply to the Company's jurisdictional retail customers and wholesale cooperatives.

Q. Is the Company planning additional transmission system improvements over the next few years?

A. Yes. The Company is planning to invest approximately $7 billion in new transmission system improvements over the next three years. Of that amount, over $250 million is planned specifically for strengthening its North Carolina transmission system. Another portion of that amount will support investments throughout the Company's service territory. This includes projects related to reliability and load growth, a large portion of which is data center growth. In addition to generally strengthening the system, as discussed by Company

Witness Robert E. Miller, this load growth has contributed to the decrease in the North Carolina jurisdictional allocation factor, thus benefiting North Carolina customers.

Q. Please discuss the importance of the Company's investments in its distribution system in North Carolina.

A. The Company maintains a strong focus on maintaining and improving its distribution facilities in its North Carolina service area. Although DENC's retail loads have remained relatively stable over this period, as highlighted by Company Witness Miller, winter peak demands in some areas of our North Carolina service area, including the Outer Banks and parts of Currituck and Camden Counties, have increased by 20% over the last 10 years. The investments in the distribution system that we have made since 2019 will help the Company ensure reliable service to its North Carolina customers during peak demand events.

Q. Please discuss further the reliability of the Company's distribution retail service in North Carolina.

A. The Company's investments to expand and strengthen its transmission and distribution infrastructure in northeastern North Carolina are intended to support the Company's provision of dependable and reliable electric service for its customers. System Average Interruption Duration Index ("SAIDI") is an industry accepted measure of reliability performance for retail service. The Company's distribution operations maintained an average annual SAIDI of 120 minutes over the last five years excluding major storms. The Company's northeastern North Carolina service territory remains exposed to severe weather events as evidenced by seventeen days over the course of the past five-years when the North Carolina territory experienced weather-related outage activity exceeding the Major Event Day ("MED") threshold. The Company determines MED thresholds using the industry standard IEEE 1366 methodology. This standard is a statistical approach to determining days on which the energy delivery system experiences stresses beyond that normally expected (such as during severe weather).

To improve daily distribution system performance and to proactively prepare for severe weather events, DENC continues to strengthen its transmission and distribution infrastructure in northeastern North Carolina.

Q. Please describe the Company's recent and ongoing investments to strengthen and expand its distribution system in North Carolina.

A. DENC has made a number of investments, totaling approximately $47 million , to improve its North Carolina distribution system since the 2019 Rate Case. Notable electric distribution projects include the reconductoring and reconditioning of 22 miles of overhead lines throughout our service territory to support increased reliability, the addition of 33 MVA of capacity at Northampton Substation to support commercial load growth, the retirement of the Columbia substation and the installation of modernized facilities to support load growth and increased reliability, and the hardening of 1.3 miles of facilities crossing the Roanoke Island Causeway to support increased resiliency and reliability.

Q. Is the Company planning additional distribution investments over the next several years?

A. Yes. The Company is planning approximately $35 million of distribution investment over the next three years to support load growth and reliable service in our North Carolina service territory. Notable projects include: the installation 2.25 miles of underground facilities to increase our load serving capacity to over 1,800 customers on Colington Island, the reconditioning of 2.3 miles of overhead facilities along NC Hwy 12 to further mitigate salt contamination concerns in the Outer Banks, and the reconductoring of nearly 30 miles of overhead mileage in various parts of our North Carolina service territory to increase capacity.

Q. Is the Company including costs related to other transmission and distribution investments in this proceeding?

A. Yes. Costs related to the deployment of Advanced Metering Infrastructure ("AMI") in North Carolina are also included in this proceeding.

Q. Please provide an overview of AMI.

A. The term AMI refers to "smart meters" and their associated infrastructure. Smart meters are electric meters that digitally gather energy usage data in specified increments throughout the day (*i.e.*, interval data) and other related information. With AMI, the Company can remotely read data gathered by smart meters and send commands, inquiries, and upgrades to individual smart meters. This functionality enables a host of benefits, including but not limited to, advanced time-varying rates, targeted demand-side management programs, reduced components of the cost of service, enhanced grid operations, and enhanced DER integration.

Q. How does AMI benefit North Carolina customers?

A. The Company's investment in AMI helps to modernize the distribution grid and brings the many benefits of AMI to customers as the Company replaces aging automatic meter reading ("AMR") meters. AMR meters have considerable functional limitations compared to smart meters and have limited vendor support due to their obsolescence. AMI is foundational to a modern distribution grid based on the real-time data it provides—including interval energy usage data and customer voltages, among other characteristics of electrical service at that endpoint—and is crucial to ensuring the integrity, reliability, and resilience of the electric distribution system. AMI enables advanced time-varying rates, enhances demand-side management programs, and enhances grid operations by functioning as end-of-line sensors. These sensors generate premise-level data that is increasingly important given the expansion of distributed energy resources behind customer meters (such as electric vehicles and self-generation facilities).

AMI also results in O&M savings, for example, by reducing metering labor and vehicles, reducing bad debt expense, and reducing energy diversion, all of which can reduce components of the cost of service for customers. For the community, AMI reduces greenhouse gases by reducing vehicle usage. Beyond these benefits, AMI improves the customer experience, reduces hazard exposure for employees, enhances load forecasting, and enhances cost-of-service studies.

Q. What is the status of the Company's rollout of AMI in North Carolina?

A. The Company is working to install approximately 127,000 smart meters in North Carolina. As of the end of February 2024, the Company's AMI deployment is a little more than 50% complete in our North Carolina service territory. Deployment in North Carolina will be largely completed by September 2024.

Q. Does the Company allow residential customers to "opt-out" of AMI metering at their residences?

A. Yes. A small minority of customers have expressed concerns about the AMI technology being used at their residences. The Company has allowed those customers who are eligible to opt-out of AMI.

Q. What is the consequence of a customer opting-out of AMI?

A. When a customer opts out of smart meter installation or requests to replace their existing smart meter with a non-communicating meter, the Company must expend additional resources both initially and on an ongoing basis. Up front, there are administrative expenses associated with a customer's initial decision to opt out of smart meter installation, such as program administration and reporting, customer communications and account management, work order generation and scheduling, and inventory management and shipping. The Company must also exchange the customer's existing meter for an opt-out meter and send someone to read the non-communicating meter manually on a monthly basis.

Q. What is the Company's current opt-out practice for smart meters in North Carolina?

A. Currently, qualifying residential customers (defined as residential customers on Rate Schedule 1 who have accounts in good standing and who do not participate in net metering) are allowed to opt out of smart meter installation upon request and at no expense. These customers receive an information packet explaining the benefits of AMI that they would forego by opting out. The customer is required to complete and return forms confirming their acknowledgement that opting out at no expense is an interim solution until the Company has an opt-out policy approved by the Commission.

Q. Please describe the AMI opt-out policy the Company is proposing in this proceeding.

A. Under the Company's proposed opt-out policy, qualifying residential customers (as defined in the Company's Terms and Conditions Section X) will be eligible to opt out of smart meter installation upon request. The Company will not charge a one-time initial fee for the installation of the non-communicating meter but will impose an ongoing monthly fee intended to recover the labor and administrative costs associated with the monthly meter reading. Additionally, the Company proposes to assess the same monthly fee to customers that have both refused installation of a smart meter and failed to comply with the smart meter opt-out process. The charges are explained in the testimony of Company Witness Miller.

Q. In your opinion, and based upon your experience, has the Company made reasonable and prudent investments in its T&D system to ensure adequate and reliable electric service to DENC's customers in North Carolina?

A. Yes. The Company has invested strategically to expand and strengthen its transmission and distribution infrastructure in northeastern North Carolina, and throughout its system, as part of DENC's core mission to ensure reliability, operational excellence, and efficient service for its customers. In my opinion, these investments have been prudently incurred and are intended to ensure adequate and reliable electric service to DENC's retail customers in North Carolina.

Q. Does this conclude your direct testimony?

A. Yes.

BACKGROUND AND QUALIFICATIONS
OF
KEVIN L. FIELDS

Mr. Fields received his bachelor's degree in electrical engineering in 2001, and his masters degree in electrical engineering in 2004 from Virginia Commonwealth University. He is a registered professional engineer in the state of Virginia and is certified through PMI as a project management professional. Mr. Fields joined Dominion Energy after serving 8 years in the U.S. Army. He has worked in various roles from distribution construction and generation/transmission projects, as well as ET Transmission services which includes real estate, permitting, finance, and contracts.

Mr. Fields is currently the Director of the Transmission Project Management Organization where he is responsible for executing the transmission project portfolio through project management oversight, transmission services as defined above, and project portfolio budgetary management.

DIRECT TESTIMONY
OF
ROBERT E. MILLER
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 694

Q. Please state your name, business address, and position of employment.

A. My name is Robert E. Miller, and my business address is 120 Tredegar Street, Richmond, Virginia 23219. I am a Manager - Regulation for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company").

Q. Please describe your areas of responsibility within the Company.

A. I am responsible for preparation of the cost of service studies, distribution plant-related allocation factors, and minimum system analysis. A statement of my background and qualifications is attached as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes. I provided direct, supplemental, and rebuttal testimony to the Commission in the Company's previous rate case in Docket No. E-22, Sub 562 ("2019 Rate Case"). In addition, I have provided direct testimony in Docket No. E-22, Sub 577 and in Docket No. E-22, Sub 589.

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

A. I am sponsoring the cost of service studies filed in Item 45 (a – f) of the Form E-1, Rate Case Information Report – Electric Companies. My testimony addresses the Company's proposed allocation methodology for production and transmission plant, as well as some alternative allocation methodologies. In addition, I address the allocation of distribution plant and related expenses. Furthermore, my testimony describes the cost of service studies used to produce Item 45. I also address a question raised by the Commission in Docket No. E-100, Sub 101 regarding the impact of distributed generation on the allocation of distribution plant cost responsibility. Finally, my testimony addresses certain updates to the Company's Terms and Conditions.

Q. Mr. Miller, how is your testimony organized?

A. I have divided my testimony into the following sections:

I. OVERVIEW OF COST OF SERVICE STUDIES

II. COST ALLOCATION – SUMMER WINTER PEAK AND AVERAGE METHODOLOGY

III. COST ALLOCATION - OTHER COST ALLOCATION METHODOLOGIES

IV. COST ALLOCATION – ALLOCATION OF DISTRIBUTION PLANT COSTS

V. SUMMARY OF COST OF SERVICE SCHEDULES AND FORM E-1, ITEM 45

VI. ADDITIONAL COST ALLOCATION AND COST OF SERVICE TOPICS

VII. TERMS AND CONDITIONS

Q. As part of your testimony, will you be introducing any exhibits?

A. Yes. I am sponsoring Company Exhibit REM-1, which consists of Schedules 1 through 29. This exhibit was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief. Schedules 5 through 10 provide and summarize information filed in Item 45 of Form E-1.

I. OVERVIEW OF COST OF SERVICE STUDIES

Q. Please explain the purpose of cost allocation within the context of the cost of service study.

A. The Company keeps records on a system basis, and in some cases on a jurisdictional basis, as required by various regulatory authorities. For the most part, these system records do not indicate the amount of each system cost that was incurred to provide service to a jurisdiction or customer class. The objective of jurisdictional and class cost of service studies is to determine the share of the system's revenues, expenses, and plant related to providing service in a particular jurisdiction or class – which in this case is service to the Company's customers in North Carolina under the jurisdiction of the North Carolina Utilities Commission ("Commission").

Q. How are jurisdictional cost amounts determined?

A. The jurisdictional cost amounts are determined in several ways. First, certain items can be determined by direct assignment. For example, the largest portion of operating revenue is from the sale of electricity. Revenues can be determined from the Company's billing records and directly assigned to the respective jurisdictions and customer classes. Second, in order to determine for a particular jurisdiction or class its share of the revenues, expenses, or plant not directly assignable, the overall amount is allocated in proportion to some reasonably related item or measurable characteristic. For example, fuel is consumed in power plants to provide electric service to all jurisdictions and classes, so it is not reasonable to assign the fuel and fuel-related expenses of a particular power station on the basis of the facility's location. However, fuel and fuel-related expenses are related to the number of kilowatt-hours ("kWh") of electricity produced, and the Company maintains records showing how many kWh were purchased by customers in each jurisdiction. Therefore, a formula, or "allocation factor," is derived from a ratio between jurisdictional and system kWh sales, and that allocation factor is used to apportion fuel and fuel-related expenses among the jurisdictions and, subsequently, to the customer classes.

Q. What steps are necessary to determine the appropriate allocation factor to use for each item in the cost of service study?

A. As indicated by the example above regarding fuel and fuel-related expenses, in order to determine the best allocation factor to use, one must have information about the nature of the costs involved. To that effect, the preparation of a jurisdictional cost of service study requires that each cost item in the system be separated into its appropriate demand, energy, and customer-related components (a process known as the "classification" of costs).

Demand-related costs consist of the major fixed investments for power production, transmission, a portion of distribution, and the expenses related to these investments. These are costs that result from the Company's obligation to serve customers and vary in proportion to the kilowatts ("kW") of demand imposed by customers on the Company's system. Energy-related costs vary in proportion to kWh consumption and consist principally of fuel-related expenses. Customer-related costs vary in proportion to the number of customers served, such as metering costs, customer accounting costs, and a part of the cost of the distribution facilities.

Along with the "classification" step, another intermediate step called "functionalization" is used in the allocation process. Generally, costs can be attributed to the major function to which they relate, such as production, transmission, and distribution. For the most part, this is a fairly simple process because the Company's cost of service studies follow the primary Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts detail, and the line items of the studies show the applicable FERC Account number.

Q. Please continue with your discussion of how the cost of service studies were prepared.

A. Once the classification and functionalization steps are completed, an appropriate demand-, energy-, or customer-related jurisdictional allocation factor is applied to the related component to determine the allocation amount for that cost item to the jurisdiction. In most cases, expenses or costs are allocated on related plant, although some expenses, such as fuel, are allocated separately on more appropriate allocation factors.

System costs and external allocation factors are the principal starting points of the allocation process. External allocation factors are based on data obtained from Company records – for example, kWh consumed in each jurisdiction. Functionalized costs are allocated by external allocation factors, such as the Production Demand Factors (Factor 1 or 61), Transmission Demand Factor (Factor 2), Distribution Demand Factors (Factors 8 through 16), Customer Factors (Factors 17-22), etc., for the respective functions. Each allocation factor is as closely related as practicable to the item to be allocated.

Many other allocation factors are derived during the course of producing the cost of service studies and are based on various combinations of data already allocated. These factors are called internal allocation factors because they are generated from calculations within the cost of service studies.

Q. Should costs be fully allocated among jurisdictions and customer classes?

A. Yes. The cost of service studies should fully allocate system costs to jurisdictions in the jurisdictional cost of service. Costs that have been allocated to a jurisdiction should be fully allocated to customer classes in that jurisdiction. Costs that are not fully allocated in either the jurisdictional study or subsequent customer class study would effectively not be recovered through rates approved by the various regulatory commissions or authorized by contracts for those customer groups not subject to the jurisdiction of a regulatory commission.

II. COST ALLOCATION – SUMMER WINTER PEAK AND AVERAGE METHODOLOGY

Q. What allocation method has the Company used in this proceeding to allocate production and transmission plant?

A. In its cost of service studies, the Company has allocated production and transmission plant, and their related expenses, using the Summer/Winter Peak and Average ("SWPA") method.

Q. Is the SWPA methodology consistent with the methods used to allocate production and transmission fixed costs in the Company's jurisdictional cost of service and customer class cost of service studies presented in prior proceedings?

A. The Company has proposed and the Commission has authorized the SWPA methodology for the allocation of production and transmission plant in DENC's last seven general rate cases, Docket Nos. E-22, Sub 273 (1983), Sub 314 (1990), Sub 333 (1992; the "1992 Rate Case"), Sub 459 (2010), Sub 479 (2012), Sub 532 (2016; the "2016 Rate Case"), and Sub 562 (2019; the "2019 Rate Case"), and in the Commission's 2004 general rate investigation, Docket No. E-22, Sub 412. Most recently, the Commission stated, in final order in the 2019 Rate Case, that:

> the SWPA cost of service methodology provides the most appropriate methodology to assign fixed production costs by incorporating DENC's seasonal peak demands at the two single

> hours they occur and by incorporating the total energy consumed by the jurisdiction and customer classes over all the other hours of the year. In addition, the Commission finds good cause to require that the Company should continue to file a cost of service study using the SWPA methodology annually with the Commission.[1]

Q. Please explain the SWPA allocation methodology.

A. The SWPA method recognizes two components of providing service to customers, peak demand, and average demand, when determining the responsibility for costs of production and transmission plant and related expenses. The peak demand component takes into account the hour when the load on the system is highest during both the summer months (June through September) and the winter months (October through May).

The average demand component recognizes that there is a load incurred by the system over the course of all hours during the year. The average demand is determined based upon the total energy provided to the customers during the year divided by the total number of hours in the year.

The SWPA method recognizes that these two components (peak demand and average demand) should be weighted before determining the resulting allocation factor. The weight for each component is based upon the relationship of the two components. The ratio created by dividing the average demand by the peak demand is the system load factor and is used to weight

[1] *Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase* at 72-73, Docket No. E-22, Sub 562 (Feb. 24, 2020) (the "2019 Rate Order").

the average demand component. Subtracting this ratio from one obtains the ratio used to weight the peak demand component.

Q. Why is the Company supporting the use of the SWPA method in this proceeding?

A. The Company is supporting use of the SWPA method for several reasons. First, the SWPA allocation method recognizes that cost responsibility for system costs associated with production and transmission plant and related expenses should be "balanced" based upon having sufficient capacity to meet peak demand, while also having capacity that can be operated efficiently and cost effectively over all other hours of the year. The "Summer and Winter" peak component recognizes the total level of generation resources necessary to serve the system peak, while the average component recognizes the type of generation serving customers' energy needs year-round.

Without an "average" component in the allocation factor, all production plant would be allocated based on the jurisdictional and customer class contribution to demands at the peak hour. Reliance on a "peak-only" approach necessarily assumes that the Company's total production plant investment was made only to serve the peak load that occurs during one hour on a single day during the year. While serving peak load is clearly one driver of the Company's generation resource planning, another important component is the need to serve customers' electricity needs throughout the year. By considering both the peak demand component and the average demand, or energy consumption, component, the SWPA methodology better reflects the Company's need to serve customers not only at the peak hour but at every hour throughout the year.

Another reason for including an average component is that a single peak methodology allows certain customer classes that have zero demand during the peak hour of the year to fully avoid responsibility for production plant costs. One common example is that streetlights normally do not operate during peak hours. Under a strict coincident peak allocation this class would not pay any fixed costs associated with production resources that are obviously used to power the streetlights throughout the year.

Another important example specific to the unique characteristics of DENC's North Carolina Jurisdictional load is the NS Class. This class consists of only one high load factor customer, Nucor Steel-Hertford ("Nucor"), which has an average annual demand (total annual kWh/ number of hours in the year) of approximately 84.7 MW. The average of Nucor's summer (July 28, 2023) and winter (February 4, 2023) coincident peak demands is approximately 34.4 MW. Without recognizing an average component in the cost allocation, this customer class would be allocated cost responsibility for only 34.4 MW and would escape cost responsibility for an average of 50.3 MW for the rest of the year (*i.e.,* the average demand of 84.7 MW less allocated demand of 34.4 MW). In sum, use of a peak-only methodology would allow the NS Class to avoid cost responsibility for 50.3 MW of power – equal to approximately 440,600 megawatt-hours – provided by the Company and actually consumed by Nucor throughout the year.

By recognizing both the energy needed to serve load at the peak hour as well as energy consumed throughout the year, the SWPA method allocates some portion of these system costs to all customers, including those customers that can reduce their peak demand and those that may not place a demand on the system during the respective summer and winter peak hour. Such customers still use and receive the benefit of the investments in production assets by paying lower energy costs, specifically fuel costs, during all other hours.

In this case, DENC contends – based upon its recent experience and consistent with its past seven rate cases – that SWPA provides the appropriate jurisdictional allocation of the Company's overall cost of service that reasonably and fairly reflects the cost of service rendered on behalf of DENC's North Carolina customers.

Q. Has the Company made any adjustments to the calculation of the SWPA allocation factors?

A. Yes. As with the calculations of the SWPA factors in the 2016 and 2019 Rate Cases, the Company has made an adjustment to summer and winter peak demands to recognize generation from certain non-utility generators ("NUGS"). In these prior cases, the Company adjusted the Company's "recorded" summer and winter peaks to recognize that the kW generated by certain NUGs are not included in those values. Effectively, this is the output of these units that reduces load that is measured on the Company's transmission system. This adjustment affects the Production Allocation Factors (1 and 61) and the Transmission Allocation Factor (Factor 2). The

Commission has, in both prior proceedings, concluded that this adjustment "appropriately recognizes the impact non-utility generators have on DNCP's utility system." [2]

Q. How is the SWPA methodology applied in the jurisdictional cost of service and customer class cost of service?

A. In the jurisdictional cost of service, the Company considers the average demand and the system coincident summer and winter peak demands for the North Carolina jurisdiction and the three other jurisdictions that compose the Company's system, the Virginia jurisdiction, the Virginia non-jurisdiction, and the Federal Energy Regulatory Commission ("FERC)" jurisdictional customers. First, the average demands based on annual energy for each jurisdiction and, correspondingly, for the system, are determined.

The ratio of each jurisdiction's average demand to the system average demand is then weighted by the system load factor to determine the appropriate weight of the average demand component of the allocation factor. The peak demand component is determined as the average of the summer peak and the winter peak. The ratio of each jurisdiction's average peak demand to the system peak demand is then weighted by (1 – system load factor). The weighted average demand component plus the peak demand component are added to obtain the allocation factor for each jurisdiction.

[2] 2016 Rate Order, Page 16, Finding of Fact No. 16.

For purposes of developing the North Carolina customer class cost of service, the Company once again considers the average demand and the system coincident summer and winter peak demands. First, the average demands based on annual energy for the North Carolina customer classes and, correspondingly, the North Carolina jurisdiction, are determined. The ratio of each class's average demand to the jurisdiction's average demand is then weighted by the system load factor from the jurisdictional cost of service to determine the appropriate weight of the average demand component of the allocation factor. The peak demand component is determined in the same manner as for the jurisdictions using the summer peak and the winter peak. The result is then summed to determine the final peak demand for each customer class. The ratio of each class's peak demand to the jurisdiction's peak demand is then weighted by (1 – system load factor). The weighted average demand component plus the weighted peak demand component are added to obtain the allocation factor for each customer class.

Q. Which SWPA factors were used to allocate production and transmission costs in this case?

A. In its cost of service studies, the Company has allocated production plant and fixed production-related expenses on the SWPA production demand allocation factors (Factors 1 and 61). With the exception of "Generation Interconnection Facilities" and "Power Supply Step-up Transformers," which are booked in the transmission-related FERC Accounts, the Company has allocated transmission plant and related expenses using the power supply SWPA demand allocation factor (Factor 2, which includes all loads on the transmission system). The "Generation Interconnection Facilities" and "Power Supply Step-up Transformers" are allocated on the SWPA production demand allocation factors (Factors 1 and 61). The allocation of these two costs as production-related is consistent with FERC's removal of these costs in the development of transmission tariffs under its jurisdiction.

Q. Can you provide the SWPA Factor 1 (production demand) and SWPA Factor 2 (transmission demand) for the Company's four jurisdictions and the North Carolina customer classes?

A. Yes. This information is provided in my Schedule 1, pages 1-4.

III. COST ALLOCATION – OTHER ALLOCATION METHODOLOGIES

Q. Did the Company agree to present the results of any other allocation methodologies in this proceeding?

A. Yes. As part of the Company's stipulation in the 2019 Rate Case, the Company agreed to conduct, for the North Carolina jurisdiction class cost of service only, an additional cost of service study using a Summer Winter Coincident Peak ("SWCP") allocation methodology. This methodology was only used to allocate costs at the North Carolina jurisdiction class level; the SWPA methodology described above was still used to allocate costs to the North Carolina Jurisdiction.

Q. How were the allocation factors using the SWCP method calculated?

A. While the SWPA method recognizes two components of providing service to customers, peak demand and average demand, the SWCP method only recognizes the peak demand components. As with the SWPA method, the SWCP uses the hour when the load on the system is highest during both the summer months (June through September) and the winter months (October through May). Because of this similarity, the calculation of the SWCP allocation factor functions in the same way as the SWPA calculation, except that the peak demand component is weighted at 100% (leaving the average demand component weighted at 0%). The calculation of the SWCP version of North Carolina class Factors 1 and 2 is shown in my Schedule 2, pages 1-2.

Q. Has the Company presented any other allocation methodologies in this proceeding?

A. Yes. In addition to the SWPA and the SWCP methodologies, per discussions with the Public Staff, the Company has also presented, for the North Carolina Jurisdiction class level, two studies using the Average and Excess ("A&E") methodology, one using the Company's standard approach and one using a modified approach.

Q. Please explain the A&E allocation methodology.

A. The A&E method takes into consideration the generation and transmission resources needed to serve the Company's "average load," as well as its "peak load," in allocating the costs of these resources to the various jurisdictions and customer classes. Thus, it considers the load factor or average use of the resources by each jurisdiction, and those resources and facilities required to generate and transmit the maximum amount of power required by each jurisdiction. Under the A&E methodology, all customers are allocated some portion of the production and transmission plant investment and "fixed" expenses related to the generation and transmission of power. From a generation perspective, this methodology is appropriate because it recognizes that the higher costs of baseload plants are incurred to achieve fuel cost savings. A simplified example of the calculation of an A&E factor is provided in Figure 1 below.

Figure 1:
SAMPLE CALCULATION OF AVERAGE AND EXCESS ALLOCATION FACTOR

		Total System	**Class A**	**Class B**
(1)	Loads at time of the System Peak	19,800,000	16,100,000	3,700,000
(2)	Jurisdictional Class Peak	20,300,000	16,400,000	3,900,000
(3)	kWh (000)	97,000,000	78,000,000	19,000,000
(4)	Average Load	11,073,059	8,904,109	2,168,950
(5)	System Peak less Average Load (Line 1 – Line 4)	8,726,941	7,195,891	1,531,050
(6)	Jurisdictional Class Peak less Average Load (Line 2 – Line 4)	9,226,941	7,495,891	1,731,050
(7)	Ratio (Line 5 / Line 6)	0.945810859		
(8)	Allocation of Excess (Line 6 x Line 7)	8,726,941	7,089,695	1,637,246
(9)	Average Load plus Excess (Line 4 + Line 8)	19,800,000	15,993,804	3,806,196
(10)	**Allocation Factor**	100.00%	80.78%	19.22%

The A&E allocation demand factor is composed of two parts - average demand and excess demand - and the factor in turn is based on three distinct usage characteristics: (1) contribution to the system peak for both generation and transmission (Line 1 in Figure 1); (2) the highest demand that occurred for each jurisdiction or class during the year (Line 2); and (3) annual kWh usage (Line 3). The average demand for the test year is calculated by dividing the test year number of kWh by 8,760 (the number of hours in the test year) (Line 4). The excess demand portion of the demand factor is the difference between the system average demand and the system peak demand (Line 5).

The system excess is then apportioned among the jurisdictions based upon the difference between the average demand and the highest demand of each jurisdiction (Line 6). A ratio of the system peak less average to the class peak less average (Line 7) is applied to the class peak less average (Line 8) to determine the allocation of the system excess to the classes. The sum of the class average demand (Line 4) and the class excess demand (Line 8) provides the total class average and excess demand values (Line 9). These values are the basis for determining the ultimate allocation percentage for each class on Line 10.

Q. Has the Company used the A&E method in other proceedings?

A. Yes, the Company has used the A&E method in every rate proceeding for the Virginia jurisdiction since 1972, and this methodology provides an accepted and understood approach for allocating costs. The Company has also included the A&E method in North Carolina filings in both the 1992 Rate Case and the

2019 Rate Case. In the 1992 Rate Case, the Company proposed usage of the A&E method at the North Carolina class level for the allocation of North Carolina Jurisdictional costs to the customer classes. In the 2019 Rate Case, the Company provided jurisdictional and North Carolina class allocation factors developed using the A&E method, but a cost of service study was not performed using these factors.

Q. In the calculation of the A&E factor, has the Company considered the same adjustments to demand and energy as it did for the calculation of the SWPA factor?

A. Yes. The Company considered the same adjustments to demand and energy described earlier, specifically the adjustments to the summer and winter peak demands to recognize generation from certain non-utility generators that decrease load that is measured on the Company's transmission system.

Q. Are there any aspects of the A&E method that warrant further consideration?

A. Yes. Because the A&E method uses non-coincident peak demands for each jurisdiction or customer class, customers that may curtail during the Company's periods of highest demand will be allocated their portion of excess demand based on a non-coincident peak demand that does not reflect such curtailment. This concern is especially meaningful for customer classes with a limited number of customers, where an individual customer's curtailment or lack thereof may have significant impacts on the class coincident peak demand.

In the present case, the Schedule NS and 6VP customer classes both contain customers that frequently curtail load during the Company's periods of highest demand. Under the A&E method, the Schedule NS class's non-coincident peak demand is 171.7 MW, whereas under the SWPA method, Schedule NS's average peak demand is 34.4 MW. Likewise, the 6VP class's non-coincident peak demand is 70.3 MW under the A&E method, while the average peak demand is 30.4 MW under the SWPA method. While each customer class does have a non-coincident peak demand higher than its average peak demand, these two classes stand out given that the non-coincident peaks are more than double the average peak demand amounts.

The ability of a large customer to curtail its load at high-demand hours can be beneficial not only to the customer itself but also to the broader jurisdiction and even to the Company's overall system. In order to address this concern, the Company has prepared two versions of the A&E allocation factor calculation. The first follows the methodology described above with no modification (which I will refer to as the "A&E Baseline" study), while the second version contains a modification to the non-coincident peak demand of the Schedule NS and 6VP customer classes (and which I will refer to as the "Modified A&E" study). In this second version, the non-coincident peak demand amounts for these two classes are set equal to each class's respective average demand, resulting in zero percent of the excess demand component being allocated to either the Schedule NS or the 6VP class.

Q. Based upon the adjustments you just described, can you provide the A&E factor for the North Carolina customer classes?

A. The A&E Baseline information is provided in my Schedule 3, pages 1-2. The Modified A&E information is provided in my Schedule 4, pages 1-2.

IV. COST ALLOCATION – ALLOCATION OF DISTRIBUTION PLANT COSTS

Q. Was a specific allocation method, such as SWPA, used with respect to distribution costs?

A. No. Unlike production and transmission plant, distribution plant is first assigned to the state in which the asset is located. Then, once assigned to a state (i.e., Virginia or North Carolina), the distribution plant is allocated to customers within that state based on class peak demands, non-coincident peak demands, and the numbers of customers at the different distribution voltages. Distribution expenses related to plant are allocated on allocation factors derived from the related plant account. Other distribution customer service expenses are allocated on appropriate factors related to such things as the number and type of customers and retail revenue.

Q. Why are distribution plant-related costs allocated differently than production and transmission plant related costs?

A. Whereas production plant and transmission plant related costs are more applicable to the Company's overall electric system and thus can have customer contributions appropriately captured in a single allocation factor, different customers require different levels of distribution plant and related costs, varying depending on the number of customers, the non-coincident demand of the customer, and the level of voltage at which the customer receives service. Different allocation factors are applied to portions of each distribution FERC account. For example, in FERC Account 364, the Primary Demand portion of the account is allocated on Factor 9, which is based on the class peak demands at overhead primary level. The Primary Customer portion is allocated on Factor 17, which is based on the total number of customers excluding customers receiving service at transmission level. The Secondary Demand portion is allocated on Factor 10, which is based on the non-coincident demands for overhead secondary level. The Secondary Customer portion is allocated Factor 18, which is based on the number of customers using overhead secondary. By applying different factors to each of these different portions of the FERC account, the cost of service better reflects how the customers cause those distribution costs to be incurred.

Q. How are the various divisions of distribution plant within each FERC Account determined?

A. The Company's records specify distribution plant by FERC account and by state. In order to more accurately allocate distribution plant and related costs to the customers causing those costs to be incurred, the Company's cost of service study splits these distribution plant FERC account amounts between customer and demand portions, as well as primary and secondary portions and overhead and underground portions, where relevant.

The split between customer and demand portions is determined by the Company's distribution model, which uses a minimum system methodology to determine the customer portion of each distribution FERC account. For FERC accounts where a split between primary and secondary is necessary, the Company uses percentages based on distribution system data.

Q. Please explain how the minimum system method works.

A. The minimum system method operates under the assumption that regardless of level of demand, a certain level of distribution plant infrastructure is necessary to connect any customer to the energy grid and provide service to that customer. This base level of distribution plant is considered to be the minimum system and would be considered the customer component. Any portion of distribution plant above this minimum would then be the demand component. For example, within the Company's model, the minimum system component for Account 364 is a 35' pole. The Company has a massed item file that provides both historic cost information for the combined number of 35' poles on the system and a total number of poles in account 364. The total number of poles is multiplied by the average cost of a 35' pole, and the resulting amount represents the value of plant in Account 364 associated with the customer component. The remaining amount left in Account 364 is thus the demand component.

Q. Does the Company feel that minimum system is the best method for determining the customer and demand portions of distribution plant?

A. Yes. The Company has used a minimum system-based approach in examining its distribution plant for more than 40 years. Minimum system methodology produces reasonable, replicable results, and it has been used to develop and support the rates currently approved by the Commission. While there may be some updates and modifications over time as the standards of what constitutes a minimum system change, the minimum system method is both historically supported and conceptually sound, and the Company supports its continued use.

V. SUMMARY OF COST OF SERVICE SCHEDULES AND FORM E-1, ITEM 45

Q. Please summarize the results of DENC's Cost of Service Studies.

A. Company Exhibit REM-1, Schedule 5 provides a summary of the fully distributed "per books" jurisdictional and customer class cost of service studies based on the SWPA allocation method for the 12-months ended December 31, 2023 ("test year").

A summary of the four jurisdictions served by the Company is included in Pages 1-2. For the North Carolina jurisdiction, the overall "booked" rate of return for 2023 was 5.4364%. Pages 3-4 provide the summary for all of the North Carolina customer classes.

Company Exhibit REM-1, Schedule 6 provides the effects of annualizing the base rate non-fuel revenues for each customer class. Annualized revenue is determined by billing all customers on the rates on which they were billed at the end of the test year.

Company Exhibit REM-1, Schedule 7 shows the fully adjusted cost of service for each class. The fully adjusted cost of service shows, for each class, a class rate of return that takes into account the class effects of each ratemaking adjustment and also the proposed revenue increases.

Company Exhibit REM-1, Schedule 8 provides a summary of the information provided in Schedules 5-7.

Company Exhibit REM-1, Schedule 9 provides, for each customer class, the customer, demand, and energy related classifications and functions based on per books, annualized revenues, and proposed revenues in this proceeding.

Company Exhibit REM-1, Schedule 10 provides, for each component shown in Company Exhibit REM-1, Schedule 9, "unit costs" for each class based on annualized base rate revenue, fully adjusted base rate revenues, and proposed base rate revenues at an equalized rate of return. These unit costs are categorized into Production (demand and energy), Transmission, Distribution, Energy (excluding fuel), and Customer.

Note that all cost of service studies supporting the information in Schedules 5-10 have been performed using the SWPA allocation methodology.

Q. How should the unit costs identified in your Schedule 10 be used in the development of actual rates?

A. The unit costs were provided to Company Witness Givens for his review in designing rates, but the unit costs should only be viewed as a "guide" in setting actual rates. There are many other considerations in the development of individual class revenue requirements and resultant rate schedule pricing.

Q. Has the Company used the other allocation methodologies discussed above to produce similar studies as those shown in Schedules 5-10?

A. Yes, the Company has produced similar schedules for the SWCP, the A&E Baseline, and the Modified A&E methodologies. Company Exhibit REM-1, Schedules 11-16 show the equivalent information for studies using the SWCP methodology at the North Carolina class level as is shown, for the SWPA methodology, in my Schedules 5-10. The one difference is that Schedule 11 does not contain a jurisdictional cost of service study, as that study would be the same as the one provided in my Schedule 5 given that in both cases the jurisdictional study has been performed using the SWPA allocation methodology.

Company Exhibit REM-1, Schedules 17-22 show the equivalent information for studies using the A&E Baseline methodology at the North Carolina class level. Again, the one difference is that Schedule 17 does not contain a jurisdictional cost of service study, as that study would be the same as the one provided in my Schedule 5 given that in both cases the jurisdictional study has been performed using the SWPA allocation methodology.

Company Exhibit REM-1, Schedules 23-28 show the equivalent information for studies using the Modified A&E methodology at the North Carolina class level. Again, the one difference is that Schedule 23 does not contain a jurisdictional cost of service study, as that study would be the same as the one provided in my Schedule 5 given that in both cases the jurisdictional study has been performed using the SWPA allocation methodology.

Q. Having produced each of these four class cost of service studies, does the Company have a recommendation as to which cost allocation methodology should be used?

A. I have provided the results of each of the four methodologies to Company Witness Givens for his evaluation in terms of rate design. Given that these different methodologies only applied at the class level, there is no difference in revenue requirement under consideration, so each of these four methodologies only informs the apportionment of the revenue requirement amount between the customer classes. Company Witness Givens discusses the considerations given to each method in his testimony. Tables 1 through 4, below, summarize the results of the Fully Adjusted Cost of Service study as provided to Company Witness Givens.

TABLE 1 - FULLY ADJUSTED COST RESULTS USING SWPA ALLOCATION METHODOLOGY

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$61,939,239	$39,281,392	$12,733,509	$5,132,276	$3,523,732	$1,191,949	$69,834	$6,547
Rate Base	$1,330,125,491	$696,222,134	$265,887,221	$145,058,094	$123,220,232	$64,825,046	$34,692,015	$220,750
ROR	4.6566%	5.6421%	4.7891%	3.5381%	2.8597%	1.8387%	0.2013%	2.9657%
Index		1.21	1.03	0.76	0.61	0.39	0.04	0.64

TABLE 2 - FULLY ADJUSTED COST RESULTS USING SWCP ALLOCATION METHODOLOGY

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$61,939,240	$31,064,235	$12,424,838	$7,199,057	$8,842,687	$2,094,720	$306,136	$7,567
Rate Base	$1,330,125,491	$800,010,254	$269,769,715	$118,974,000	$56,020,257	$53,432,045	$31,711,691	$207,529
ROR	4.6566%	3.8830%	4.6057%	6.0510%	15.7848%	3.9203%	0.9654%	3.6462%
Index		0.83	0.99	1.30	3.39	0.84	0.21	0.78

TABLE 3 - FULLY ADJUSTED COST RESULTS USING A&E BASELINE ALLOCATION METHODOLOGY

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$61,939,239	$42,160,836	$12,284,929	$6,185,878	$846,217	$515,156	($61,655)	$7,878
Rate Base	$1,330,125,491	$659,956,973	$271,535,534	$131,761,654	$156,945,947	$73,368,201	$36,353,636	$203,546
ROR	4.6566%	6.3884%	4.5242%	4.6947%	0.5392%	0.7022%	-0.1696%	3.8703%
Index		1.37	0.97	1.01	0.12	0.15	-0.04	0.83

TABLE 4 - FULLY ADJUSTED COST RESULTS USING MODIFIED A&E ALLOCATION METHODOLOGY

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$61,939,239	$38,944,088	$10,825,267	$5,916,538	$4,267,116	$2,075,789	($97,311)	$7,752
Rate Base	$1,330,125,491	$700,556,479	$289,958,358	$135,161,075	$113,769,794	$53,670,993	$36,803,653	$205,139
ROR	4.6566%	5.5590%	3.7334%	4.3774%	3.7507%	3.8676%	-0.2644%	3.7787%
Index		1.19	0.80	0.94	0.81	0.83	-0.06	0.81

Q. You stated earlier that you are sponsoring Item 45 (a – f) of the Form E1, Rate Case Information Report – Electric Companies in this proceeding. Please explain what information is required to be included in Item 45.

A. Item 45 includes the jurisdictional and class cost of service information required in rate filings for electric utilities like the Company. The instructions for Form E-1 Item 45 have six subparts pertaining to fully distributed cost of service studies for the test year. I am sponsoring the following in response to the Form E-1 Item 45 instructions:

i) Item 45a provides fully distributed "per books" jurisdictional and customer class cost of service studies for the 12-months ended December 31, 2023 ("test year"). The jurisdictional cost of service study utilizes the SWPA allocation methodology, and two class cost of service studies are shown; one using the SWPA allocation methodology and the other using the SWCP allocation methodology. Summaries of the results of these studies are provided in Company Exhibit REM-1, Schedules 5 and 11, respectively. All subsequent cost of service studies discussed in the following items will be based upon the SWPA allocation method at the jurisdictional level and either SWPA or SWCP allocation methodology for the North Carolina class studies, with SWPA listed first and SWCP listed second.

ii) Item 45b provides “per books” jurisdiction and customer class Rate of Return Statements with base rate non-fuel revenue annualized for the test year based upon rates in effect as of January 1, 2024. This information is also provided in Company Exhibit REM-1, Schedules 6 and 12 for each of the respective allocation methodologies.

iii) Item 45c provides fully adjusted jurisdictional and customer class Rate of Return Statements based on the cost of service studies provided in Item 45a. These cost of service studies were adjusted for all of the accounting adjustments used in the development of the proposed revenue requirement. These adjustments were allocated to each customer class consistent with the way costs were allocated in the class cost of service study provided in response to Item 45a. Summaries of the results, by jurisdiction and each class, are shown in Company Exhibit REM-1, Schedules 7 and 13.

iv) Item 45d provides, for each customer class, the customer, demand, and energy related classifications and functions based on per books, annualized revenues, and proposed revenues in this proceeding. Summaries are provided in Company Exhibit REM-1, Schedules 9 and 15. Part A provides the total customer class per books cost of service identified by “Customer,” “Production Demand,” “Production Energy,” “Production Combined,” “Transmission,” “Distribution,” and “Energy.” The “Production Demand” component represents the portion of production costs and facilities that are allocated based on the “demand” portion of the SWPA or SWCP production allocation factor, while the “Production Energy” component represents the portion of production costs and facilities that are allocated on the “energy” portion of the SWPA or SWCP production allocation factor. Part B shows each component’s rate of return based on annualized revenue. The total annualized revenue adjustment was spread to each component based on the relationship of each component’s booked operating income to booked total operating income from Part A. Spreading the adjustment in this fashion assures that each component will have the same rate of return as the overall class rate of return based on annualized revenue. Part C shows each component’s rate of return based on a fully adjusted cost of service including the proposed revenue increase. The revenue increase was spread in the same manner as the annualized revenue adjustment in Part B as described above. The final total rate base was spread to each component based on the relationship of each component’s booked rate base to total booked rate base from Part A. The end result is that each component has the same rate of return as the overall class rate of return based on proposed revenue.

v) For each component in Item 45d, Item 45e provides “unit costs” based on annualized revenue, fully adjusted revenues, and proposed rates at an equalized rate of return. This is accomplished by first adjusting the booked rate revenue for each function from Part A to remove fuel revenues and rider revenues as well as base rate revenue components not directly related to the billing units used to calculate the “unit costs” (facilities charges and load management credits). The remaining base rate revenue amount is then adjusted for the annualized revenue adjustment (Part B), the proposed ratemaking adjustments (Part C), and proposed revenue increase (Part D). These revenue adjustments and increases are spread amongst the components on the basis of the ratio of component net operating income to total net operating income, as in Item 45d. The adjustment or increase amount is then added to the original booked rate revenue to get the annualized revenue amount (in Part B), the fully adjusted revenue amount (Part C), or the proposed revenue amount (in Part D). At this point, each component is at the same rate of return as the overall rate of return for the class (equalized rate of return). The resulting rate revenue is divided by the billing units to achieve unit costs for each customer class. For the Residential, Small General Service and County / Municipal, Outdoor and Street Lights, and Traffic classes, the billing units for all but the customer charges are based on kWhs. For the Large General Service, Schedule NS, and 6VP classes, transmission and distribution demand are based on kW demand billing units, energy-related costs are based on kWh, and production demand units are based on either kW demand or kWh depending on the structure of the relevant rates in place for each class. This information is also provided in Company Exhibit REM-1, Schedules 10 and 16, respectively.

vi) Item 45f provides workpapers supporting the derivation of allocation factors used in the jurisdictional and customer class cost of service studies in Item 45 (a – e).

VI. ADDITIONAL COST ALLOCATION AND COST OF SERVICE TOPICS

Q. Do you have any other items pertaining to cost allocation and the cost of service study to address?

A. Yes. In recent years, the Company has experienced significant load growth related to a number of new large, high-load factor customers coming into the Company's Virginia service territory. With this growth has come the question of whether the increased cost incurred to serve these customers has caused the Company's North Carolina jurisdiction to be impacted either positively or negatively. There is the potential for a positive impact for the North Carolina jurisdiction to the extent that the growth in Virginia customer load and usage causes the Company's demand and energy allocation factors to allocate more cost to Virginia and, correspondingly given that the allocation factor will always add to 100%, less to North Carolina, increasing the overall rate of return for North Carolina. There is potential for a negative impact for the North Carolina jurisdiction to the extent that the costs incurred to serve that growth have increased, should North Carolina's allocated share of those costs be greater than any cost reductions resulting from decreased allocation percentages.

Q. Is it possible to determine if the impact of this customer growth and usage in the Company's Virginia service territory has been positive or negative for North Carolina jurisdiction?

A. Making such a determination is very challenging. The Company's operations are not static, so while this particular customer growth has been very impactful, the costs associated with serving that particular customer growth are not the only new costs the Company has incurred during this period of time. In addition, there are numerous factors that contribute to the Company's cost of service that are not necessarily related to the addition of new customers including, for example, replacing plant that has reached the end of its useful life. As discussed above, most of these costs are tracked at a system level, and they are subsequently allocated to the Company's jurisdictions using appropriate allocation factors; attempting to pull out costs specific to one region's growth and isolate those from all other costs would not really be feasible under the Company's current cost of service approach.

Acknowledging this difficulty, there are some methods to measure potential impacts on North Carolina. The first involves evaluating the change over time in the North Carolina jurisdiction allocation percentage for Factors 1, 2, and 3. Tables 5-7 below shows the North Carolina jurisdiction percentages for each of these three factors, taken from the Company's cost of service studies in its prior three rate cases (test years 2011, 2015, and 2018) and also from the Company's cost of service studies in 2019, 2020, 2021, 2022, and 2023.

Table 5 - Jurisdictional Factor 1 Percentages 2011-2023

	System	VA Juris	VA Non	FERC	NC Juris
2011	100.0000%	80.0350%	11.9310%	3.2455%	4.7885%
2015	100.0000%	80.4473%	11.5121%	2.9240%	5.1166%
2018	100.0000%	81.2469%	12.1072%	1.6952%	4.9507%
2019	100.0000%	80.6154%	11.9381%	2.8255%	4.6210%
2020	100.0000%	80.9434%	12.5439%	1.6340%	4.8787%
2021	100.0000%	81.8483%	11.7942%	1.5848%	4.7727%
2022	100.0000%	83.0698%	11.0260%	1.4748%	4.4294%
2023	100.0000%	83.5642%	10.7958%	1.4461%	4.1939%

Table 6 - Jurisdictional Factor 2 Percentages 2011-2023

	System	VA Juris	VA Non	FERC	NC Juris
2011	100.0000%	70.0758%	10.4352%	15.2998%	4.1892%
2015	100.0000%	69.9865%	10.0005%	15.5638%	4.4492%
2018	100.0000%	69.0018%	10.2671%	16.5287%	4.2024%
2019	100.0000%	68.1665%	10.0820%	17.8470%	3.9045%
2020	100.0000%	65.2439%	10.1185%	20.7031%	3.9345%
2021	100.0000%	65.6768%	9.4734%	21.0178%	3.8320%
2022	100.0000%	67.0408%	8.9064%	20.4772%	3.5756%
2023	100.0000%	66.7957%	8.6431%	21.2070%	3.3542%

Table 7 - Jurisdictional Factor 3 Percentages 2011-2023

	System	VA Juris	VA Non	FERC	NC Juris
2011	100.0000%	78.4879%	13.0486%	3.3533%	5.1102%
2015	100.0000%	78.6166%	12.8658%	3.2852%	5.2324%
2018	100.0000%	79.4608%	13.6333%	1.8135%	5.0924%
2019	100.0000%	78.5995%	13.4139%	3.0734%	4.9132%
2020	100.0000%	79.6338%	13.4589%	1.8119%	5.0954%
2021	100.0000%	80.5824%	12.6975%	1.7580%	4.9621%
2022	100.0000%	81.5484%	12.2960%	1.6532%	4.5024%
2023	100.0000%	82.3069%	11.8146%	1.5891%	4.2894%

As seen in Tables 5-7, the North Carolina jurisdiction's allocation percentages for each of these three allocation factors have decreased over time. This means that, of the Company's total costs, North Carolina receives a smaller percentage, with the Company's other jurisdictions receiving a greater percentage of the overall total costs. Based solely on the allocation factors, North Carolina has thus seen a benefit to the growth in the Company's Virginia service territory. Of course, the allocation factors do not address whether there have been increased system costs and whether North Carolina jurisdiction is receiving a larger amount of costs, despite receiving a smaller allocation.

Q. Is there a way to assess both the change in system costs and the change in allocation percentages for North Carolina jurisdiction?

A. As I have previously described, the cost of service studies contain functionalized amounts for production, transmission, and distribution. While production and transmission costs are allocated on a system-wide basis, distribution plant is assigned by state prior to be allocating to customers within the assigned state. Table 8, below, shows the plant in service for each of these three functional categories, from 2018, the test year for the Company's 2019 rate case, to 2023, for all jurisdictions, excluding ringfenced amounts. The bottom of Table 8 also shows the change in North Carolina jurisdiction plant for each of the three functions.

Table 8 - Change in Plant - 2018 vs. 2023

	System	VA Juris	VA Non	FERC	NC Juris
Production Plant					
2018	19,111,509,231	15,405,629,611	2,348,567,601	338,846,338	1,018,465,681
2023	18,512,012,131	15,319,568,292	2,035,692,331	283,258,920	873,492,588
Transmission Plant					
2018	9,362,291,201	6,500,944,123	974,485,922	1,487,374,948	399,486,208
2023	14,296,049,055	9,642,901,022	1,251,816,236	2,914,707,674	486,624,123
Distribution Plant					
2018	11,720,177,985	9,808,130,088	1,241,235,865	78,280,777	592,531,255
2023	15,954,712,566	13,529,930,819	1,571,649,432	103,934,214	749,198,101

North Carolina Jurisdiction Change in Plant (2023 minus 2018)

Production	Transmission	Distribution
(144,973,093)	87,137,915	156,666,846

While there are many factors that contribute to the change in these numbers from 2018 to 2023, the plant allocation impacts show above certainly do not give a signal that North Carolina is being negatively impacted by costs associated with customer growth in Virginia. North Carolina distribution plant has increased by more than North Carolina's allocated share of production and transmission plant, which suggests that costs specific to North Carolina are driving much of the related plant cost. Indeed, as also suggested by the allocations in Tables 5 through 7, the growth in Virginia may be providing an overall benefit to North Carolina customers by providing a reduction in allocation greater than the costs associated with this customer and load growth.

Q. Has the Commission directed the Company to address any other items related to cost allocation or cost of service studies in this proceeding?

A. Yes. In its *Order Approving Revised Interconnection Standard and Requiring Reports and Testimony* issued June 14, 2019 ("Interconnection Order"), the Commission, in addressing interconnection issues and the impact of distributed generation resources on existing utility distribution grids, directed the Company to file testimony in their next general rate cases addressing the benefits that distributed generators receive from the their systems, estimating the distributed resources' share of the related costs, and providing options for recovering those costs from distributed generators.[3]

Q. How will your testimony address this topic?

A. While many of the matters addressed in the Interconnection Order are outside of my area of expertise, I will address the request to estimate distributed generator's share of related costs and to explain the impact that shifting these costs to distributed generators would have on other customers classes. The costs in question primarily involve the Company's distribution system, as these distributed generation resources are mostly connected to the Company's distribution grid and utilize the grid to distribute their generation output. While it is my understanding that distributed generators are billed for distribution upgrades made specifically to connect those customers to the Company's system, the matter at question here is whether the activity of these distributed generation customers creates additional distribution costs that are

[3] Interconnection Order at 64, 66, Docket No. E-100, Sub 101.

not necessarily readily apparent or quantifiable at the time of interconnection, and if so, whether those costs are being adequately recovered from the distributed generator or whether they are being passed on to other customers.

Q. Please explain how you have evaluated these distribution costs as they relate to distributed generation customers.

A. In order to address this issue, the Company has prepared an additional North Carolina class cost of service study. This study, summarized in my Schedule 29, attempts to set the highest-end estimate of the cost distributed generators are imposing on the Company's distribution system. This is done by treating the generation produced by these customers as if it were demand required of these customers and adjusting the Company's distribution demand allocation factors to reflect that assumption. In this way, this study treats any usage of the grid, whether to deliver energy to a customer or to transport energy generated by a customer, as an equivalent usage and thus allocate distribution plant costs based on total kW on the grid, regardless of which way that kW is flowing.

This study is being used to place an upper band estimate on any potential cost shifting being caused by distributed generators. Because this analysis treats all activity on the distribution grid, regardless of direction of flow, as equally contributing to the costs of the distribution system, the study may not reflect the actual costs associated with these customers but instead represents a potential maximum possible cost-shift estimate. The Company proposes to continue to investigate the potential cost allocation impacts of distributed generators and present methods to address the shift in future dockets.

VIII. TERMS AND CONDITIONS

Q. Are you sponsoring any proposed changes to the Company's terms and conditions?

A. Yes. I am sponsoring the Company's proposed update to its AMI Opt-Out Policy. As discussed by Company Witness Kevin L. Fields, the Company is currently in the process of converting existing customer meters to AMI Meters ("smart meters"). When a customer opts out of smart meter installation or requests to replace their existing smart meter with a non-communicating meter, the Company must expend additional resources both initially and on an ongoing basis. Up front, there are administrative expenses associated with a customer's initial decision to opt out of smart meter installation, such as program administration and reporting, customer communications and account management, work order generation and scheduling, and inventory management and shipping. The Company must also exchange the customer's existing meter for an opt-out meter and send someone to read the non-communicating meter manually on a monthly basis.

Q. What is the Company's current opt-out practice for smart meters?

A. Currently, qualifying residential customers (defined as residential customers on Rate Schedule 1 who have accounts in good standing and who do not participate in net metering) are allowed to opt out of smart meter installation upon request and at no expense. These customers receive an information packet explaining the benefits of AMI that they would forego by opting out. The customer is required to complete and return forms confirming their acknowledgement that opting out at no expense is an interim solution until the Company has an opt-out policy approved by the Commission.

Q. **Please describe the AMI opt-out policy the Company is proposing in this proceeding.**

A. Under the Company's proposed opt-out policy, qualifying residential customers will be eligible to opt out of smart meter installation upon request. The Company will not charge a one-time initial fee for the installation of the non-communicating meter but will impose an ongoing monthly fee of $30.88, intended to recover the labor and administrative costs associated with the monthly meter reading.

If approved, the Company proposes to send all current interim opt-out customers a letter informing them of the opt-out policy and associated monthly fee. These customers will have the option to opt into AMI at no charge, or they will be transitioned to the approved opt-out program where ongoing fees will be applied to their account effective February 1, 2025.

Q. Does this conclude your direct testimony?

A. Yes, it does.

APPENDIX A

BACKGROUND AND QUALIFICATIONS OF ROBERT E. MILLER

Robert E. Miller received a Bachelor of Arts degree in English Literature and Philosophy from the University of Virginia in 2007. He received a post-baccalaureate undergraduate certificate in accounting from Virginia Commonwealth University in 2015. Mr. Miller is also a Certified Public Accountant in Virginia.

Mr. Miller joined the Customer Rates Department in 2015, beginning as an intern and then becoming a full-time employee as a Regulatory Analyst I in 2016, working with the Company's cost of service model. In June of 2022, Mr. Miller was promoted to his current position as a Manager – Regulation. His job duties include the calculation of distribution plant-related allocation factors and the preparation of cost of service studies for the Company's Virginia and North Carolina regulated customers and the Company's Non-Jurisdictional customers.

Mr. Miller has previously presented testimony before the North Carolina Utilities Commission and Virginia State Corporation Commission.

Dominion Energy North Carolina
Summer Winter Peak and Average Factors
12 months ended 12/31/2023

Factor 1/61

	Total System	VA Juris	Va Non-Juris	FERC	NC Juris
(1) Energy - Production	93,581,866	77,024,299	11,056,327	1,487,136	4,014,104
(2) Avg. Demand	10,682,861	8,792,728	1,262,138	169,764	458,231
(3) Avg. Demand as % of Total	100.0000%	82.3069%	11.8146%	1.5891%	4.2894%
(4) Winter Coincident Peak	15,818,880	13,623,059	1,307,494	191,689	696,637
(5) Summer Coincident Peak	18,519,392	15,782,498	1,823,426	223,979	689,489
(6) Avg. Peak Demand	17,169,136	14,702,778	1,565,460	207,834	693,063
(7) Avg. Peak Demand as % of Total	100.0000%	85.6349%	9.1179%	1.2105%	4.0367%
(8) Avg. Demand / Avg. Peak Demand	62.2213%	51.2124%	7.3512%	0.9888%	2.6689%
(9) 1 - Avg. Demand / Avg. Peak Demand	37.7787%	32.3518%	3.4446%	0.4573%	1.5250%
(10) Factor 1	100.0000%	83.5642%	10.7958%	1.4461%	4.1939%
		0.0000%	0.0000%	0.0000%	0.0000%
(11) **Factor 1**	**100.0000%**	**83.5642%**	**10.7958%**	**1.4461%**	**4.1939%**

Dominion Energy North Carolina
Summer Winter Peak and Average Factors
12 months ended 12/31/2023

Factor 2

	Total System	VA Juris	Va Non-Juris	FERC	NC Juris
(1) Energy - Production	117,651,581	77,024,299	11,056,327	25,556,852	4,014,104
(2) Avg. Demand	13,430,546	8,792,728	1,262,138	2,917,449	458,231
(3) Avg. Demand as % of Total	100.0000%	65.4681%	9.3975%	21.7225%	3.4119%
(4) Winter Coincident Peak	19,774,820	13,623,059	1,307,494	4,147,629	696,637
(5) Summer Coincident Peak	22,801,881	15,782,498	1,823,426	4,506,468	689,489
(6) Avg. Peak Demand	21,288,351	14,702,778	1,565,460	4,327,049	693,063
(7) Avg. Peak Demand as % of Total	100.0000%	69.0649%	7.3536%	20.3259%	3.2556%
(8) Avg. Demand / Avg. Peak Demand	63.0887%	41.3030%	5.9288%	13.7044%	2.1525%
(9) 1 - Avg. Demand / Avg. Peak Demand	36.9113%	25.4927%	2.7143%	7.5026%	1.2017%
(10) Factor 2	100.0000%	66.7957%	8.6431%	21.2070%	3.3542%
		0.0000%	0.0000%	0.0000%	0.0000%
(11) **Factor 2**	**100.0000%**	**66.7957%**	**8.6431%**	**21.2070%**	**3.3542%**

Dominion Energy North Carolina
Summer Winter Peak and Average Factors
12 months ended 12/31/2023

FACTOR 1/61

	Total	Residential	SGS	LGS	6VP	Sch NS	St & Outdoor	Traffic
(1) Energy - Production	4,014,104	1,598,359	783,014	598,259	268,137	741,825	24,082	428
(2) Avg. Demand	458,231	182,461	89,385	68,294	30,609	84,683	2,749	49
(3) Avg. Demand as % of Total	80.9089%	39.8186%	19.5066%	14.9039%	6.6799%	18.4805%	0.5999%	0.0107%
(4) Winter Coincident Peak	696,637	423,479	134,083	66,125	23,721	49,176	0	54
(5) Summer Coincident Peak	689,489	417,788	147,167	67,695	37,084	19,699	0	56
(6) Avg. Peak Demand	693,063	420,633	140,625	66,910	30,403	34,437	0	55
(7) Avg. Peak Demand as % of Total	100.0000%	60.6919%	20.2904%	9.6542%	4.3867%	4.9688%	0.0000%	0.0080%
(8) Avg. Demand / Avg. Peak Demand	62.2213%	24.7756%	12.1372%	9.2734%	4.1563%	11.4988%	0.3733%	0.0066%
(9) 1 - Avg. Demand / Avg. Peak Demand	37.7787%	22.9286%	7.6654%	3.6472%	1.6572%	1.8772%	0.0000%	0.0030%
(10) Factor 1	99.9999%	47.7042%	19.8027%	12.9207%	5.8135%	13.3759%	0.3733%	0.0096%
		0.0001%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
(11) **Factor 1**	**100.0000%**	**47.7043%**	**19.8027%**	**12.9207%**	**5.8135%**	**13.3759%**	**0.3733%**	**0.0096%**

Dominion Energy North Carolina
Summer Winter Peak and Average Factors
12 months ended 12/31/2023

FACTOR 2

	Total	Residential	SGS	LGS	6VP	Sch NS	St & Outdoor	Traffic
(1) Energy - Production	4,014,104	1,598,359	783,014	598,259	268,137	741,825	24,082	428
(2) Avg. Demand	458,231	182,461	89,385	68,294	30,609	84,683	2,749	49
(3) Avg. Demand as % of Total	80.9089%	39.8186%	19.5066%	14.9039%	6.6799%	18.4805%	0.5999%	0.0107%
(4) Winter Coincident Peak	696,637	423,479	134,083	66,125	23,721	49,176	0	54
(5) Summer Coincident Peak	689,489	417,788	147,167	67,695	37,084	19,699	0	56
(6) Avg. Peak Demand	693,063	420,633	140,625	66,910	30,403	34,437	0	55
(7) Avg. Peak Demand as % of Total	100.0000%	60.6919%	20.2904%	9.6542%	4.3867%	4.9688%	0.0000%	0.0080%
(8) Avg. Demand / Avg. Peak Demand	63.0887%	25.1210%	12.3064%	9.4027%	4.2142%	11.6591%	0.3785%	0.0067%
(9) 1 - Avg. Demand / Avg. Peak Demand	36.9113%	22.4022%	7.4894%	3.5635%	1.6192%	1.8341%	0.0000%	0.0029%
(10) Factor 2	100.0000%	47.5232%	19.7959%	12.9662%	5.8334%	13.4931%	0.3785%	0.0097%
		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
(11) **Factor 2**	**100.0000%**	**47.5232%**	**19.7959%**	**12.9662%**	**5.8334%**	**13.4931%**	**0.3785%**	**0.0097%**

Dominion Energy North Carolina
Summer Winter Coincident Peak Factors
12 months ended 12/31/2023

FACTOR 1/61

	Total	Residential	SGS	LGS	6VP	Sch NS	St & Outdoor	Traffic
(1) Energy - Production	4,014,104	1,598,359	783,014	598,259	268,137	741,825	24,082	428
(2) Avg. Demand	0	0	0	0	0	0	0	0
(3) Avg. Demand as % of Total	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
(4) Winter Coincident Peak	696,637	423,479	134,083	66,125	23,721	49,176	0	54
(5) Summer Coincident Peak	689,489	417,788	147,167	67,695	37,084	19,699	0	56
(6) Avg. Peak Demand	693,063	420,633	140,625	66,910	30,403	34,437	0	55
(7) Avg. Peak Demand as % of Total	100.0000%	60.6919%	20.2904%	9.6542%	4.3867%	4.9688%	0.0000%	0.0080%
(8) Avg. Demand / Avg. Peak Demand	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
(9) 1 - Avg. Demand / Avg. Peak Demand	100.0000%	60.6919%	20.2904%	9.6542%	4.3867%	4.9688%	0.0000%	0.0080%
(10) Factor 1	100.0000%	60.6919%	20.2904%	9.6542%	4.3867%	4.9688%	0.0000%	0.0080%
		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
(11) **Factor 1**	**100.0000%**	**60.6919%**	**20.2904%**	**9.6542%**	**4.3867%**	**4.9688%**	**0.0000%**	**0.0080%**

Dominion Energy North Carolina
Summer Winter Coincident Peak Factors
12 months ended 12/31/2023

FACTOR 2

	Total	Residential	SGS	LGS	6VP	Sch NS	St & Outdoor	Traffic
(1) Energy - Production	4,014,104	1,598,359	783,014	598,259	268,137	741,825	24,082	428
(2) Avg. Demand	0	0	0	0	0	0	0	0
(3) Avg. Demand as % of Total	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
(4) Winter Coincident Peak	696,637	423,479	134,083	66,125	23,721	49,176	0	54
(5) Summer Coincident Peak	689,489	417,788	147,167	67,695	37,084	19,699	0	56
(6) Avg. Peak Demand	693,063	420,633	140,625	66,910	30,403	34,437	0	55
(7) Avg. Peak Demand as % of Total	100.0000%	60.6919%	20.2904%	9.6542%	4.3867%	4.9688%	0.0000%	0.0080%
(8) Avg. Demand / Avg. Peak Demand	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
(9) 1 - Avg. Demand / Avg. Peak Demand	100.0000%	60.6919%	20.2904%	9.6542%	4.3867%	4.9688%	0.0000%	0.0080%
(10) Factor 2	100.0000%	60.6919%	20.2904%	9.6542%	4.3867%	4.9688%	0.0000%	0.0080%
		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
(11) **Factor 2**	**100.0000%**	**60.6919%**	**20.2904%**	**9.6542%**	**4.3867%**	**4.9688%**	**0.0000%**	**0.0080%**

Dominion Energy North Carolina
A&E Baseline Factors
12 months ended 12/31/2023

Factor 1/61/1 NUC

		Total NC	Residential	SGS	LGS	6VP	NS	Street & Outdoor	Traffic
(1)	Loads at time of DOM LSE Peak	693,026	421,358	148,425	66,993	36,700	19,495	0	57
(2)	Jurisdictional peak loads	1,001,891	451,726	211,570	90,842	70,291	171,669	5,735	57
(3)	Kilowatt Hours (000)	4,014,104	1,598,359	783,014	598,259	268,137	741,825	24,082	428
(4)	Average load (kWh/24/Days in Year)	458,231	182,461	89,385	68,294	30,609	84,683	2,749	49
(5)	System Peak less average load (1-4)	234,795							
(6)	Jurisdictional peak less average load (2-4)	543,660	269,265	122,185	22,548	39,682	86,985	2,986	8
(7)	Ratio (5/6)	0.4319							
(8)	Allocation of excess (6x7)	234,795	116,290	52,769	9,738	17,138	37,567	1,290	3
(9)	Average load plus excess (4+8)	693,026	298,751	142,154	78,032	47,747	122,250	4,039	52
(10)	Factor 1	100.0001%	43.1082%	20.5121%	11.2597%	6.8897%	17.6401%	0.5828%	0.0075%
			-0.0001%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
(11)	**Factor 1**	**100.0000%**	**43.1081%**	**20.5121%**	**11.2597%**	**6.8897%**	**17.6401%**	**0.5828%**	**0.0075%**

Dominion Energy North Carolina
A&E Baseline Factors
12 months ended 12/31/2023

Factor 2

	Total NC	Residential	SGS	LGS	6VP	NS	Street & Outdoor	Traffic
(1) Loads at time of DOM Zone Peak	693,026	421,358	148,425	66,993	36,700	19,495	0	57
(2) Jurisdictional peak loads	1,001,891	451,726	211,570	90,842	70,291	171,669	5,735	57
(3) Kilowatt Hours (000)	4,014,104	1,598,359	783,014	598,259	268,137	741,825	24,082	428
(4) Average load (kWh/24/Days in Year)	458,231	182,461	89,385	68,294	30,609	84,683	2,749	49
(5) System Peak less average load (1-4)	234,795							
(6) Jurisdictional peak less average load (2-4)	543,660	269,265	122,185	22,548	39,682	86,985	2,986	8
(7) Ratio (5/6)	0.4319							
(8) Allocation of excess (6x7)	234,795	116,290	52,769	9,738	17,138	37,567	1,290	3
(9) Average load plus excess (4+8)	693,026	298,751	142,154	78,032	47,747	122,250	4,039	52
(10) Factor 2	100.0001%	43.1082%	20.5121%	11.2597%	6.8897%	17.6401%	0.5828%	0.0075%
		-0.0001%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
(11) **Factor 2**	**100.0000%**	**43.1081%**	**20.5121%**	**11.2597%**	**6.8897%**	**17.6401%**	**0.5828%**	**0.0075%**

Dominion Energy North Carolina
Modified A&E Factors
12 months ended 12/31/2023

Factor 1/61/1 NUC

	Total NC	Residential	SGS	LGS	6VP	NS	Street & Outdoor	Traffic
(1) Loads at time of DOM LSE Peak	693,026	421,358	148,425	66,993	36,700	19,495	0	57
(2) Jurisdictional peak loads	875,223	451,726	211,570	90,842	30,609	84,683	5,735	57
(3) Kilowatt Hours (000)	4,014,104	1,598,359	783,014	598,259	268,137	741,825	24,082	428
(4) Average load (kWh/24/Days in Year)	458,231	182,461	89,385	68,294	30,609	84,683	2,749	49
(5) System Peak less average load (1-4)	234,795							
(6) Jurisdictional peak less average load (2-4)	416,992	269,265	122,185	22,548	0	0	2,986	8
(7) Ratio (5/6)	0.5631							
(8) Allocation of excess (6x7)	234,795	151,615	68,799	12,696	0	0	1,681	4
(9) Average load plus excess (4+8)	693,026	334,076	158,184	80,990	30,609	84,683	4,431	53
(10) Factor 1	100.0000%	48.2054%	22.8251%	11.6865%	4.4167%	12.2193%	0.6393%	0.0077%
		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
(11) **Factor 1**	**100.0000%**	**48.2054%**	**22.8251%**	**11.6865%**	**4.4167%**	**12.2193%**	**0.6393%**	**0.0077%**

Dominion Energy North Carolina
Modified A&E Factors
12 months ended 12/31/2023

Factor 2

	Total NC	Residential	SGS	LGS	6VP	NS	Street & Outdoor	Traffic
(1) Loads at time of DOM Zone Peak	693,026	421,358	148,425	66,993	36,700	19,495	0	57
(2) Jurisdictional peak loads	875,223	451,726	211,570	90,842	30,609	84,683	5,735	57
(3) Kilowatt Hours (000)	4,014,104	1,598,359	783,014	598,259	268,137	741,825	24,082	428
(4) Average load (kWh/24/Days in Year)	458,231	182,461	89,385	68,294	30,609	84,683	2,749	49
(5) System Peak less average load (1-4)	234,795							
(6) Jurisdictional peak less average load (2-4)	416,992	269,265	122,185	22,548	0	0	2,986	8
(7) Ratio (5/6)	0.5631							
(8) Allocation of excess (6x7)	234,795	151,615	68,799	12,696	0	0	1,681	4
(9) Average load plus excess (4+8)	693,026	334,076	158,184	80,990	30,609	84,683	4,431	53
(10) Factor 2	100.0000%	48.2054%	22.8251%	11.6865%	4.4167%	12.2193%	0.6393%	0.0077%
		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
(11) **Factor 2**	**100.0000%**	**48.2054%**	**22.8251%**	**11.6865%**	**4.4167%**	**12.2193%**	**0.6393%**	**0.0077%**

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023

SCHEDULE 1

SCHEDULE 1 - SUMMARY

Line #		System	Va Juris	Va Non-Juris	FERC	N C Juris	Ringfenced Projects	Allocation Basis
1	Dec 2023							
2								
3	C:[SUMMARY OF RESULTS]							
4	D:[]							
5	E:[OPERATING REVENUES]	9,500,790,912	7,670,288,546	958,998,250	397,231,850	408,196,365	66,075,900	NC Schedule 2 - Revenue/Line 71
6	F:[]							
7	G:[OPERATING EXPENSES]							
8	H:[OPERATION & MAINTENANCE EXPENSES]	4,622,197,172	3,833,882,935	466,250,172	53,704,062	239,139,128	29,220,875	NC Schedule 3 - O&M Expense/Li
9	I:[DEPRECIATION EXPENSE]	1,447,333,125	1,117,573,348	144,148,465	76,002,111	60,832,913	48,776,289	NC Schedule 4 - Depreciation & A
10	J:[AMORT. OF ACQ. AJUSTMENTS]	217,980	145,601	18,840	46,227	7,311	0	NC Schedule 4 - Depreciation & A
11	K:[AMORT. OF PROP. LOSS & REG STUDY]	176,874,755	176,682,156	96,138	12,878	83,583	0	NC Schedule 6 - Net Current Inco
12	L:[REGULATORY DEBITS AND CREDITS]	301,229,648	243,547,075	45,624,274	1,149,210	10,909,089	0	NC Schedule 6 - Net Current Inco
13	N:[GAIN/LOSS ON DISPOSITION OF ALLOWANCES]	(2,077,000)	(1,709,514)	(245,389)	(33,006)	(89,091)	0	NC Schedule 6 - Net Current Inco
14	O:[GAIN / LOSS ON DISPOSITION OF PROPERTY]	5,606,459	4,435,410	561,419	364,388	245,242	0	NC Schedule 6 - Net Current Inco
15	Q:[ACCRETION EXPENSE - ARO]	126,939,746	104,149,691	13,995,118	1,881,285	5,133,919	1,779,732	NC Schedule 22 - Other Allocation
16	R:[FEDERAL INCOME TAX]							
17	S:[INVESTMENT TAX CREDIT - AMORTIZATION]	7,462,314	6,308,553	892,671	120,050	141,040	0	NC Schedule 7 - Income Tax Cr &
18	T:[FEDERAL NET CURRENT TAX]	(107,169,712)	95,855,467	32,956,820	4,023,576	6,833,874	(246,839,449)	NC Schedule 6 - Net Current Inco
19	U:[FEDERAL INCOME TAX DEFERRED]	358,785,375	96,032,897	(4,075,156)	29,087,735	(3,208,237)	240,948,136	NC Schedule 7 - Income Tax Cr &
20	W:[STATE INCOME TAX CURRENT]	8,532,564	17,073,071	2,288,552	2,309,198	483,103	(13,621,359)	NC Schedule 6 - Net Current Inco
21	X:[STATE INCOME TAX DEFERRED]	96,161,737	64,083,501	8,585,329	8,662,780	1,812,324	13,017,804	NC Schedule 7 - Income Tax Cr &
22	Y:[TAXES OTHER THAN INCOME TAX]	298,505,421	235,934,807	30,031,885	18,416,909	12,635,649	1,486,171	NC Schedule 5 - Other Taxes/Line
23	Z:[TOTAL ELECTRIC OPERATING EXPENSES]	7,340,599,584	5,993,994,997	741,129,137	195,747,403	334,959,847	74,768,200	
24	AA:[]							
25	AB:[NET OPERATING INCOME]	2,160,191,328	1,676,293,549	217,869,113	201,484,448	73,236,518	(8,692,300)	
26	AC:[]							
27	AD:[ADJUSTMENTS TO OPERATING INCOME]							
28	AE:[ADD: ALLOWANCE FOR FUNDS]	99,281,340	62,116,969	7,956,756	15,067,664	14,108,009	31,942	NC Schedule 8 - Other Adjustmer
29	AF:[]							
30	AG:[DEDUCT: CHARITABLE & EDUCATIONAL]							
31	AH:[DONATIONS]	7,637,022	6,374,831	775,263	89,297	397,631	0	NC Schedule 8 - Other Adjustmer
32	AI:[DONATIONS - ASSIGNED]	0	0	0	0	0	0	NC Schedule 8 - Other Adjustmer
33	AJ:[INTEREST EXPENSE - CUST. DEPOSITS]	1,133,926	1,102,908	0	0	31,017	0	NC Schedule 8 - Other Adjustmer
34	AK:[OTHER INTEREST EXPENSE]	4,911,689	3,855,830	492,787	350,452	212,619	0	NC Schedule 8 - Other Adjustmer
35	AL:[TOTAL DEDUCTIONS]	13,682,637	11,333,570	1,268,050	439,749	641,268	0	
36	AM:[]							
37	AN:[ADJUSTED NET ELEC. OPERATING INCOME]	2,245,790,031	1,727,076,949	224,557,819	216,112,363	86,703,259	(8,660,358)	
38	AO:[]							
39	AP:[RATE BASE]	33,422,101,668	24,916,415,131	3,197,185,158	2,468,873,395	1,594,851,513	1,244,776,472	NC Schedule 1 - Summary/Line 84
40	AQ:[]							
41	AR:[ROR EARNED ON RATE BASE (Including Ringfenced as applic	6.7195%	6.9315%	7.0236%	8.7535%	5.4364%	(0.6957%)	
42	AS:[]							
43	AV:[SYSTEM RATE OF RETURN (Excluding Ringfenced as applical	7.0063%	7.0063%	7.0063%	7.0063%	7.0063%	(0.6957%)	
44	AW:[INDEX RATE OF RETURN (PRESENT) (AQ/AU)]	0.96	0.99	1.00	1.25	0.78	1.00	
45	AX:[]							

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023

SCHEDULE 1

SCHEDULE 1 - SUMMARY

Line #		System	Va Juris	Va Non-Juris	FERC	N C Juris	Ringfenced Projects	Allocation Basis
46	AY:[]							
47	AZ:[]							
48	BA:[RATE BASE]							
49	BB:[PLANT INVESTMENT]							
50	BC:[ELECTRIC PLANT INCL. NUCLEAR FUEL]	53,644,012,778	41,039,507,308	5,194,644,216	3,371,575,571	2,269,147,992	1,769,137,692	NC Schedule 10 - Plant in Service/
51	BD:[ACQUISITION ADJUSTMENTS]	52,041,189	33,361,610	16,387,208	1,979,312	313,057	0	NC Schedule 10 - Plant in Service/
52	BE:[ELECTRIC CWIP INCL FUEL]	8,022,232,796	6,484,052,306	829,448,327	343,129,369	360,345,332	5,257,462	NC Schedule 12 - Construction Wc
53	BF:[PLANT HELD FOR FUTURE USE]	0	0	0	0	0	0	NC Schedule 13 - Plant Held for Fu
54	BG:[TOTAL PLANT INVESTMENT]	61,718,286,763	47,556,921,224	6,040,479,751	3,716,684,253	2,629,806,381	1,774,395,154	
55	BH:[]							
56	BI:[DEDUCT:]							
57	BJ:[ACCUM. PROV. FOR DEPREC. & AMORT]	(17,303,912,667)	(13,913,115,395)	(1,709,785,150)	(735,483,458)	(778,067,179)	(167,461,484)	NC Schedule 11 - Accum Depr & A
58	BK:[AMORT OF NUCLEAR FUEL]	(1,283,254,069)	(1,052,845,968)	(153,283,603)	(21,429,907)	(55,694,591)	0	NC Schedule 11 - Accum Depr & A
59	BL:[ACQUISITION ADJ. FOR DEPREC. RESERVE]	(44,301,619)	(28,191,911)	(15,718,270)	(337,982)	(53,457)	0	NC Schedule 11 - Accum Depr & A
60	BM:[TOTAL DEPRECIATION & AMORTIZATION]	(18,631,468,355)	(14,994,153,274)	(1,878,787,023)	(757,251,347)	(833,815,226)	(167,461,484)	
61	BN:[]							
62	BO:[NET PLANT]	43,086,818,408	32,562,767,950	4,161,692,728	2,959,432,905	1,795,991,155	1,606,933,670	
63	BP:[]							
64	BQ:[DEDUCT:]							
65	BS:[ACCUMULATED DEFERRED INCOME TAXES]	4,112,057,237	2,980,183,142	367,982,293	267,537,706	185,445,996	310,908,100	NC Schedule 23 - Cost Free Capita
67	BW:[CUSTOMER DEPOSITS]	114,643,074	111,507,126	0	0	3,135,948	0	NC Schedule 14 - Working Capital,
68	BX:[EXCESS DEFERRED INCOME TAXES]	2,360,637,744	1,850,725,132	228,978,807	173,351,117	107,582,689	0	NC Schedule 23 - Cost Free Capita
69	BY:[]							
70	BZ:[ADD: WORKING CAPITAL]							
71	CA:[MATERIAL & SUPPLIES]	1,187,573,754	980,349,113	129,454,806	27,036,527	50,733,308	0	NC Schedule 14 - Working Capital,
73	CC:[INVESTOR FUNDS ADVANCED]	364,879,977	296,630,610	37,072,975	15,384,829	15,791,563		NC Schedule 14 - Working Capital,
74	CD:[TOTAL ADDITIONS]	842,687,012	509,076,896	55,851,435	13,218,563	264,540,117		NC Schedule 14 - Working Capital,
78	CH:[TOTAL DEDUCTIONS]	(5,472,519,427)	(4,489,994,038)	(589,925,687)	(105,310,607)	(236,039,996)	(51,249,098)	NC Schedule 14 - Working Capital,
80	CJ:[DEFERRED FUEL]	0	0	0	0	0	0	NC Schedule 14 - Working Capital,
82	CL:[TOTAL ALLOWANCE FOR WORK CAPITAL]	(3,077,378,684)	(2,703,937,419)	(367,546,470)	(49,670,688)	95,024,991	(51,249,098)	
83	CM:[]							
84	CN:[TOTAL RATE BASE]	33,422,101,668	24,916,415,131	3,197,185,158	2,468,873,395	1,594,851,513	1,244,776,472	
85	CO:[]							

Dominion Energy North Carolina
Docket No. E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023

SCHEDULE 1

SCHEDULE 1 - SUMMARY

Line #		NC Jur Total	Residential	SGS,CO & Muni	LGS	Schedule NS	6VP	St & Outdoor Lighting	Traffic Lighting	Allocation Basis
1	Dec 2023									
2										
3	C:[SUMMARY OF RESULTS]									
4	D:[]									
5	E:[OPERATING REVENUES]	408,196,365	195,316,809	82,954,197	53,573,616	47,867,823	22,179,446	6,235,339	69,136	NC Class Schedule 2 - Revenue/Li
6	F:[]									
7	G:[OPERATING EXPENSES]									
8	H:[OPERATION & MAINTENANCE EXPENSES]	239,139,128	103,862,367	48,265,423	32,366,092	36,674,676	14,387,971	3,539,256	43,343	NC Class Schedule 3 - O&M Exper
9	I:[DEPRECIATION EXPENSE]	60,832,913	32,938,221	11,999,020	6,081,591	4,868,688	2,645,332	2,288,208	11,853	NC Class Schedule 4 - Depreciatio
10	J:[AMORT. OF ACQ. AJUSTMENTS]	7,311	3,475	1,447	948	987	427	28	1	NC Class Schedule 4 - Depreciatio
11	K:[AMORT. OF PROP. LOSS & REG STUDY]	83,583	39,873	16,552	10,800	11,180	4,859	312	8	NC Class Schedule 6 - Net Current
12	L:[REGULATORY DEBITS AND CREDITS]	10,909,089	4,862,489	2,147,467	1,495,443	1,680,322	671,733	50,540	1,095	NC Class Schedule 6 - Net Current
13	N:[GAIN/LOSS ON DISPOSITION OF ALLOWANCES]	(89,091)	(35,475)	(17,379)	(13,278)	(16,464)	(5,951)	(534)	(10)	NC Class Schedule 6 - Net Current
14	O:[GAIN / LOSS ON DISPOSITION OF PROPERTY]	245,242	130,760	48,761	25,983	21,679	11,371	6,647	41	NC Class Schedule 6 - Net Current
15	Q:[ACCRETION EXPENSE - ARO]	5,133,919	2,110,371	1,004,219	748,906	906,661	335,844	27,314	605	NC Class Schedule 22 - Other Alloc
16	R:[FEDERAL INCOME TAX]									
17	S:[INVESTMENT TAX CREDIT - AMORTIZATION]	141,040	73,832	28,586	16,039	15,072	7,230	262	18	NC Class Schedule 7 - Income Tax
18	T:[FEDERAL NET CURRENT TAX]	6,833,874	3,508,679	1,581,690	1,534,858	109,979	362,475	(264,224)	416	NC Class Schedule 6 - Net Current
19	U:[FEDERAL INCOME TAX DEFERRED]	(3,208,237)	(949,924)	(618,181)	(586,129)	(777,403)	(254,728)	(21,538)	(334)	NC Class Schedule 7 - Income Tax
20	W:[STATE INCOME TAX CURRENT]	483,103	297,290	111,167	87,235	(20,063)	18,572	(11,146)	48	NC Class Schedule 6 - Net Current
21	X:[STATE INCOME TAX DEFERRED]	1,812,324	1,115,260	417,034	327,255	(75,265)	69,673	(41,812)	178	NC Class Schedule 7 - Income Tax
22	Y:[TAXES OTHER THAN INCOME TAX]	12,635,649	6,777,059	2,524,111	1,322,957	1,084,683	578,318	346,228	2,294	NC Class Schedule 5 - Other Taxes
23	Z:[TOTAL ELECTRIC OPERATING EXPENSES]	334,959,847	154,734,276	67,509,918	43,418,701	44,484,730	18,833,126	5,919,540	59,555	
24	AA:[]									
25	AB:[NET OPERATING INCOME]	73,236,518	40,582,533	15,444,279	10,154,915	3,383,093	3,346,320	315,798	9,580	
26	AC:[]									
27	AD:[ADJUSTMENTS TO OPERATING INCOME]									
28	AE:[ADD: ALLOWANCE FOR FUNDS]	14,108,009	6,785,499	2,794,670	1,797,229	1,838,863	806,876	83,438	1,435	NC Class Schedule 8 - Other Adjus
29	AF:[]									
30	AG:[DEDUCT: CHARITABLE & EDUCATIONAL]									
31	AH:[DONATIONS]	397,631	172,698	80,254	53,817	60,981	23,924	5,885	72	NC Class Schedule 8 - Other Adjus
32	AI:[DONATIONS - ASSIGNED]	0	0	0	0	0	0	0	0	NC Class Schedule 8 - Other Adjus
33	AJ:[INTEREST EXPENSE - CUST. DEPOSITS]	31,017	14,826	6,309	4,080	3,641	1,688	468	5	NC Class Schedule 8 - Other Adjus
34	AK:[OTHER INTEREST EXPENSE]	212,619	110,786	42,373	23,490	20,475	10,475	4,987	34	NC Class Schedule 8 - Other Adjus
35	AL:[TOTAL DEDUCTIONS]	641,268	298,310	128,935	81,387	85,098	36,086	11,340	111	
36	AM:[]									
37	AN:[ADJUSTED NET ELEC. OPERATING INCOME]	86,703,259	47,069,722	18,110,013	11,870,756	5,136,858	4,117,110	387,896	10,904	
38	AO:[]									
39	AP:[RATE BASE]	1,594,851,513	823,640,771	318,044,620	178,678,915	158,156,503	79,792,715	36,292,242	245,747	NC Class Schedule 1 - Summary/L
40	AQ:[]									
41	AR:[ROR EARNED ON RATE BASE (Including Ringfenced as applic	5.4364%	5.7148%	5.6942%	6.6436%	3.2480%	5.1598%	1.0688%	4.4370%	
42	AS:[]									
43	AV:[SYSTEM RATE OF RETURN (Excluding Ringfenced as applicat	5.4364%	5.4364%	5.4364%	5.4364%	5.4364%	5.4364%	5.4364%	5.4364%	
44	AW:[INDEX RATE OF RETURN (PRESENT) (AQ/AU)]	1.00	1.05	1.05	1.22	0.60	0.95	0.20	0.82	
45	AX:[]									

Dominion Energy North Carolina
Docket No. E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023

SCHEDULE 1

SCHEDULE 1 - SUMMARY

Line #		NC Jur Total	Residential	SGS,CO & Muni	LGS	Schedule NS	6VP	St & Outdoor Lighting	Traffic Lighting	Allocation Basis
46	AY:[]									
47	AZ:[]									
48	BA:[RATE BASE]									
49	BB:[PLANT INVESTMENT]									
50	BC:[ELECTRIC PLANT INCL. NUCLEAR FUEL]	2,269,147,992	1,209,882,124	451,169,675	240,414,137	200,586,888	105,216,371	61,503,206	375,591	NC Class Schedule 10 - Plant in Ser
51	BD:[ACQUISITION ADJUSTMENTS]	313,057	148,775	61,973	40,592	42,241	18,262	1,185	30	NC Class Schedule 10 - Plant in Ser
52	BE:[ELECTRIC CWIP INCL FUEL]	360,345,332	175,364,506	71,302,256	45,029,334	45,337,306	19,991,104	3,279,163	41,663	NC Class Schedule 12 - Constructio
53	BF:[PLANT HELD FOR FUTURE USE]	0	0	0	0	0	0	0	0	NC Class Schedule 13 - Plant Held
54	BG:[TOTAL PLANT INVESTMENT]	2,629,806,381	1,385,395,405	522,533,903	285,484,062	245,966,434	125,225,738	64,783,554	417,284	
55	BH:[]									
56	BI:[DEDUCT:]									
57	BJ:[ACCUM. PROV. FOR DEPREC. & AMORT]	(778,067,179)	(427,373,314)	(153,737,434)	(78,762,310)	(62,726,386)	(33,023,333)	(22,318,747)	(125,654)	NC Class Schedule 11 - Accum Dep
58	BK:[AMORT OF NUCLEAR FUEL]	(55,694,591)	(22,176,751)	(10,864,121)	(8,300,666)	(10,292,639)	(3,720,343)	(334,112)	(5,959)	NC Class Schedule 11 - Accum Dep
59	BL:[ACQUISITION ADJ. FOR DEPREC. RESERVE]	(53,457)	(25,404)	(10,582)	(6,931)	(7,213)	(3,118)	(202)	(5)	NC Class Schedule 11 - Accum Dep
60	BM:[TOTAL DEPRECIATION & AMORTIZATION]	(833,815,226)	(449,575,469)	(164,612,137)	(87,069,908)	(73,026,238)	(36,746,795)	(22,653,061)	(131,619)	
61	BN:[]									
62	BO:[NET PLANT]	1,795,991,155	935,819,936	357,921,766	198,414,154	172,940,197	88,478,943	42,130,493	285,666	
63	BP:[]									
64	BQ:[DEDUCT:]									
65	BS:[ACCUMULATED DEFERRED INCOME TAXES]	185,445,996	91,809,834	36,653,275	21,896,637	21,476,040	9,693,924	3,888,676	27,611	NC Class Schedule 23 - Cost Free C
67	BW:[CUSTOMER DEPOSITS]	3,135,948	1,498,955	637,850	412,511	368,147	170,631	47,328	525	NC Class Schedule 14 - Working Ca
68	BX:[EXCESS DEFERRED INCOME TAXES]	107,582,689	57,499,447	21,434,753	11,393,307	9,393,161	4,988,837	2,856,510	16,674	NC Class Schedule 23 - Cost Free C
69	BY:[]									
70	BZ:[ADD: WORKING CAPITAL]									
71	CA:[MATERIAL & SUPPLIES]	50,733,308	24,298,512	10,027,002	6,300,007	6,479,546	2,796,547	825,133	6,561	NC Class Schedule 14 - Working Ca
73	CC:[INVESTOR FUNDS ADVANCED]	15,791,563	7,557,533	3,209,401	2,072,265	1,850,372	857,760	241,556	2,677	NC Class Schedule 14 - Working Ca
74	CD:[TOTAL ADDITIONS]	264,540,117	111,267,157	51,809,718	37,761,586	44,878,664	16,913,602	1,880,281	29,108	NC Class Schedule 14 - Working Ca
78	CH:[TOTAL DEDUCTIONS]	(236,039,996)	(104,494,132)	(46,197,389)	(32,166,643)	(36,754,927)	(14,400,745)	(1,992,706)	(33,453)	NC Class Schedule 14 - Working Ca
80	CJ:[DEFERRED FUEL]	0	0	0	0	0	0	0	0	NC Class Schedule 14 - Working Ca
82	CL:[TOTAL ALLOWANCE FOR WORK CAPITAL]	95,024,991	38,629,071	18,848,732	13,967,215	16,453,654	6,167,164	954,263	4,892	
83	CM:[]									
84	CN:[TOTAL RATE BASE]	1,594,851,513	823,640,771	318,044,620	178,678,915	158,156,503	79,792,715	36,292,242	245,747	
85	CO:[]									

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**Residential Class** **Annualized Cost of Service Summary** DESCRIPTION	(1) Residential Cost of Service	(2) Annualized Revenue Adjustment	(3) Residential Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$129,458,157	$2,964,453	$132,422,610
2	Forfeited Discounts and Miscellaneous Service Revenues	$761,746	$27,665	$789,410
3	Non-Fuel Rider Revenues	$2,842,691	$0	$2,842,691
4	Fuel Revenues	$60,621,360	$0	$60,621,360
5	Other Operating Revenues	$1,632,855	$0	$1,632,855
6	TOTAL OPERATING REVENUES	$195,316,809	$2,992,117	$198,308,926
	OPERATING EXPENSES			
7	Fuel Expense	$61,522,679		$61,522,679
8	Non-Fuel Operating and Maintenance Expense	$42,339,688	$21,792	$42,361,480
9	Depreciation and Amortization	$39,954,428		$39,954,428
10	Federal Income Tax	$2,632,587	$586,943	$3,219,530
11	State Income Tax	$1,412,550	$170,977	$1,583,528
12	Taxes Other than Income Tax	$6,777,059	$4,381	$6,781,440
13	(Gain)/Loss on Disposition of Property	$95,285		$95,285
14	TOTAL ELECTRIC OPERATING EXPENSES	$154,734,276	$784,094	$155,518,370
15	**NET OPERATING INCOME**	$40,582,533	$2,208,024	$42,790,557
	ADJUSTMENTS TO OPERATING INCOME			
16	*ADD:* AFUDC	$6,785,499		$6,785,499
17	*LESS:* Charitable Donations	$172,698		$172,698
18	Interest Expense on Customer Deposits	$14,826		$14,826
19	Other Interest Expense/(Income)	$110,786		$110,786
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$47,069,722	$2,208,024	$49,277,746
21	**RATE BASE (from Line 38 below)**	$823,640,771	$0	$823,640,771
22	**ROR EARNED ON AVERAGE RATE BASE**	5.7148%		5.9829%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$24,298,512		$24,298,512
24	Investor Funds Advanced	$7,557,533		$7,557,533
25	Total Additions	$111,267,157		$111,267,157
26	Total Deductions	($104,494,132)		($104,494,132)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$38,629,071	$0	$38,629,071
	NET UTILITY PLANT			
28	Utility Plant in Service	$1,209,882,124		$1,209,882,124
29	Acquisition Adjustments	$148,775		$148,775
30	Construction Work in Progress	$175,364,506		$175,364,506
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$449,550,065		$449,550,065
32	Provision for Acquisition Adjustments	$25,404		$25,404
33	TOTAL NET UTILITY PLANT	$935,819,936	$0	$935,819,936
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$1,498,955		$1,498,955
35	Accumulated Deferred Income Taxes	$91,809,834		$91,809,834
36	Other Cost Free Capital	$57,499,447		$57,499,447
37	TOTAL RATE BASE DEDUCTIONS	$150,808,236	$0	$150,808,236
38	**TOTAL RATE BASE**	$823,640,771	$0	$823,640,771

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**SGS & Public Authorities Class** **Annualized Cost of Service Summary** DESCRIPTION	(1) SGS Cost of Service	(2) Annualized Revenue Adjustment	(3) SGS Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$51,071,053	($989,408)	$50,081,644
2	Forfeited Discounts and Miscellaneous Service Revenues	$210,233	$9,925	$220,158
3	Non-Fuel Rider Revenues	$1,325,418	$0	
4	Fuel Revenues	$29,697,669	$0	$29,697,669
5	Other Operating Revenues	$649,825	$0	$649,825
6	TOTAL OPERATING REVENUES	$82,954,197	($979,483)	$81,974,713
	OPERATING EXPENSES			
7	Fuel Expense	$30,139,214		$30,139,214
8	Non-Fuel Operating and Maintenance Expense	$18,126,209	($7,134)	$18,119,075
9	Depreciation and Amortization	$15,168,705		$15,168,705
10	Federal Income Tax	$992,096	($192,139)	$799,957
11	State Income Tax	$528,201	($55,970)	$472,231
12	Taxes Other than Income Tax	$2,524,111	($1,434)	$2,522,677
13	(Gain)/Loss on Disposition of Property	$31,382		$31,382
14	TOTAL ELECTRIC OPERATING EXPENSES	$67,509,918	($256,677)	$67,253,242
15	**NET OPERATING INCOME**	$15,444,279	($722,807)	$14,721,472
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$2,794,670		$2,794,670
17	LESS: Charitable Donations	$80,254		$80,254
18	Interest Expense on Customer Deposits	$6,309		$6,309
19	Other Interest Expense/(Income)	$42,373		$42,373
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$18,110,013	($722,807)	$17,387,206
21	**RATE BASE (from Line 38 below)**	$318,044,620	$0	$318,044,620
22	**ROR EARNED ON AVERAGE RATE BASE**	5.6942%		5.4669%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$10,027,002		$10,027,002
24	Investor Funds Advanced	$3,209,401		$3,209,401
25	Total Additions	$51,809,718		$51,809,718
26	Total Deductions	($46,197,389)		($46,197,389)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$18,848,732	$0	$18,848,732
	NET UTILITY PLANT			
28	Utility Plant in Service	$451,169,675		$451,169,675
29	Acquisition Adjustments	$61,973		$61,973
30	Construction Work in Progress	$71,302,256		$71,302,256
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$164,601,555		$164,601,555
32	Provision for Acquisition Adjustments	$10,582		$10,582
33	TOTAL NET UTILITY PLANT	$357,921,766	$0	$357,921,766
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$637,850		$637,850
35	Accumulated Deferred Income Taxes	$36,653,275		$36,653,275
36	Other Cost Free Capital	$21,434,753		$21,434,753
37	TOTAL RATE BASE DEDUCTIONS	$58,725,879	$0	$58,725,879
38	**TOTAL RATE BASE**	$318,044,620	$0	$318,044,620

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LGS Class
Annualized Cost of Service Summary

LINE NO.	DESCRIPTION	(1) LGS Cost of Service	(2) Annualized Revenue Adjustment	(3) LGS Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$29,965,627	($3,799,029)	$26,166,598
2	Forfeited Discounts and Miscellaneous Service Revenues	$88,823	$5,654	$94,477
3	Non-Fuel Rider Revenues	$436,077	$0	
4	Fuel Revenues	$22,690,325	$0	$22,690,325
5	Other Operating Revenues	$392,765	$0	$392,765
6	TOTAL OPERATING REVENUES	$53,573,616	($3,793,375)	$49,780,241
	OPERATING EXPENSES			
7	Fuel Expense	$23,027,685		$23,027,685
8	Non-Fuel Operating and Maintenance Expense	$9,338,408	($27,628)	$9,310,780
9	Depreciation and Amortization	$8,337,688		$8,337,688
10	Federal Income Tax	$964,769	($744,120)	$220,649
11	State Income Tax	$414,490	($216,763)	$197,727
12	Taxes Other than Income Tax	$1,322,957	($5,554)	$1,317,402
13	(Gain)/Loss on Disposition of Property	$12,705		$12,705
14	TOTAL ELECTRIC OPERATING EXPENSES	$43,418,701	($994,066)	$42,424,636
15	**NET OPERATING INCOME**	$10,154,915	($2,799,310)	$7,355,605
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$1,797,229		$1,797,229
17	LESS: Charitable Donations	$53,817		$53,817
18	Interest Expense on Customer Deposits	$4,080		$4,080
19	Other Interest Expense/(Income)	$23,490		$23,490
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$11,870,756	($2,799,310)	$9,071,447
21	**RATE BASE (from Line 38 below)**	$178,678,915	$0	$178,678,915
22	**ROR EARNED ON AVERAGE RATE BASE**	6.6436%		5.0770%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$6,300,007		$6,300,007
24	Investor Funds Advanced	$2,072,265		$2,072,265
25	Total Additions	$37,761,586		$37,761,586
26	Total Deductions	($32,166,643)		($32,166,643)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$13,967,215	$0	$13,967,215
	NET UTILITY PLANT			
28	Utility Plant in Service	$240,414,137		$240,414,137
29	Acquisition Adjustments	$40,592		$40,592
30	Construction Work in Progress	$45,029,334		$45,029,334
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$87,062,976		$87,062,976
32	Provision for Acquisition Adjustments	$6,931		$6,931
33	TOTAL NET UTILITY PLANT	$198,414,154	$0	$198,414,154
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$412,511		$412,511
35	Accumulated Deferred Income Taxes	$21,896,637		$21,896,637
36	Other Cost Free Capital	$11,393,307		$11,393,307
37	TOTAL RATE BASE DEDUCTIONS	$33,702,455	$0	$33,702,455
38	**TOTAL RATE BASE**	$178,678,915	$0	$178,678,915

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	DESCRIPTION **Schedule NS Class** **Annualized Cost of Service Summary**	(1) Sched NS Cost of Service	(2) Annualized Revenue Adjustment	(3) Sched NS Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$19,246,707	$563,784	$19,810,491
2	Forfeited Discounts and Miscellaneous Service Revenues	$79,098	$5,043	$84,142
3	Non-Fuel Rider Revenues	$0	$0	
4	Fuel Revenues	$28,135,491	$0	$28,135,491
5	Other Operating Revenues	$406,526	$0	$406,526
6	TOTAL OPERATING REVENUES	$47,867,823	$568,827	$48,436,650
	OPERATING EXPENSES			
7	Fuel Expense	$28,553,810		$28,553,810
8	Non-Fuel Operating and Maintenance Expense	$8,120,867	$4,143	$8,125,009
9	Depreciation and Amortization	$7,467,837		$7,467,837
10	Federal Income Tax	($652,351)	$111,583	($540,768)
11	State Income Tax	($95,328)	$32,504	($62,824)
12	Taxes Other than Income Tax	$1,084,683	$833	$1,085,516
13	(Gain)/Loss on Disposition of Property	$5,214		$5,214
14	TOTAL ELECTRIC OPERATING EXPENSES	$44,484,730	$149,063	$44,633,793
15	**NET OPERATING INCOME**	$3,383,093	$419,764	$3,802,857
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$1,838,863		$1,838,863
17	LESS: Charitable Donations	$60,981		$60,981
18	Interest Expense on Customer Deposits	$3,641		$3,641
19	Other Interest Expense/(Income)	$20,475		$20,475
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$5,136,858	$419,764	$5,556,622
21	**RATE BASE (from Line 38 below)**	$158,156,503	$0	$158,156,503
22	**ROR EARNED ON AVERAGE RATE BASE**	3.2480%		3.5134%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$6,479,546		$6,479,546
24	Investor Funds Advanced	$1,850,372		$1,850,372
25	Total Additions	$44,878,664		$44,878,664
26	Total Deductions	($36,754,927)		($36,754,927)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$16,453,654	$0	$16,453,654
	NET UTILITY PLANT			
28	Utility Plant in Service	$200,586,888		$200,586,888
29	Acquisition Adjustments	$42,241		$42,241
30	Construction Work in Progress	$45,337,306		$45,337,306
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$73,019,025		$73,019,025
32	Provision for Acquisition Adjustments	$7,213		$7,213
33	TOTAL NET UTILITY PLANT	$172,940,197	$0	$172,940,197
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$368,147		$368,147
35	Accumulated Deferred Income Taxes	$21,476,040		$21,476,040
36	Other Cost Free Capital	$9,393,161		$9,393,161
37	TOTAL RATE BASE DEDUCTIONS	$31,237,348	$0	$31,237,348
38	**TOTAL RATE BASE**	$158,156,503	$0	$158,156,503

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**6VP Class** **Annualized Cost of Service Summary** DESCRIPTION	(1) 6VP Cost of Service	(2) Annualized Revenue Adjustment	(3) 6VP Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$11,790,962	($1,986,650)	$9,804,313
2	Forfeited Discounts and Miscellaneous Service Revenues	$36,671	$2,338	$39,009
3	Non-Fuel Rider Revenues	$223	$0	
4	Fuel Revenues	$10,169,761	$0	$10,169,761
5	Other Operating Revenues	$181,829	$0	$181,829
6	TOTAL OPERATING REVENUES	$22,179,446	($1,984,312)	$20,195,134
	OPERATING EXPENSES			
7	Fuel Expense	$10,320,965		$10,320,965
8	Non-Fuel Operating and Maintenance Expense	$4,067,006	($14,452)	$4,052,553
9	Depreciation and Amortization	$3,658,194		$3,658,194
10	Federal Income Tax	$114,977	($389,249)	($274,271)
11	State Income Tax	$88,245	($113,389)	($25,143)
12	Taxes Other than Income Tax	$578,318	($2,906)	$575,412
13	(Gain)/Loss on Disposition of Property	$5,420		$5,420
14	TOTAL ELECTRIC OPERATING EXPENSES	$18,833,126	($519,995)	$18,313,131
15	**NET OPERATING INCOME**	$3,346,320	($1,464,317)	$1,882,003
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$806,876		$806,876
17	LESS: Charitable Donations	$23,924		$23,924
18	Interest Expense on Customer Deposits	$1,688		$1,688
19	Other Interest Expense/(Income)	$10,475		$10,475
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$4,117,110	($1,464,317)	$2,652,793
21	**RATE BASE (from Line 38 below)**	$79,792,715	$0	$79,792,715
22	**ROR EARNED ON AVERAGE RATE BASE**	5.1598%		3.3246%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$2,796,547		$2,796,547
24	Investor Funds Advanced	$857,760		$857,760
25	Total Additions	$16,913,602		$16,913,602
26	Total Deductions	($14,400,745)		($14,400,745)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$6,167,164	$0	$6,167,164
	NET UTILITY PLANT			
28	Utility Plant in Service	$105,216,371		$105,216,371
29	Acquisition Adjustments	$18,262		$18,262
30	Construction Work in Progress	$19,991,104		$19,991,104
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$36,743,676		$36,743,676
32	Provision for Acquisition Adjustments	$3,118		$3,118
33	TOTAL NET UTILITY PLANT	$88,478,943	$0	$88,478,943
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$170,631		$170,631
35	Accumulated Deferred Income Taxes	$9,693,924		$9,693,924
36	Other Cost Free Capital	$4,988,837		$4,988,837
37	TOTAL RATE BASE DEDUCTIONS	$14,853,391	$0	$14,853,391
38	**TOTAL RATE BASE**	$79,792,715	$0	$79,792,715

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

Street and Outdoor Lighting Class
Annualized Cost of Service Summary

LINE NO.	DESCRIPTION	(1) Street & Outdoor Lighting Cost of Service	(2) Annualized Revenue Adjustment	(3) Street & Outdoor Lighting COS Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$5,178,064	($21,493)	$5,156,571
2	Forfeited Discounts and Miscellaneous Service Revenues	$76,019	$1,716	$77,735
3	Non-Fuel Rider Revenues	$0	$0	
4	Fuel Revenues	$913,313	$0	$913,313
5	Other Operating Revenues	$67,943	$0	$67,943
6	TOTAL OPERATING REVENUES	$6,235,339	($19,776)	$6,215,562
	OPERATING EXPENSES			
7	Fuel Expense	$926,892		$926,892
8	Non-Fuel Operating and Maintenance Expense	$2,612,364	($144)	$2,612,220
9	Depreciation and Amortization	$2,366,402		$2,366,402
10	Federal Income Tax	($285,500)	($3,879)	($289,379)
11	State Income Tax	($52,958)	($1,130)	($54,088)
12	Taxes Other than Income Tax	$346,228	($29)	$346,199
13	(Gain)/Loss on Disposition of Property	$6,113		$6,113
14	TOTAL ELECTRIC OPERATING EXPENSES	$5,919,540	($5,182)	$5,914,358
15	**NET OPERATING INCOME**	$315,798	($14,594)	$301,204
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$83,438		$83,438
17	LESS: Charitable Donations	$5,885		$5,885
18	Interest Expense on Customer Deposits	$468		$468
19	Other Interest Expense/(Income)	$4,987		$4,987
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$387,896	($14,594)	$373,302
21	**RATE BASE (from Line 38 below)**	$36,292,242	$0	$36,292,242
22	**ROR EARNED ON AVERAGE RATE BASE**	1.0688%		1.0286%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$825,133		$825,133
24	Investor Funds Advanced	$241,556		$241,556
25	Total Additions	$1,880,281		$1,880,281
26	Total Deductions	($1,992,706)		($1,992,706)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$954,263	$0	$954,263
	NET UTILITY PLANT			
28	Utility Plant in Service	$61,503,206		$61,503,206
29	Acquisition Adjustments	$1,185		$1,185
30	Construction Work in Progress	$3,279,163		$3,279,163
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$22,652,859		$22,652,859
32	Provision for Acquisition Adjustments	$202		$202
33	TOTAL NET UTILITY PLANT	$42,130,493	$0	$42,130,493
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$47,328		$47,328
35	Accumulated Deferred Income Taxes	$3,888,676		$3,888,676
36	Other Cost Free Capital	$2,856,510		$2,856,510
37	TOTAL RATE BASE DEDUCTIONS	$6,792,515	$0	$6,792,515
38	**TOTAL RATE BASE**	$36,292,242	$0	$36,292,242

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**Traffic Lighting Class** **Annualized Cost of Service Summary** DESCRIPTION	(1) Traffic Lighting Cost of Service	(2) Annualized Revenue Adjustment	(3) Traffic Lighting Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$51,314	($3,115)	$48,199
2	Forfeited Discounts and Miscellaneous Service Revenues	$899	$20	$919
3	Non-Fuel Rider Revenues	$0	$0	
4	Fuel Revenues	$16,290	$0	$16,290
5	Other Operating Revenues	$633	$0	$633
6	TOTAL OPERATING REVENUES	$69,136	($3,095)	$66,041
	OPERATING EXPENSES			
7	Fuel Expense	$16,532		$16,532
8	Non-Fuel Operating and Maintenance Expense	$26,811	($23)	$26,788
9	Depreciation and Amortization	$13,562		$13,562
10	Federal Income Tax	$100	($607)	($507)
11	State Income Tax	$226	($177)	$49
12	Taxes Other than Income Tax	$2,294	($5)	$2,290
13	(Gain)/Loss on Disposition of Property	$31		$31
14	TOTAL ELECTRIC OPERATING EXPENSES	$59,555	($811)	$58,744
15	**NET OPERATING INCOME**	$9,580	($2,284)	$7,297
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$1,435		$1,435
17	LESS: Charitable Donations	$72		$72
18	Interest Expense on Customer Deposits	$5		$5
19	Other Interest Expense/(Income)	$34		$34
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$10,904	($2,284)	$8,620
21	**RATE BASE (from Line 38 below)**	$245,747	$0	$245,747
22	**ROR EARNED ON AVERAGE RATE BASE**	4.4370%		3.5077%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$6,561		$6,561
24	Investor Funds Advanced	$2,677		$2,677
25	Total Additions	$29,108		$29,108
26	Total Deductions	($33,453)		($33,453)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$4,892	$0	$4,892
	NET UTILITY PLANT			
28	Utility Plant in Service	$375,591		$375,591
29	Acquisition Adjustments	$30		$30
30	Construction Work in Progress	$41,663		$41,663
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$131,613		$131,613
32	Provision for Acquisition Adjustments	$5		$5
33	TOTAL NET UTILITY PLANT	$285,666	$0	$285,666
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$525		$525
35	Accumulated Deferred Income Taxes	$27,611		$27,611
36	Other Cost Free Capital	$16,674		$16,674
37	TOTAL RATE BASE DEDUCTIONS	$44,810	$0	$44,810
38	**TOTAL RATE BASE**	$245,747	$0	$245,747

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**Total of All North Carolina Classes** **Annualized Cost of Service Summary** DESCRIPTION	(1) Total Cost of Service	(2) Annualized Revenue Adjustment	(3) Total Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$246,761,884	($3,271,458)	$243,490,426
2	Forfeited Discounts and Miscellaneous Service Revenues	$1,253,489	$52,361	$1,305,850
3	Non-Fuel Rider Revenues	$4,604,409	$0	$4,604,409
4	Fuel Revenues	$152,244,208	$0	$152,244,208
5	Other Operating Revenues	$3,332,375	$0	$3,332,375
6	TOTAL OPERATING REVENUES	$408,196,365	($3,219,098)	$404,977,268
	OPERATING EXPENSES			
7	Fuel Expense	$154,507,777	$0	$154,507,777
8	Non-Fuel Operating and Maintenance Expense	$84,631,351	($23,445)	$84,607,906
9	Depreciation and Amortization	$76,966,815	$0	$76,966,815
10	Federal Income Tax	$3,766,678	($631,468)	$3,135,210
11	State Income Tax	$2,295,427	($183,947)	$2,111,479
12	Taxes Other than Income Tax	$12,635,649	($4,714)	$12,630,935
13	(Gain)/Loss on Disposition of Property	$156,151	$0	$156,151
14	TOTAL ELECTRIC OPERATING EXPENSES	$334,959,847	($843,574)	$334,116,273
15	**NET OPERATING INCOME**	$73,236,518	($2,375,523)	$70,860,995
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$14,108,009	$0	$14,108,009
17	LESS: Charitable Donations	$397,631	$0	$397,631
18	Interest Expense on Customer Deposits	$31,017	$0	$31,017
19	Other Interest Expense/(Income)	$212,619	$0	$212,619
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$86,703,259	($2,375,523)	$84,327,736
21	**RATE BASE (from Line 38 below)**	$1,594,851,513	$0	$1,594,851,513
22	**ROR EARNED ON AVERAGE RATE BASE**	5.4364%		5.2875%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$50,733,308	$0	$50,733,308
24	Investor Funds Advanced	$15,791,563	$0	$15,791,563
25	Total Additions	$264,540,117	$0	$264,540,117
26	Total Deductions	($236,039,996)	$0	($236,039,996)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$95,024,991	$0	$95,024,991
	NET UTILITY PLANT			
28	Utility Plant in Service	$2,269,147,992	$0	$2,269,147,992
29	Acquisition Adjustments	$313,057	$0	$313,057
30	Construction Work in Progress	$360,345,332	$0	$360,345,332
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$833,761,769	$0	$833,761,769
32	Provision for Acquisition Adjustments	$53,457	$0	$53,457
33	TOTAL NET UTILITY PLANT	$1,795,991,155	$0	$1,795,991,155
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$3,135,948	$0	$3,135,948
35	Accumulated Deferred Income Taxes	$185,445,996	$0	$185,445,996
36	Other Cost Free Capital	$107,582,689	$0	$107,582,689
37	TOTAL RATE BASE DEDUCTIONS	$296,164,633	$0	$296,164,633
38	**TOTAL RATE BASE**	$1,594,851,513	$0	$1,594,851,513

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Residential Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **Residential Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **Residential Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **Residential Base Non-Fuel Additional Revenue Requirement**	**(5)** **Residential Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$129,458,157	$11,065,338	$140,523,495	$30,041,017	$170,564,512
2	Forfeited Discounts and Misc. Service Revenues	$761,746	$27,665	$789,410	($164,523)	$624,888
3	Non-Fuel Rider Revenues	$2,842,691	($2,842,691)	$0		$0
4	Fuel Revenues	$60,621,360	($6,088,841)	$54,532,519		$54,532,519
5	Other Operating Revenues	$1,632,855	($1,802)	$1,631,053		$1,631,053
6	TOTAL OPERATING REVENUES	$195,316,809	$2,159,669	$197,476,478	$29,876,494	$227,352,972
	OPERATING EXPENSES					
7	Fuel Expense	$61,522,679	($7,070,595)	$54,452,084		$54,452,084
8	Non-Fuel Operating and Maintenance Expense	$42,339,688	$8,897,199	$51,236,887	$261,343	$51,498,229
9	Depreciation and Amortization	$39,954,428	$265,935	$40,220,363		$40,220,363
10	Federal Income Tax	$2,632,587	$855,152	$3,487,739	$5,860,666	$9,348,405
11	State Income Tax	$1,412,550	$248,691	$1,661,242	$1,707,219	$3,368,461
12	Taxes Other than Income Tax	$6,777,059	$269,575	$7,046,634		$7,046,634
13	(Gain)/Loss on Disposition of Property	$95,285	($130,760)	($35,475)		($35,475)
14	TOTAL ELECTRIC OPERATING EXPENSES	$154,734,276	$3,335,197	$158,069,474	$7,829,227	$165,898,701
15	**NET OPERATING INCOME**	$40,582,533	($1,175,529)	$39,407,004	$22,047,267	$61,454,271
	ADJUSTMENTS TO OPERATING INCOME					
16	*ADD:* AFUDC	$6,785,499	($6,785,499)	$0		$0
17	*LESS:* Charitable Donations	$172,698	($172,698)	$0		$0
18	Interest Expense on Customer Deposits	$14,826		$14,826		$14,826
19	Other Interest Expense/(Income)	$110,786		$110,786		$110,786
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$47,069,722	($7,788,330)	$39,281,392	$22,047,267	$61,328,659
21	**RATE BASE (from Line 38 below)**	$823,640,771	($127,418,637)	$696,222,134	$10,546,479	$706,768,613
22	**ROR EARNED ON AVERAGE RATE BASE**	5.7148%		5.6421%		8.6773%

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Residential Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Rate Base** DESCRIPTION	**(1)** **Residential Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **Residential Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **Residential Base Non-Fuel Additional Revenue Requirement**	**(5)** **Residential Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$24,298,512	$0	$24,298,512		$24,298,512
24	Investor Funds Advanced	$7,557,533	$11,749,020	$19,306,553	$10,546,479	$29,853,032
25	Total Additions	$111,267,157	($87,064,568)	$24,202,589		$24,202,589
26	Total Deductions	($104,494,132)	$85,865,342	($18,628,790)		($18,628,790)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$38,629,071	$10,549,794	$49,178,864	$10,546,479	$59,725,343
	NET UTILITY PLANT					
28	Utility Plant in Service	$1,209,882,124	$47,767,091	$1,257,649,215		$1,257,649,215
29	Acquisition Adjustments	$148,775	($148,775)	$0		$0
30	Construction Work in Progress	$175,364,506	($175,364,506)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$449,550,065	$20,987,916	$470,537,981		$470,537,981
32	Provision for Acquisition Adjustments	$25,404	($25,404)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$935,819,936	($148,708,701)	$787,111,235	$0	$787,111,235
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$1,498,955		$1,498,955		$1,498,955
35	Accumulated Deferred Income Taxes	$91,809,834	($9,802,849)	$82,006,984		$82,006,984
36	Other Cost Free Capital	$57,499,447	($937,421)	$56,562,026		$56,562,026
37	TOTAL RATE BASE DEDUCTIONS	$150,808,236	($10,740,271)	$140,067,965	$0	$140,067,965
38	**TOTAL RATE BASE**	$823,640,771	($127,418,637)	$696,222,134	$10,546,479	$706,768,613

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Small General Service, County, & Muni Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **SGS Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **SGS Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **SGS Base Non-Fuel Additional Revenue Requirement**	**(5)** **SGS Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	<u>OPERATING REVENUES</u>					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$51,071,053	$8,414	$51,079,467	$12,811,696	$63,891,163
2	Forfeited Discounts and Misc. Service Revenues	$210,233	$9,925	$220,158	($24,952)	$195,206
3	Non-Fuel Rider Revenues	$1,325,418	($1,325,418)	$0		$0
4	Fuel Revenues	$29,697,669	($2,982,849)	$26,714,819		$26,714,819
5	Other Operating Revenues	$649,825	($3,696)	$646,129		$646,129
6	<u>TOTAL OPERATING REVENUES</u>	$82,954,197	($4,293,624)	$78,660,573	$12,786,745	$91,447,317
	<u>OPERATING EXPENSES</u>					
7	Fuel Expense	$30,139,214	($3,463,799)	$26,675,415		$26,675,415
8	Non-Fuel Operating and Maintenance Expense	$18,126,209	$2,115,643	$20,241,852	$111,851	$20,353,703
9	Depreciation and Amortization	$15,168,705	($6,632)	$15,162,073		$15,162,073
10	Federal Income Tax	$992,096	($255,067)	$737,029	$2,508,288	$3,245,316
11	State Income Tax	$528,201	($74,474)	$453,727	$730,667	$1,184,394
12	Taxes Other than Income Tax	$2,524,111	$101,553	$2,625,665		$2,625,665
13	(Gain)/Loss on Disposition of Property	$31,382	($48,761)	($17,379)		($17,379)
14	<u>TOTAL ELECTRIC OPERATING EXPENSES</u>	$67,509,918	($1,631,536)	$65,878,382	$3,350,806	$69,229,188
15	**<u>NET OPERATING INCOME</u>**	$15,444,279	($2,662,088)	$12,782,191	$9,435,939	$22,218,130
	<u>ADJUSTMENTS TO OPERATING INCOME</u>					
16	ADD: AFUDC	$2,794,670	($2,794,670)	$0		$0
17	LESS: Charitable Donations	$80,254	($80,254)	$0		$0
18	Interest Expense on Customer Deposits	$6,309		$6,309		$6,309
19	Other Interest Expense/(Income)	$42,373		$42,373		$42,373
20	**<u>ADJUSTED NET ELECTRIC OPERATING INCOME</u>**	$18,110,013	($5,376,504)	$12,733,509	$9,435,939	$22,169,448
21	**<u>RATE BASE (from Line 38 below)</u>**	$318,044,620	($52,157,399)	$265,887,221	$4,662,581	$270,549,802
22	**<u>ROR EARNED ON AVERAGE RATE BASE</u>**	5.6942%		4.7891%		8.1942%

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Small General Service, County, & Muni Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Rate Base** DESCRIPTION	**(1)** **SGS Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **SGS Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **SGS Base Non-Fuel Additional Revenue Requirement**	**(5)** **SGS Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$10,027,002	$0	$10,027,002		$10,027,002
24	Investor Funds Advanced	$3,209,401	$4,989,998	$8,199,399	$4,662,581	$12,861,980
25	Total Additions	$51,809,718	($41,504,977)	$10,304,741		$10,304,741
26	Total Deductions	($46,197,389)	$39,408,142	($6,789,247)		($6,789,247)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$18,848,732	$2,893,164	$21,741,895	$4,662,581	$26,404,476
	NET UTILITY PLANT					
28	Utility Plant in Service	$451,169,675	$17,901,050	$469,070,725		$469,070,725
29	Acquisition Adjustments	$61,973	($61,972)	$0		$0
30	Construction Work in Progress	$71,302,256	($71,302,256)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$164,601,555	$7,684,553	$172,286,108		$172,286,108
32	Provision for Acquisition Adjustments	$10,582	($10,582)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$357,921,766	($61,137,149)	$296,784,617	$0	$296,784,617
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$637,850		$637,850		$637,850
35	Accumulated Deferred Income Taxes	$36,653,275	($5,738,184)	$30,915,092		$30,915,092
36	Other Cost Free Capital	$21,434,753	($348,403)	$21,086,350		$21,086,350
37	TOTAL RATE BASE DEDUCTIONS	$58,725,879	($6,086,586)	$52,639,292	$0	$52,639,292
38	**TOTAL RATE BASE**	$318,044,620	($52,157,399)	$265,887,221	$4,662,581	$270,549,802

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Large General Service Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **LGS Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **LGS Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **LGS Base Non-Fuel Additional Revenue Requirement**	**(5)** **LGS Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
	Base Non-Fuel Rate Revenues, Including Facilities Charges &					
1	Load Management	$29,965,627	($4,340,562)	$25,625,066	$5,469,633	$31,094,698
2	Forfeited Discounts and Misc. Service Revenues	$88,823	$5,654	$94,477	($14,337)	$80,140
3	Non-Fuel Rider Revenues	$436,077	($436,077)	$0		$0
4	Fuel Revenues	$22,690,325	($2,279,028)	$20,411,297		$20,411,297
5	Other Operating Revenues	$392,765	($4,567)	$388,198		$388,198
6	TOTAL OPERATING REVENUES	$53,573,616	($7,054,579)	$46,519,037	$5,455,296	$51,974,333
	OPERATING EXPENSES					
7	Fuel Expense	$23,027,685	($2,646,495)	$20,381,190		$20,381,190
8	Non-Fuel Operating and Maintenance Expense	$9,338,408	$2,065,976	$11,404,383	$47,720	$11,452,103
9	Depreciation and Amortization	$8,337,688	($123,914)	$8,213,774		$8,213,774
10	Federal Income Tax	$964,769	($1,071,425)	($106,655)	$1,070,128	$963,472
11	State Income Tax	$414,490	($312,221)	$102,270	$311,729	$413,999
12	Taxes Other than Income Tax	$1,322,957	$54,551	$1,377,507		$1,377,507
13	(Gain)/Loss on Disposition of Property	$12,705	($25,983)	($13,278)		($13,278)
14	TOTAL ELECTRIC OPERATING EXPENSES	$43,418,701	($2,059,510)	$41,359,191	$1,429,577	$42,788,768
15	**NET OPERATING INCOME**	$10,154,915	($4,995,069)	$5,159,846	$4,025,719	$9,185,565
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$1,797,229	($1,797,229)	$0		$0
17	LESS: Charitable Donations	$53,817	($53,817)	$0		$0
18	Interest Expense on Customer Deposits	$4,080		$4,080		$4,080
19	Other Interest Expense/(Income)	$23,490		$23,490		$23,490
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$11,870,756	($6,738,480)	$5,132,276	$4,025,719	$9,157,995
21	**RATE BASE (from Line 38 below)**	$178,678,915	($33,620,820)	$145,058,094	$3,135,654	$148,193,748
22	**ROR EARNED ON AVERAGE RATE BASE**	6.6436%		3.5381%		6.1797%

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

Large General Service Class
Fully Adjusted Cost of Service and Revenue Requirement
Rate Base

LINE NO.	DESCRIPTION	(1) LGS Cost of Service	(2) Ratemaking Adjustments	(3) LGS Fully Adjusted Cost of Service	(4) LGS Base Non-Fuel Additional Revenue Requirement	(5) LGS Fully Adjusted COS After Added Non-Fuel Base Revenues
				(Col 1 + Col 2)		(Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$6,300,007	$0	$6,300,007		$6,300,007
24	Investor Funds Advanced	$2,072,265	$3,222,649	$5,294,914	$3,135,654	$8,430,568
25	Total Additions	$37,761,586	($30,995,269)	$6,766,316		$6,766,316
26	Total Deductions	($32,166,643)	$28,427,147	($3,739,496)		($3,739,496)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$13,967,215	$654,527	$14,621,741	$3,135,654	$17,757,395
	NET UTILITY PLANT					
28	Utility Plant in Service	$240,414,137	$9,644,114	$250,058,251		$250,058,251
29	Acquisition Adjustments	$40,592	($40,592)	$0		$0
30	Construction Work in Progress	$45,029,334	($45,029,334)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$87,062,976	$4,052,937	$91,115,913		$91,115,913
32	Provision for Acquisition Adjustments	$6,931	($6,931)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$198,414,154	($39,471,817)	$158,942,337	$0	$158,942,337
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$412,511		$412,511		$412,511
35	Accumulated Deferred Income Taxes	$21,896,637	($5,012,513)	$16,884,124		$16,884,124
36	Other Cost Free Capital	$11,393,307	($183,958)	$11,209,349		$11,209,349
37	TOTAL RATE BASE DEDUCTIONS	$33,702,455	($5,196,470)	$28,505,985	$0	$28,505,985
38	**TOTAL RATE BASE**	$178,678,915	($33,620,820)	$145,058,094	$3,135,654	$148,193,748

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Schedule NS Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **Schedule NS Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **Schedule NS Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **Schedule NS Base Non-Fuel Additional Revenue Requirement**	**(5)** **Schedule NS Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$19,246,707	$2,781,188	$22,027,895	$4,460,850	$26,488,745
2	Forfeited Discounts and Misc. Service Revenues	$79,098	$5,043	$84,142	($14,866)	$69,275
3	Non-Fuel Rider Revenues	$0	$0	$0		$0
4	Fuel Revenues	$28,135,491	($2,825,943)	$25,309,548		$25,309,548
5	Other Operating Revenues	$406,526	($7,749)	$398,777		$398,777
6	TOTAL OPERATING REVENUES	$47,867,823	($47,462)	$47,820,361	$4,445,983	$52,266,344
	OPERATING EXPENSES					
7	Fuel Expense	$28,553,810	($3,281,594)	$25,272,216		$25,272,216
8	Non-Fuel Operating and Maintenance Expense	$8,120,867	$2,933,342	$11,054,208	$38,891	$11,093,099
9	Depreciation and Amortization	$7,467,837	($235,411)	$7,232,425		$7,232,425
10	Federal Income Tax	($652,351)	$268,139	($384,212)	$872,138	$487,926
11	State Income Tax	($95,328)	$77,991	($17,337)	$254,055	$236,718
12	Taxes Other than Income Tax	$1,084,683	$46,993	$1,131,676		$1,131,676
13	(Gain)/Loss on Disposition of Property	$5,214	($21,679)	($16,464)		($16,464)
14	TOTAL ELECTRIC OPERATING EXPENSES	$44,484,730	($212,218)	$44,272,512	$1,165,084	$45,437,596
15	**NET OPERATING INCOME**	$3,383,093	$164,756	$3,547,849	$3,280,900	$6,828,748
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$1,838,863	($1,838,863)	$0		$0
17	LESS: Charitable Donations	$60,981	($60,981)	$0		$0
18	Interest Expense on Customer Deposits	$3,641		$3,641		$3,641
19	Other Interest Expense/(Income)	$20,475		$20,475		$20,475
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$5,136,858	($1,613,126)	$3,523,732	$3,280,900	$6,804,632
21	**RATE BASE (from Line 38 below)**	$158,156,503	($34,936,272)	$123,220,232	$3,228,560	$126,448,791
22	**ROR EARNED ON AVERAGE RATE BASE**	3.2480%		2.8597%		5.3813%

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Schedule NS Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Rate Base** DESCRIPTION	**(1)** **Schedule NS Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **Schedule NS Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **Schedule NS Base Non-Fuel Additional Revenue Requirement**	**(5)** **Schedule NS Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$6,479,546	$0	$6,479,546		$6,479,546
24	Investor Funds Advanced	$1,850,372	$2,879,425	$4,729,796	$3,228,560	$7,958,356
25	Total Additions	$44,878,664	($37,585,521)	$7,293,143		$7,293,143
26	Total Deductions	($36,754,927)	$33,307,410	($3,447,517)		($3,447,517)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$16,453,654	($1,398,687)	$15,054,968	$3,228,560	$18,283,527
	NET UTILITY PLANT					
28	Utility Plant in Service	$200,586,888	$8,160,525	$208,747,412		$208,747,412
29	Acquisition Adjustments	$42,241	($42,241)	$0		$0
30	Construction Work in Progress	$45,337,306	($45,337,306)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$73,019,025	$3,389,193	$76,408,218		$76,408,218
32	Provision for Acquisition Adjustments	$7,213	($7,213)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$172,940,197	($40,601,002)	$132,339,194	$0	$132,339,194
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$368,147		$368,147		$368,147
35	Accumulated Deferred Income Taxes	$21,476,040	($6,913,259)	$14,562,781		$14,562,781
36	Other Cost Free Capital	$9,393,161	($150,159)	$9,243,002		$9,243,002
37	TOTAL RATE BASE DEDUCTIONS	$31,237,348	($7,063,417)	$24,173,930	$0	$24,173,930
38	**TOTAL RATE BASE**	$158,156,503	($34,936,272)	$123,220,232	$3,228,560	$126,448,791

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**6VP Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **6VP** **Cost of Service**	**(2)** **Ratemaking** **Adjustments**	**(3)** **6VP** **Fully Adjusted** **Cost of Service** (Col 1 + Col 2)	**(4)** **6VP** **Base Non-Fuel** **Additional Revenue** **Requirement**	**(5)** **6VP** **Fully Adjusted COS** **After Added Non-Fuel** **Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$11,790,962	($1,745,669)	$10,045,294	$2,021,063	$12,066,357
2	Forfeited Discounts and Misc. Service Revenues	$36,671	$2,338	$39,009	($8,098)	$30,911
3	Non-Fuel Rider Revenues	$223	($223)	$0		$0
4	Fuel Revenues	$10,169,761	($1,021,456)	$9,148,305		$9,148,305
5	Other Operating Revenues	$181,829	($2,029)	$179,799		$179,799
6	TOTAL OPERATING REVENUES	$22,179,446	($2,767,039)	$19,412,407	$2,012,965	$21,425,372
	OPERATING EXPENSES					
7	Fuel Expense	$10,320,965	($1,186,154)	$9,134,811		$9,134,811
8	Non-Fuel Operating and Maintenance Expense	$4,067,006	$1,199,046	$5,266,052	$17,608	$5,283,660
9	Depreciation and Amortization	$3,658,194	($60,969)	$3,597,226		$3,597,226
10	Federal Income Tax	$114,977	($456,342)	($341,364)	$394,869	$53,505
11	State Income Tax	$88,245	($132,984)	($44,738)	$115,026	$70,288
12	Taxes Other than Income Tax	$578,318	$23,943	$602,260		$602,260
13	(Gain)/Loss on Disposition of Property	$5,420	($11,371)	($5,951)		($5,951)
14	TOTAL ELECTRIC OPERATING EXPENSES	$18,833,126	($624,831)	$18,208,295	$527,504	$18,735,799
15	**NET OPERATING INCOME**	$3,346,320	($2,142,209)	$1,204,112	$1,485,461	$2,689,573
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$806,876	($806,876)	$0		$0
17	LESS: Charitable Donations	$23,924	($23,924)	$0		$0
18	Interest Expense on Customer Deposits	$1,688		$1,688		$1,688
19	Other Interest Expense/(Income)	$10,475		$10,475		$10,475
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$4,117,110	($2,925,161)	$1,191,949	$1,485,461	$2,677,410
21	**RATE BASE (from Line 38 below)**	$79,792,715	($14,967,670)	$64,825,046	$1,360,343	$66,185,389
22	**ROR EARNED ON AVERAGE RATE BASE**	5.1598%		1.8387%		4.0453%

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

6VP Class
Fully Adjusted Cost of Service and Revenue Requirement
Rate Base

LINE NO.	DESCRIPTION	(1) 6VP Cost of Service	(2) Ratemaking Adjustments	(3) 6VP Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) 6VP Base Non-Fuel Additional Revenue Requirement	(5) 6VP Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$2,796,547	$0	$2,796,547		$2,796,547
24	Investor Funds Advanced	$857,760	$1,334,175	$2,191,934	$1,360,343	$3,552,277
25	Total Additions	$16,913,602	($13,898,015)	$3,015,587		$3,015,587
26	Total Deductions	($14,400,745)	$12,740,037	($1,660,708)		($1,660,708)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$6,167,164	$176,197	$6,343,361	$1,360,343	$7,703,704
	NET UTILITY PLANT					
28	Utility Plant in Service	$105,216,371	$4,227,928	$109,444,300		$109,444,300
29	Acquisition Adjustments	$18,262	($18,262)	$0		$0
30	Construction Work in Progress	$19,991,104	($19,991,104)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$36,743,676	$1,715,728	$38,459,405		$38,459,405
32	Provision for Acquisition Adjustments	$3,118	($3,118)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$88,478,943	($17,494,048)	$70,984,895	$0	$70,984,895
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$170,631		$170,631		$170,631
35	Accumulated Deferred Income Taxes	$9,693,924	($2,269,703)	$7,424,221		$7,424,221
36	Other Cost Free Capital	$4,988,837	($80,478)	$4,908,359		$4,908,359
37	TOTAL RATE BASE DEDUCTIONS	$14,853,391	($2,350,181)	$12,503,210	$0	$12,503,210
38	**TOTAL RATE BASE**	$79,792,715	($14,967,670)	$64,825,046	$1,360,343	$66,185,389

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Street and Outdoor Lighting Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **St. & Out. Lighting Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **St. & Out. Lighting Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **St. & Out. Lighting Base Non-Fuel Additional Revenue Requirement**	**(5)** **St. & Out. Lighting Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$5,178,064	$72,495	$5,250,558	$2,067,295	$7,317,853
2	Forfeited Discounts and Misc. Service Revenues	$76,019	$1,716	$77,735	($31,835)	$45,901
3	Non-Fuel Rider Revenues	$0	$0	$0		$0
4	Fuel Revenues	$913,313	($91,734)	$821,579		$821,579
5	Other Operating Revenues	$67,943	($300)	$67,643		$67,643
6	TOTAL OPERATING REVENUES	$6,235,339	($17,822)	$6,217,516	$2,035,460	$8,252,976
	OPERATING EXPENSES					
7	Fuel Expense	$926,892	($106,525)	$820,368		$820,368
8	Non-Fuel Operating and Maintenance Expense	$2,612,364	$218,335	$2,830,699	$17,805	$2,848,504
9	Depreciation and Amortization	$2,366,402	$121,776	$2,488,178		$2,488,178
10	Federal Income Tax	($285,500)	($13,290)	($298,790)	$399,282	$100,492
11	State Income Tax	($52,958)	($3,875)	($56,833)	$116,311	$59,479
12	Taxes Other than Income Tax	$346,228	$12,913	$359,140		$359,140
13	(Gain)/Loss on Disposition of Property	$6,113	($6,647)	($534)		($534)
14	TOTAL ELECTRIC OPERATING EXPENSES	$5,919,540	$222,687	$6,142,228	$533,399	$6,675,626
15	**NET OPERATING INCOME**	$315,798	($240,510)	$75,289	$1,502,062	$1,577,350
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$83,438	($83,438)	$0		$0
17	LESS: Charitable Donations	$5,885	($5,885)	$0		$0
18	Interest Expense on Customer Deposits	$468		$468		$468
19	Other Interest Expense/(Income)	$4,987		$4,987		$4,987
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$387,896	($318,062)	$69,834	$1,502,062	$1,571,895
21	**RATE BASE (from Line 38 below)**	$36,292,242	($1,600,227)	$34,692,015	$265,094	$34,957,109
22	**ROR EARNED ON AVERAGE RATE BASE**	1.0688%		0.2013%		4.4966%

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Street and Outdoor Lighting Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Rate Base** DESCRIPTION	**(1)** **St. & Out. Lighting Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **St. & Out. Lighting Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **St. & Out. Lighting Base Non-Fuel Additional Revenue Requirement**	**(5)** **St. & Out. Lighting Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$825,133	$0	$825,133		$825,133
24	Investor Funds Advanced	$241,556	$375,078	$616,634	$265,094	$881,728
25	Total Additions	$1,880,281	($1,221,096)	$659,185		$659,185
26	Total Deductions	($1,992,706)	$1,127,905	($864,801)		($864,801)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$954,263	$281,887	$1,236,151	$265,094	$1,501,245
	NET UTILITY PLANT					
28	Utility Plant in Service	$61,503,206	$2,334,252	$63,837,458		$63,837,458
29	Acquisition Adjustments	$1,185	($1,185)	$0		$0
30	Construction Work in Progress	$3,279,163	($3,279,163)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$22,652,859	$1,090,347	$23,743,206		$23,743,206
32	Provision for Acquisition Adjustments	$202	($202)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$42,130,493	($2,036,241)	$40,094,252	$0	$40,094,252
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$47,328		$47,328		$47,328
35	Accumulated Deferred Income Taxes	$3,888,676	($106,781)	$3,781,896		$3,781,896
36	Other Cost Free Capital	$2,856,510	($47,347)	$2,809,163		$2,809,163
37	TOTAL RATE BASE DEDUCTIONS	$6,792,515	($154,127)	$6,638,387	$0	$6,638,387
38	**TOTAL RATE BASE**	$36,292,242	($1,600,227)	$34,692,015	$265,094	$34,957,109

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Traffic Lighting Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **Traffic Lighting Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **Traffic Lighting Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **Traffic Lighting Base Non-Fuel Additional Revenue Requirement**	**(5)** **Traffic Lighting Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
	Base Non-Fuel Rate Revenues, Including Facilities Charges &					
1	Load Management	$51,314	($357)	$50,957	$11,467	$62,424
2	Forfeited Discounts and Misc. Service Revenues	$899	$20	$919	($436)	$483
3	Non-Fuel Rider Revenues	$0	$0	$0		$0
4	Fuel Revenues	$16,290	($1,636)	$14,654		$14,654
5	Other Operating Revenues	$633	($3)	$630		$630
6	TOTAL OPERATING REVENUES	$69,136	($1,976)	$67,159	$11,031	$78,190
	OPERATING EXPENSES					
7	Fuel Expense	$16,532	($1,900)	$14,632		$14,632
8	Non-Fuel Operating and Maintenance Expense	$26,811	$3,137	$29,947	$96	$30,044
9	Depreciation and Amortization	$13,562	$280	$13,841		$13,841
10	Federal Income Tax	$100	($434)	($334)	$2,164	$1,830
11	State Income Tax	$226	($126)	$99	$630	$730
12	Taxes Other than Income Tax	$2,294	$102	$2,397		$2,397
13	(Gain)/Loss on Disposition of Property	$31	($41)	($10)		($10)
14	TOTAL ELECTRIC OPERATING EXPENSES	$59,555	$1,018	$60,574	$2,891	$63,464
15	**NET OPERATING INCOME**	$9,580	($2,994)	$6,586	$8,140	$14,726
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$1,435	($1,435)	$0		$0
17	LESS: Charitable Donations	$72	($72)	$0		$0
18	Interest Expense on Customer Deposits	$5		$5		$5
19	Other Interest Expense/(Income)	$34		$34		$34
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$10,904	($4,357)	$6,547	$8,140	$14,687
21	**RATE BASE (from Line 38 below)**	$245,747	($24,998)	$220,750	$2,149	$222,899
22	**ROR EARNED ON AVERAGE RATE BASE**	4.4370%		2.9657%		6.5891%

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

Traffic Lighting Class
Fully Adjusted Cost of Service and Revenue Requirement
Rate Base

LINE NO.	DESCRIPTION	(1) Traffic Lighting Cost of Service	(2) Ratemaking Adjustments	(3) Traffic Lighting Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) Traffic Lighting Base Non-Fuel Additional Revenue Requirement	(5) Traffic Lighting Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$6,561	$0	$6,561		$6,561
24	Investor Funds Advanced	$2,677	$4,159	$6,835	$2,149	$8,985
25	Total Additions	$29,108	($22,425)	$6,683		$6,683
26	Total Deductions	($33,453)	$23,397	($10,056)		($10,056)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$4,892	$5,131	$10,023	$2,149	$12,173
	NET UTILITY PLANT					
28	Utility Plant in Service	$375,591	$14,584	$390,175		$390,175
29	Acquisition Adjustments	$30	($30)	$0		$0
30	Construction Work in Progress	$41,663	($41,663)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$131,613	$6,263	$137,877		$137,877
32	Provision for Acquisition Adjustments	$5	($5)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$285,666	($33,367)	$252,298	$0	$252,298
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$525		$525		$525
35	Accumulated Deferred Income Taxes	$27,611	($2,966)	$24,646		$24,646
36	Other Cost Free Capital	$16,674	($273)	$16,401		$16,401
37	TOTAL RATE BASE DEDUCTIONS	$44,810	($3,238)	$41,572	$0	$41,572
38	**TOTAL RATE BASE**	$245,747	($24,998)	$220,750	$2,149	$222,899

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Total of All North Carolina Classes** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **Total NC Jurisdiction Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **Total NC Jurisdiction Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **Total NC Jurisdiction Base Non-Fuel Additional Revenue Requirement**	**(5)** **Total NC Jurisdiction Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$246,761,884	$7,840,847	$254,602,731	$56,883,021	$311,485,752
2	Forfeited Discounts and Misc. Service Revenues	$1,253,489	$52,361	$1,305,850	($259,047)	$1,046,803
3	Non-Fuel Rider Revenues	$4,604,409	($4,604,409)	$0	$0	$0
4	Fuel Revenues	$152,244,208	($15,291,487)	$136,952,721	$0	$136,952,721
5	Other Operating Revenues	$3,332,375	($20,146)	$3,312,229	$0	$3,312,229
6	TOTAL OPERATING REVENUES	$408,196,365	($12,022,834)	$396,173,531	$56,623,974	$452,797,505
	OPERATING EXPENSES					
7	Fuel Expense	$154,507,777	($17,757,061)	$136,750,716	$0	$136,750,716
8	Non-Fuel Operating and Maintenance Expense	$84,631,351	$17,432,677	$102,064,028	$495,315	$102,559,343
9	Depreciation and Amortization	$76,966,815	($38,935)	$76,927,880	$0	$76,927,880
10	Federal Income Tax	$3,766,678	($673,265)	$3,093,413	$11,107,535	$14,200,947
11	State Income Tax	$2,295,427	($196,997)	$2,098,430	$3,235,638	$5,334,068
12	Taxes Other than Income Tax	$12,635,649	$509,630	$13,145,279	$0	$13,145,279
13	(Gain)/Loss on Disposition of Property	$156,151	($245,242)	($89,091)	$0	($89,091)
14	TOTAL ELECTRIC OPERATING EXPENSES	$334,959,847	($969,192)	$333,990,655	$14,838,487	$348,829,142
15	**NET OPERATING INCOME**	$73,236,518	($11,053,642)	$62,182,876	$41,785,487	$103,968,363
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$14,108,009	($14,108,009)	$0	$0	$0
17	LESS: Charitable Donations	$397,631	($397,631)	$0	$0	$0
18	Interest Expense on Customer Deposits	$31,017	$0	$31,017	$0	$31,017
19	Other Interest Expense/(Income)	$212,619	$0	$212,619	$0	$212,619
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$86,703,259	($24,764,019)	$61,939,239	$41,785,487	$103,724,727
21	**RATE BASE (from Line 38 below)**	$1,594,851,513	($264,726,022)	$1,330,125,491	$23,200,860	$1,353,326,351
22	**ROR EARNED ON AVERAGE RATE BASE**	5.4364%		4.6566%		7.6644%

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Total of All North Carolina Classes** **Fully Adjusted Cost of Service and Revenue Requirement** **Rate Base** DESCRIPTION	**(1)** **Total NC Jurisdiction Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **Total NC Jurisdiction Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **Total NC Jurisdiction Base Non-Fuel Additional Revenue Requirement**	**(5)** **Total NC Jurisdiction Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$50,733,308	$0	$50,733,308	$0	$50,733,308
24	Investor Funds Advanced	$15,791,563	$24,554,504	$40,346,067	$23,200,860	$63,546,927
25	Total Additions	$264,540,117	($212,291,872)	$52,248,245	$0	$52,248,245
26	Total Deductions	($236,039,996)	$200,899,380	($35,140,616)	$0	($35,140,616)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$95,024,991	$13,162,012	$108,187,004	$23,200,860	$131,387,864
	NET UTILITY PLANT					
28	Utility Plant in Service	$2,269,147,992	$90,049,544	$2,359,197,536	$0	$2,359,197,536
29	Acquisition Adjustments	$313,057	($313,057)	$0	$0	$0
30	Construction Work in Progress	$360,345,332	($360,345,332)	$0	$0	$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$833,761,769	$38,926,938	$872,688,708	$0	$872,688,708
32	Provision for Acquisition Adjustments	$53,457	($53,457)	($0)	$0	($0)
33	TOTAL NET UTILITY PLANT	$1,795,991,155	($309,482,326)	$1,486,508,829	$0	$1,486,508,829
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$3,135,948	$0	$3,135,948	$0	$3,135,948
35	Accumulated Deferred Income Taxes	$185,445,996	($29,846,253)	$155,599,743	$0	$155,599,743
36	Other Cost Free Capital	$107,582,689	($1,748,038)	$105,834,651	$0	$105,834,651
37	TOTAL RATE BASE DEDUCTIONS	$296,164,633	($31,594,291)	$264,570,342	$0	$264,570,342
38	**TOTAL RATE BASE**	$1,594,851,513	($264,726,022)	$1,330,125,491	$23,200,860	$1,353,326,351

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
SUMMARY OF NORTH CAROLINA JURISDICTION AND CUSTOMER CLASS RATES OF RETURN
PER BOOKS, ANNUALIZED, FULLY ADJUSTED AND FULLY ADJUSTED WITH INCREASE

PER BOOKS CLASS RATE OF RETURNS - FROM ITEM 45a

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$86,703,259	$47,069,722	$18,110,013	$11,870,756	$5,136,858	$4,117,110	$387,896	$10,904
Rate Base	$1,594,851,513	$823,640,771	$318,044,620	$178,678,915	$158,156,503	$79,792,715	$36,292,242	$245,747
ROR	5.4364%	5.7148%	5.6942%	6.6436%	3.2480%	5.1598%	1.0688%	4.4370%
Index		1.05	1.05	1.22	0.60	0.95	0.20	0.82

PER BOOKS CLASS RATE OF RETURNS WITH ANNUALIZED REVENUE - FROM ITEM 45b

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$84,327,736	$49,277,746	$17,387,206	$9,071,447	$5,556,622	$2,652,793	$373,302	$8,620
Rate Base	$1,594,851,513	$823,640,771	$318,044,620	$178,678,915	$158,156,503	$79,792,715	$36,292,242	$245,747
ROR	5.2875%	5.9829%	5.4669%	5.0770%	3.5134%	3.3246%	1.0286%	3.5077%
Index		1.13	1.03	0.96	0.66	0.63	0.19	0.66

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS BEFORE REVENUE INCREASE - FROM ITEM 45c, COL. 3

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$61,939,239	$39,281,392	$12,733,509	$5,132,276	$3,523,732	$1,191,949	$69,834	$6,547
Rate Base	$1,330,125,491	$696,222,134	$265,887,221	$145,058,094	$123,220,232	$64,825,046	$34,692,015	$220,750
ROR	4.6566%	5.6421%	4.7891%	3.5381%	2.8597%	1.8387%	0.2013%	2.9657%
Index		1.21	1.03	0.76	0.61	0.39	0.04	0.64

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS AND AFTER REVENUE INCREASE - FROM ITEM 45c, COLS. 4 & 5

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Revenue Increase	$56,623,974	$29,876,494	$12,786,745	$5,455,296	$4,445,983	$2,012,965	$2,035,460	$11,031
Adjusted NOI	$103,724,727	$61,328,659	$22,169,448	$9,157,995	$6,804,632	$2,677,410	$1,571,895	$14,687
Rate Base	$1,353,326,351	$706,768,613	$270,549,802	$148,193,748	$126,448,791	$66,185,389	$34,957,109	$222,899
ROR	7.6644%	8.6773%	8.1942%	6.1797%	5.3813%	4.0453%	4.4966%	6.5891%
Index		1.13	1.07	0.81	0.70	0.53	0.59	0.86

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 62.2213%
Demand 37.7787%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	NOI (COS Sch 1, Ln 36)	$47,069,722	$6,786,496	$7,332,283	$12,076,227	$19,408,510	$9,435,692	$9,402,021	$2,037,002
2	NOI Ratio (Based on Ln 1)	100.0000%	14.4180%	15.5775%	25.6560%	41.2335%	20.0462%	19.9747%	4.3276%
3	Rate Base (COS Sch 1, Ln 38)	$823,640,771	$118,752,245	$128,302,587	$211,313,618	$339,616,205	$165,108,701	$164,519,519	$35,644,101
4	Rate Base Ratio (Based on Ln 3)	100.0000%	14.4180%	15.5775%	25.6560%	41.2335%	20.0462%	19.9747%	4.3276%
5	Rate of Return (Ln 1 / Ln 3)	5.71%	5.71%	5.71%	5.71%	5.71%	5.71%	5.71%	5.71%

PART B

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
6	Change in NOI (Item 45b, Pg 1, Col 2, Ln 20)	$2,208,024							
7	Allocated on NOI Ratio (Ln 2)	$2,208,023	$318,352	$343,955	$566,491	$910,446	$442,625	$441,045	$95,555
8	Annualized NOI (Ln 1 + Ln 7)	$49,277,746	$7,104,848	$7,676,238	$12,642,718	$20,318,956	$9,878,317	$9,843,066	$2,132,557
9	Annualized Rate of Return (Ln 8 / Ln 3)	5.98%	5.98%	5.98%	5.98%	5.98%	5.98%	5.98%	5.98%

PART C

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
10	NOI After All Adjustments and Increase	$61,328,659 *							
11	Allocated on NOI Ratio	$61,328,660	$8,842,345	$9,553,468	$15,734,506	$25,287,974	$12,294,068	$12,250,197	$2,654,076
12	Final Rate Base After All Adjustments	$706,768,613 #							
13	Allocated on Rate Base Ratio	$706,768,613	$101,901,657	$110,096,834	$181,328,849	$291,425,683	$141,680,271	$141,174,692	$30,586,310
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	8.68%	8.68%	8.68%	8.68%	8.68%	8.68%	8.68%	8.68%

*** Total from NCUC Form E-1, Item 45c, Page 1, Column 5, Line 20**
 # Total from NCUC Form E-1, Item 45c, Page 1, Column 5, Line 21

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 62.2213%
Demand 37.7787%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	NOI (COS Sch 1, Ln 36)	$18,110,013	$1,278,485	$3,025,254	$4,982,576	$8,007,830	$3,916,211	$3,913,201	$994,285
2	NOI Ratio (Based on Ln 1)	100.0000%	7.0595%	16.7049%	27.5128%	44.2177%	21.6246%	21.6079%	5.4903%
3	Rate Base (COS Sch 1, Ln 38)	$318,044,620	$22,452,510	$53,128,939	$87,503,054	$140,631,993	$68,775,761	$68,722,903	$17,461,453
4	Rate Base Ratio (Based on Ln 3)	100.0000%	7.0595%	16.7049%	27.5128%	44.2177%	21.6246%	21.6079%	5.4903%
5	Rate of Return (Ln 1 / Ln 3)	5.69%	5.69%	5.69%	5.69%	5.69%	5.69%	5.69%	5.69%

PART B

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
6	Change in NOI (Item 45b, Pg 2, Col 2, Ln 20)	($722,807)							
7	Allocated on NOI Ratio (Ln 2)	($722,807)	($51,027)	($120,744)	($198,865)	($319,608)	($156,304)	($156,184)	($39,684)
8	Annualized NOI (Ln 1 + Ln 7)	$17,387,206	$1,227,458	$2,904,510	$4,783,711	$7,688,222	$3,759,907	$3,757,017	$954,601
9	Annualized Rate of Return (Ln 8 / Ln 3)	5.47%	5.47%	5.47%	5.47%	5.47%	5.47%	5.47%	5.47%

PART C

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
10	NOI After All Adjustments and Increase	$22,169,448 *							
11	Allocated on NOI Ratio	$22,169,448	$1,565,063	$3,703,377	$6,099,441	$9,802,818	$4,794,046	$4,790,362	$1,217,159
12	Final Rate Base After All Adjustments	$270,549,802 #							
13	Allocated on Rate Base Ratio	$270,549,802	$19,099,591	$45,194,992	$74,435,889	$119,630,880	$58,505,214	$58,460,249	$14,853,868
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	8.19%	8.19%	8.19%	8.19%	8.19%	8.19%	8.19%	8.19%

*** Total from NCUC Form E-1, Item 45c, Page 3, Column 5, Line 20**
 # Total from NCUC Form E-1, Item 45c, Page 3, Column 5, Line 21

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 62.2213%
Demand 37.7787%

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
1	NOI (COS Sch 1, Ln 36)	$11,870,756	$34,486	$2,304,372	$3,795,286	$6,099,658	$2,994,111	$1,855,771	$886,730
2	NOI Ratio (Based on Ln 1)	100.0000%	0.2905%	19.4122%	31.9717%	51.3839%	25.2226%	15.6331%	7.4699%
3	Rate Base (COS Sch 1, Ln 38)	$178,678,915	$519,088	$34,685,458	$57,126,748	$91,812,206	$45,067,429	$27,933,106	$13,347,086
4	Rate Base Ratio (Based on Ln 3)	100.0000%	0.2905%	19.4122%	31.9717%	51.3839%	25.2226%	15.6331%	7.4699%
5	Rate of Return (Ln 1 / Ln 3)	6.64%	6.64%	6.64%	6.64%	6.64%	6.64%	6.64%	6.64%

PART B

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
6	Change in NOI (Item 45b, Pg 3, Col 2, Ln 20)	($2,799,310)							
7	Allocated on NOI Ratio (Ln 2)	($2,799,310)	($8,132)	($543,407)	($894,988)	($1,438,395)	($706,058)	($437,620)	($209,105)
8	Annualized NOI (Ln 1 + Ln 7)	$9,071,447	$26,354	$1,760,965	$2,900,298	$4,661,263	$2,288,053	$1,418,151	$677,625
9	Annualized Rate of Return (Ln 8 / Ln 3)	5.08%	5.08%	5.08%	5.08%	5.08%	5.08%	5.08%	5.08%

PART C

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
10	NOI After All Adjustments and Increase	$9,157,995 *							
11	Allocated on NOI Ratio	$9,157,993	$26,605	$1,777,766	$2,927,969	$4,705,735	$2,309,882	$1,431,681	$684,090
12	Final Rate Base After All Adjustments	$148,193,748 #							
13	Allocated on Rate Base Ratio	$148,193,747	$430,524	$28,767,625	$47,380,111	$76,147,736	$37,378,284	$23,167,320	$11,069,883
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	6.18%	6.18%	6.18%	6.18%	6.18%	6.18%	6.18%	6.18%

*** Total from NCUC Form E-1, Item 45c, Page 5, Column 5, Line 20**
 # Total from NCUC Form E-1, Item 45c, Page 5, Column 5, Line 21

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 62.2213%
Demand 37.7787%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	NOI (COS Sch 1, Ln 36)	$5,136,858	$2,096	$1,162,519	$1,914,663	$3,077,182	$1,520,875	$0	$536,705
2	NOI Ratio (Based on Ln 1)	100.0000%	0.0408%	22.6309%	37.2730%	59.9040%	29.6071%	0.0000%	10.4481%
3	Rate Base (COS Sch 1, Ln 38)	$158,156,503	$64,537	$35,792,313	$58,949,733	$94,742,046	$46,825,559	$0	$16,524,362
4	Rate Base Ratio (Based on Ln 3)	100.0000%	0.0408%	22.6309%	37.2730%	59.9040%	29.6071%	0.0000%	10.4481%
5	Rate of Return (Ln 1 / Ln 3)	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	#DIV/0!	3.25%

PART B

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
6	Change in NOI (Item 45b, Pg 4, Col 2, Ln 20)	$419,764							
7	Allocated on NOI Ratio (Ln 2)	$419,763	$171	$94,997	$156,459	$251,455	$124,280	$0	$43,857
8	Annualized NOI (Ln 1 + Ln 7)	$5,556,622	$2,267	$1,257,516	$2,071,122	$3,328,637	$1,645,155	$0	$580,562
9	Annualized Rate of Return (Ln 8 / Ln 3)	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	#DIV/0!	3.51%

PART C

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
10	NOI After All Adjustments and Increase	$6,804,632 *							
11	Allocated on NOI Ratio	$6,804,631	$2,777	$1,539,952	$2,536,294	$4,076,245	$2,014,654	$0	$710,955
12	Final Rate Base After All Adjustments	$126,448,791 #							
13	Allocated on Rate Base Ratio	$126,448,792	$51,599	$28,616,558	$47,131,305	$75,747,863	$37,437,824	$0	$13,211,506
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	5.38%	5.38%	5.38%	5.38%	5.38%	5.38%	#DIV/0!	5.38%

*** Total from NCUC Form E-1, Item 45c, Page 7, Column 5, Line 20**
 # Total from NCUC Form E-1, Item 45c, Page 7, Column 5, Line 21

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 62.2213%
Demand 37.7787%

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
1	NOI (COS Sch 1, Ln 36)	$4,117,110	$3,272	$801,243	$1,319,643	$2,120,886	$1,045,452	$639,046	$308,454
2	NOI Ratio (Based on Ln 1)	100.0000%	0.0795%	19.4613%	32.0526%	51.5139%	25.3929%	15.5217%	7.4920%
3	Rate Base (COS Sch 1, Ln 38)	$79,792,715	$63,411	$15,528,699	$25,575,676	$41,104,375	$20,261,661	$12,385,189	$5,978,079
4	Rate Base Ratio (Based on Ln 3)	100.0000%	0.0795%	19.4613%	32.0526%	51.5139%	25.3929%	15.5217%	7.4920%
5	Rate of Return (Ln 1 / Ln 3)	5.16%	5.16%	5.16%	5.16%	5.16%	5.16%	5.16%	5.16%

PART B

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
6	Change in NOI (Item 45b, Pg 5, Col 2, Ln 20)	($1,464,317)							
7	Allocated on NOI Ratio (Ln 2)	($1,464,317)	($1,164)	($284,975)	($469,352)	($754,327)	($371,832)	($227,287)	($109,707)
8	Annualized NOI (Ln 1 + Ln 7)	$2,652,793	$2,108	$516,268	$850,291	$1,366,559	$673,620	$411,759	$198,747
9	Annualized Rate of Return (Ln 8 / Ln 3)	3.32%	3.32%	3.32%	3.32%	3.32%	3.32%	3.32%	3.32%

PART C

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
10	NOI After All Adjustments and Increase	$2,677,410 *							
11	Allocated on NOI Ratio	$2,677,411	$2,128	$521,059	$858,181	$1,379,240	$679,871	$415,580	$200,592
12	Final Rate Base After All Adjustments	$66,185,389 #							
13	Allocated on Rate Base Ratio	$66,185,387	$52,597	$12,880,536	$21,214,168	$34,094,704	$16,806,370	$10,273,100	$4,958,616
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	4.05%	4.05%	4.05%	4.05%	4.05%	4.05%	4.05%	4.05%

*** Total from NCUC Form E-1, Item 45c, Page 9, Column 5, Line 20**
 # Total from NCUC Form E-1, Item 45c, Page 9, Column 5, Line 21

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A — **STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS**

Energy 62.2213%
Demand 37.7787%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	NOI (COS Sch 1, Ln 36)	$387,896	$323,904	$10,416	$17,156	$27,572	$14,025	$16,149	$6,247
2	NOI Ratio (Based on Ln 1)	100.0000%	83.5027%	2.6853%	4.4227%	7.1080%	3.6157%	4.1631%	1.6105%
3	Rate Base (COS Sch 1, Ln 38)	$36,292,242	$30,305,016	$974,558	$1,605,092	$2,579,650	$1,312,206	$1,510,892	$584,478
4	Rate Base Ratio (Based on Ln 3)	100.0000%	83.5027%	2.6853%	4.4227%	7.1080%	3.6157%	4.1631%	1.6105%
5	Rate of Return (Ln 1 / Ln 3)	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%

PART B — **STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR**

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
6	Change in NOI (Item 45b, Pg 6, Col 2, Ln 20)	($14,594)							
7	Allocated on NOI Ratio (Ln 2)	($14,594)	($12,186)	($392)	($645)	($1,037)	($528)	($608)	($235)
8	Annualized NOI (Ln 1 + Ln 7)	$373,302	$311,718	$10,024	$16,511	$26,535	$13,497	$15,541	$6,012
9	Annualized Rate of Return (Ln 8 / Ln 3)	1.03%	1.03%	1.03%	1.03%	1.03%	1.03%	1.03%	1.03%

PART C — **STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR**

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
10	NOI After All Adjustments and Increase	$1,571,895 *							
11	Allocated on NOI Ratio	$1,571,895	$1,312,576	$42,209	$69,521	$111,730	$56,834	$65,440	$25,315
12	Final Rate Base After All Adjustments	$34,957,109 #							
13	Allocated on Rate Base Ratio	$34,957,109	$29,190,144	$938,706	$1,546,044	$2,484,749	$1,263,932	$1,455,308	$562,976
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%

*** Total from NCUC Form E-1, Item 45c, Page 11, Column 5, Line 20**
 # Total from NCUC Form E-1, Item 45c, Page 11, Column 5, Line 21

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 62.2213%
Demand 37.7787%

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
1	NOI (COS Sch 1, Ln 36)	$10,904	$5,270	$1,170	$1,928	$3,098	$1,494	$703	$338
2	NOI Ratio (Based on Ln 1)	100.0000%	48.3312%	10.7301%	17.6786%	28.4087%	13.7054%	6.4517%	3.1030%
3	Rate Base (COS Sch 1, Ln 38)	$245,747	$118,773	$26,375	$43,439	$69,814	$33,681	$15,855	$7,626
4	Rate Base Ratio (Based on Ln 3)	100.0000%	48.3312%	10.7326%	17.6761%	28.4087%	13.7054%	6.4517%	3.1030%
5	Rate of Return (Ln 1 / Ln 3)	4.44%	4.44%	4.44%	4.44%	4.44%	4.44%	4.44%	4.44%

PART B

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
6	Change in NOI (Item 45b, Pg 7, Col 2, Ln 20)	($2,284)							
7	Allocated on NOI Ratio (Ln 2)	($2,284)	($1,104)	($245)	($404)	($649)	($313)	($147)	($71)
8	Annualized NOI (Ln 1 + Ln 7)	$8,620	$4,166	$925	$1,524	$2,449	$1,181	$556	$267
9	Annualized Rate of Return (Ln 8 / Ln 3)	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%

PART C

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
10	NOI After All Adjustments and Increase	$14,687 *							
11	Allocated on NOI Ratio	$14,687	$7,098	$1,576	$2,596	$4,172	$2,013	$948	$456
12	Final Rate Base After All Adjustments	$222,899 #							
13	Allocated on Rate Base Ratio	$222,900	$107,730	$23,923	$39,400	$63,323	$30,549	$14,381	$6,917
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	6.59%	6.59%	6.59%	6.59%	6.59%	6.59%	6.59%	6.59%

*** Total from NCUC Form E-1, Item 45c, Page 13, Column 5, Line 20**
 # Total from NCUC Form E-1, Item 45c, Page 13, Column 5, Line 21

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 62.2213%
Demand 37.7787%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$192,922,208	$25,216,128	$18,588,790	$30,615,629	$49,204,419	$17,798,066	$27,747,491	$72,956,105
2	NOI (COS Sch 1, Ln 36)	$47,069,722	$6,786,496	$7,332,283	$12,076,227	$19,408,510	$9,435,692	$9,402,021	$2,037,002
3	NOI Ratio (Based on Ln 1)	100.0000%	14.4180%	15.5775%	25.6560%	41.2335%	20.0462%	19.9747%	4.3276%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($60,621,360)							($60,621,360)
5	Removal of Rider Revenues (on NOI Ratio)	($2,842,691)	($409,858)	($442,820)	($729,322)	($1,172,142)	($569,852)	($567,818)	($123,021)
6	Removal of Facilities Charges (on NOI Ratio)	($96)	($14)	($15)	($25)	($40)	($19)	($19)	($4)
7	Removal of Load Management (assigned to production)	$39		$15	$24	$39			
8	COS Per Books Base Rate Revenue	$129,458,100	$24,806,256	$18,145,970	$29,886,307	$48,032,276	$17,228,195	$27,179,653	$12,211,720

PART B

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
9	Annualized Rate Revenue Adjustment	$2,985,398							
10	Allocated on NOI Ratio (Ln 3)	$2,985,398	$430,434	$465,050	$765,935	$1,230,985	$598,459	$596,323	$129,197
11	Total Revenues (Ln 8 + Ln 10)	$132,443,498	$25,236,689	$18,611,020	$30,652,242	$49,263,261	$17,826,654	$27,775,977	$12,340,917
12	Annualized Billing Units		1,296,996	1,520,481,017	1,520,481,017	1,520,481,017	1,520,481,017	1,520,481,017	1,520,481,017
13	Unit Costs based on Annualized Revenues		$19.46 per month	$0.012240 per kWh	$0.020160 per kWh	$0.032400 per kWh	$0.011724 per kWh	$0.018268 per kWh	$0.008116 per kWh

PART C

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
14	Fully Adjusted Rate Revenue Adjustment	11,085,819							
15	Allocated on NOI Ratio (Ln 3)	11,085,819	1,598,350	1,726,893	$2,844,182	4,571,075	2,222,286	2,214,356	479,753
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$140,543,919	$26,404,605	$19,872,862	$32,730,489	$52,603,351	$19,450,480	$29,394,009	$12,691,473
17	Fully Adjusted Billing Units		1,317,564	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840
18	Unit Costs based on Fully Adjusted Cost of Service		$20.04 per month	$0.012246 per kWh	$0.020170 per kWh	$0.032416 per kWh	$0.011986 per kWh	$0.018114 per kWh	$0.007821 per kWh

PART D

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
19	Proposed Rate Revenue Adjustment	$30,043,524							
20	Allocated on NOI Ratio (Ln 3)	$30,043,524	$4,331,665	$4,680,028	$7,707,979	$12,388,007	$6,022,586	$6,001,094	$1,300,172
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$170,587,442	$30,736,270	$24,552,890	$40,438,468	$64,991,358	$25,473,066	$35,395,103	$13,991,644
22	Fully Adjusted Billing Units		1,317,564	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840
23	Unit Costs based on Proposed Revenue Requirement		$23.33 per month	$0.015130 per kWh	$0.024920 per kWh	$0.040050 per kWh	$0.015697 per kWh	$0.021812 per kWh	$0.008622 per kWh

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 62.2213%
Demand 37.7787%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$82,094,139	$5,306,737	$7,691,892	$12,668,501	$20,360,393	$7,394,473	$13,297,138	$35,735,398
2	NOI (COS Sch 1, Ln 36)	$18,110,013	$1,278,485	$3,025,254	$4,982,576	$8,007,830	$3,916,211	$3,913,201	$994,285
3	NOI Ratio (Based on Ln 1)	100.0000%	7.0595%	16.7049%	27.5128%	44.2177%	21.6246%	21.6079%	5.4903%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($29,697,669)							($29,697,669)
5	Removal of Rider Revenues (on NOI Ratio)	($1,325,418)	($93,568)	($221,409)	($364,660)	($586,069)	($286,616)	($286,395)	($72,769)
6	Removal of Facilities Charges (on NOI Ratio)	($616,355)	($43,512)	($102,961)	($169,577)	($272,538)	($133,284)	($133,182)	($33,839)
7	Removal of Load Management (assigned to production)	$16		$6	$10	$16			
8	COS Per Books Base Rate Revenue	$50,454,714	$5,169,657	$7,367,527	$12,134,274	$19,501,802	$6,974,574	$12,877,561	$5,931,121

PART B

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
9	Annualized Rate Revenue Adjustment	($981,351)							
10	Allocated on NOI Ratio (Ln 3)	($981,351)	($69,279)	($163,933)	($269,997)	($433,931)	($212,213)	($212,050)	($53,879)
11	Total Revenues (Ln 8 + Ln 10)	$49,473,363	$5,100,378	$7,203,594	$11,864,277	$19,067,871	$6,762,361	$12,665,511	$5,877,242
12	Annualized Billing Units		217,116	745,580,278	745,580,278	745,580,278	745,580,278	745,580,278	745,580,278
13	Unit Costs based on Annualized Revenues		$23.49 per month	$0.009662 per kWh	$0.015913 per kWh	$0.025575 per kWh	$0.009070 per kWh	$0.016987 per kWh	$0.007883 per kWh

PART C

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
14	Fully Adjusted Rate Revenue Adjustment	$16,293							
15	Allocated on NOI Ratio (Ln 3)	$16,293	$1,150	$2,722	$4,483	$7,204	$3,523	$3,521	$895
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$50,471,007	$5,170,807	$7,370,249	$12,138,757	$19,509,006	$6,978,097	$12,881,082	$5,932,015
17	Fully Adjusted Billing Units		221,052	761,872,918	761,872,918	761,872,918	761,872,918	761,872,918	761,872,918
18	Unit Costs based on Fully Adjusted Cost of Service		$23.39 per month	$0.009674 per kWh	$0.015933 per kWh	$0.025607 per kWh	$0.009159 per kWh	$0.016907 per kWh	$0.007786 per kWh

PART D

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
19	Proposed Rate Revenue Adjustment	$12,973,749							
20	Allocated on NOI Ratio (Ln 3)	$12,973,749	$915,888	$2,167,248	$3,569,445	$5,736,693	$2,805,517	$2,803,360	$712,292
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$63,444,756	$6,086,695	$9,537,497	$15,708,202	$25,245,699	$9,783,613	$15,684,442	$6,644,307
22	Fully Adjusted Billing Units		221,052	761,872,918	761,872,918	761,872,918	761,872,918	761,872,918	761,872,918
23	Unit Costs based on Proposed Revenue Requirement		$27.54 per month	$0.012518 per kWh	$0.020618 per kWh	$0.033136 per kWh	$0.012842 per kWh	$0.020587 per kWh	$0.008721 per kWh

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 62.2213%
Demand 37.7787%

		Total	Customer	Demand: Production Demand	Demand: Production Energy	Demand: Production Combined	Demand: Transmission	Demand: Distribution	Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$53,092,029	$124,077	$5,467,131	$9,004,334	$14,471,465	$5,426,034	$5,594,471	$27,475,982
2	NOI (COS Sch 1, Ln 36)	$11,870,756	$34,486	$2,304,372	$3,795,286	$6,099,658	$2,994,111	$1,855,771	$886,730
3	NOI Ratio (Based on Ln 1)	100.0000%	0.2905%	19.4122%	31.9717%	51.3839%	25.2226%	15.6331%	7.4699%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($22,690,325)							($22,690,325)
5	Removal of Rider Revenues (on NOI Ratio)	($436,077)	($1,267)	($84,652)	($139,421)	($224,073)	($109,990)	($68,172)	($32,574)
6	Removal of Facilities Charges (on NOI Ratio)	($418,566)	($1,216)	($81,253)	($133,823)	($215,076)	($105,573)	($65,435)	($31,266)
7	Removal of Load Management (assigned to production)	$10		$4	$7	$10			
8	COS Per Books Base Rate Revenue	$29,547,072	$121,594	$5,301,230	$8,731,096	$14,032,327	$5,210,471	$5,460,864	$4,721,817

PART B

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

		Total	Customer	Demand: Production Demand	Demand: Production Energy	Demand: Production Combined	Demand: Transmission	Demand: Distribution	Energy
9	Annualized Rate Revenue Adjustment	($3,832,401)							
10	Allocated on NOI Ratio (Ln 3)	($3,832,401)	($11,134)	($743,952)	($1,225,285)	($1,969,237)	($966,630)	($599,124)	($286,275)
11	Total Revenues (Ln 8 + Ln 10)	$25,714,671	$110,460	$4,557,278	$7,505,812	$12,063,089	$4,243,840	$4,861,739	$4,435,541
12	Annualized Billing Units		660	1,248,843	572,194,905	1,248,843	1,349,735	1,349,735	572,194,905
13	Unit Costs based on Annualized Revenues		$167.36 per month	$3.649200 per kW	$0.013118 per kWh	$9.659412 per kW	$3.144203 per kW	$3.601996 per kW	$0.007752 per kWh

PART C

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

		Total	Customer	Demand: Production Demand	Demand: Production Energy	Demand: Production Combined	Demand: Transmission	Demand: Distribution	Energy
14	Fully Adjusted Rate Revenue Adjustment	($4,374,050)							
15	Allocated on NOI Ratio (Ln 3)	($4,374,050)	($12,707)	($849,098)	($1,398,460)	($2,247,558)	($1,103,248)	($683,801)	($326,736)
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$25,173,022	$108,887	$4,452,132	$7,332,637	$11,784,769	$4,107,223	$4,777,063	$4,395,081
17	Fully Adjusted Billing Units		672	1,228,152	562,714,493	1,228,152	1,327,372	1,327,372	562,714,493
18	Unit Costs based on Fully Adjusted Cost of Service		$162.03 per month	$3.625066 per kW	$0.013031 per kWh	$9.595530 per kW	$3.094251 per kW	$3.598888 per kW	$0.007810 per kWh

PART D

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

		Total	Customer	Demand: Production Demand	Demand: Production Energy	Demand: Production Combined	Demand: Transmission	Demand: Distribution	Energy
19	Proposed Rate Revenue Adjustment	$5,414,139							
20	Allocated on NOI Ratio (Ln 3)	$5,414,139	$15,729	$1,051,002	$1,730,994	$2,781,996	$1,365,585	$846,399	$404,429
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$30,587,161	$124,616	$5,503,134	$9,063,631	$14,566,765	$5,472,808	$5,623,462	$4,799,510
22	Fully Adjusted Billing Units		672	1,228,152	562,714,493	1,228,152	1,327,372	1,327,372	562,714,493
23	Unit Costs based on Proposed Revenue Requirement		$185.44 per month	$4.480825 per kW	$0.016107 per kWh	$11.860718 per kW	$4.123040 per kW	$4.236538 per kW	$0.008529 per kWh

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 62.2213%
Demand 37.7787%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$47,382,198	$12,125	$3,998,730	$6,585,886	$10,584,616	$3,480,297	$0	$33,305,160
2	NOI (COS Sch 1, Ln 36)	$5,136,858	$2,096	$1,162,519	$1,914,663	$3,077,182	$1,520,875	$0	$536,705
3	NOI Ratio (Based on Ln 1)	100.0000%	0.0408%	22.6309%	37.2730%	59.9040%	29.6071%	0.0000%	10.4481%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($28,135,491)							($28,135,491)
5	Removal of Rider Revenues (on NOI Ratio)	$0	$0	$0	$0	$0	$0	$0	$0
6	Removal of Facilities Charges (on NOI Ratio)	($7,479)	($3)	($1,693)	($2,788)	($4,480)	($2,214)	$0	($781)
7	Removal of Load Management (assigned to production)	$11		$4	$7	$11			
8	COS Per Books Base Rate Revenue	$19,239,239	$12,122	$3,997,042	$6,583,105	$10,580,146	$3,478,083	$0	$5,168,888

PART B

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
9	Annualized Rate Revenue Adjustment	$566,063							
10	Allocated on NOI Ratio (Ln 3)	$566,063	$231	$128,105	$210,989	$339,094	$167,595	$0	$59,143
11	Total Revenues (Ln 8 + Ln 10)	$19,805,302	$12,353	$4,125,147	$6,794,094	$10,919,241	$3,645,677	$0	$5,228,031
12	Annualized Billing Units		12	2,037,077	657,936,799	657,936,799	2,037,077	2,037,077	657,936,799
13	Unit Costs based on Annualized Revenues		$1,029.42 per month	$2.025032 per kW	$0.010326 per kWh	$0.016596 per kWh	$1.789661 per kW	$0.000000 per kW	$0.007946 per kWh

PART C

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
14	Fully Adjusted Rate Revenue Adjustment	$2,783,416							
15	Allocated on NOI Ratio (Ln 3)	$2,783,416	$1,136	$629,913	$1,037,464	$1,667,377	$824,089	$0	$290,814
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$22,022,655	$13,258	$4,626,955	$7,620,569	$12,247,523	$4,302,172	$0	$5,459,702
17	Fully Adjusted Billing Units		12	2,265,143	731,597,816	731,597,816	2,265,143	2,265,143	731,597,816
18	Unit Costs based on Fully Adjusted Cost of Service		$1,104.82 per month	$2.042677 per kW	$0.010416 per kWh	$0.016741 per kWh	$1.899294 per kW	$0.000000 per kW	$0.007463 per kWh

PART D

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
19	Proposed Rate Revenue Adjustment	$4,460,689							
20	Allocated on NOI Ratio (Ln 3)	$4,460,689	$1,820	$1,009,496	$1,662,635	$2,672,130	$1,320,681	$0	$466,058
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$26,483,344	$15,078	$5,636,450	$9,283,203	$14,919,654	$5,622,852	$0	$5,925,760
22	Fully Adjusted Billing Units		12	2,265,143	731,597,816	731,597,816	2,265,143	2,265,143	731,597,816
23	Unit Costs based on Proposed Revenue Requirement		$1,256.50 per month	$2.488342 per kW	$0.012689 per kWh	$0.020393 per kWh	$2.482339 per kW	$0.000000 per kW	$0.008100 per kWh

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 62.2213%
Demand 37.7787%

		Total	Customer	Demand - Production Demand	Demand - Production Energy	Demand - Production Combined	Demand - Transmission	Demand - Distribution	Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$21,960,946	$13,810	$2,140,345	$3,525,136	$5,665,481	$2,031,527	$2,056,295	$12,193,833
2	NOI (COS Sch 1, Ln 36)	$4,117,110	$3,272	$801,243	$1,319,643	$2,120,886	$1,045,452	$639,046	$308,454
3	NOI Ratio (Based on Ln 1)	100.0000%	0.0795%	19.4613%	32.0526%	51.5139%	25.3929%	15.5217%	7.4920%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($10,169,761)							($10,169,761)
5	Removal of Rider Revenues (on NOI Ratio)	($223)	($0)	($43)	($72)	($115)	($57)	($35)	($17)
6	Removal of Facilities Charges (on NOI Ratio)	($222,433)	($177)	($43,288)	($71,296)	($114,584)	($56,482)	($34,525)	($16,665)
7	Removal of Load Management (assigned to production)	$5		$2	$3	$5			
8	COS Per Books Base Rate Revenue	$11,568,534	$13,634	$2,097,015	$3,453,772	$5,550,787	$1,974,988	$2,021,735	$2,007,391

PART B

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

		Total	Customer	Demand - Production Demand	Demand - Production Energy	Demand - Production Combined	Demand - Transmission	Demand - Distribution	Energy
9	Annualized Rate Revenue Adjustment	($1,984,819)							
10	Allocated on NOI Ratio (Ln 3)	($1,984,819)	($1,577)	($386,272)	($636,187)	($1,022,458)	($504,002)	($308,078)	($148,703)
11	Total Revenues (Ln 8 + Ln 10)	$9,583,715	$12,056	$1,710,743	$2,817,585	$4,528,328	$1,470,985	$1,713,657	$1,858,688
12	Annualized Billing Units		36	96,466,999	159,019,895	255,486,894	636,467	636,467	255,486,894
13	Unit Costs based on Annualized Revenues		$334.89 per month	$0.017734 per kWh	$0.017718 per kWh	$0.017724 per kWh	$2.311173 per kW	$2.692453 per kW	$0.007275 per kWh

PART C

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

		Total	Customer	Demand - Production Demand	Demand - Production Energy	Demand - Production Combined	Demand - Transmission	Demand - Distribution	Energy
14	Fully Adjusted Rate Revenue Adjustment	($1,743,878)							
15	Allocated on NOI Ratio (Ln 3)	($1,743,878)	($1,386)	($339,381)	($558,959)	($898,341)	($442,821)	($270,680)	($130,652)
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$9,824,655	$12,248	$1,757,634	$2,894,812	$4,652,446	$1,532,167	$1,751,055	$1,876,739
17	Fully Adjusted Billing Units		36	98,893,555	163,019,923	261,913,478	652,477	652,477	261,913,478
18	Unit Costs based on Fully Adjusted Cost of Service		$340.21 per month	$0.017773 per kWh	$0.017757 per kWh	$0.017763 per kWh	$2.348231 per kW	$2.683704 per kW	$0.007165 per kWh

PART D

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

		Total	Customer	Demand - Production Demand	Demand - Production Energy	Demand - Production Combined	Demand - Transmission	Demand - Distribution	Energy
19	Proposed Rate Revenue Adjustment	$1,990,617							
20	Allocated on NOI Ratio (Ln 3)	$1,990,617	$1,582	$387,400	$638,046	$1,025,446	$505,475	$308,978	$149,137
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$11,815,273	$13,830	$2,145,034	$3,532,858	$5,677,892	$2,037,642	$2,060,033	$2,025,877
22	Fully Adjusted Billing Units		36	98,893,555	163,019,923	261,913,478	652,477	652,477	261,913,478
23	Unit Costs based on Proposed Revenue Requirement		$384.16 per month	$0.021690 per kWh	$0.021671 per kWh	$0.021679 per kWh	$3.122933 per kW	$3.157250 per kW	$0.007735 per kWh

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 62.2213%
Demand 37.7787%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$6,091,377	$4,588,879	$81,809	$134,738	$216,547	$58,731	$162,758	$1,064,461
2	NOI (COS Sch 1, Ln 36)	$387,896	$323,904	$10,416	$17,156	$27,572	$14,025	$16,149	$6,247
3	NOI Ratio (Based on Ln 1)	100.0000%	83.5027%	2.6853%	4.4227%	7.1080%	3.6157%	4.1631%	1.6105%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($913,313)							($913,313)
5	Removal of Rider Revenues (on NOI Ratio)	$0	$0	$0	$0	$0	$0	$0	$0
6	Removal of Facilities Charges (on NOI Ratio)	$0	$0	$0	$0	$0	$0	$0	$0
7	Removal of Load Management (assigned to production)	$0		$0	$0	$0			
8	COS Per Books Base Rate Revenue	$5,178,064	$4,588,879	$81,809	$134,738	$216,547	$58,731	$162,758	$151,148

PART B

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
9	Annualized Rate Revenue Adjustment	($21,320)							
10	Allocated on NOI Ratio (Ln 3)	($21,320)	($17,803)	($572)	($943)	($1,515)	($771)	($888)	($343)
11	Total Revenues (Ln 8 + Ln 10)	$5,156,744	$4,571,076	$81,237	$133,795	$215,032	$57,960	$161,871	$150,805
12	Annualized Billing Units		347,796	21,480,264	21,480,264	21,480,264	21,480,264	21,480,264	21,480,264
13	Unit Costs based on Annualized Revenues		$13.14 per month	$0.003782 per kWh	$0.006229 per kWh	$0.010011 per kWh	$0.002698 per kWh	$0.007536 per kWh	$0.007021 per kWh

PART C

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
14	Fully Adjusted Rate Revenue Adjustment	$72,663							
15	Allocated on NOI Ratio (Ln 3)	$72,663	$60,676	$1,951	$3,214	$5,165	$2,627	$3,025	$1,170
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$5,250,727	$4,649,555	$83,760	$137,952	$221,712	$61,358	$165,783	$152,318
17	Fully Adjusted Billing Units		318,276	19,657,087	19,657,087	19,657,087	19,657,087	19,657,087	19,657,087
18	Unit Costs based on Fully Adjusted Cost of Service		$14.61 per month	$0.004261 per kWh	$0.007018 per kWh	$0.011279 per kWh	$0.003121 per kWh	$0.008434 per kWh	$0.007749 per kWh

PART D

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
19	Proposed Rate Revenue Adjustment	$2,067,260							
20	Allocated on NOI Ratio (Ln 3)	$2,067,260	$1,726,219	$55,511	$91,430	$146,941	$74,745	$86,063	$33,293
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$7,317,988	$6,375,774	$139,272	$229,381	$368,653	$136,103	$251,846	$185,611
22	Fully Adjusted Billing Units		318,276	19,657,087	19,657,087	19,657,087	19,657,087	19,657,087	19,657,087
23	Unit Costs based on Proposed Revenue Requirement		$20.03 per month	$0.007085 per kWh	$0.011669 per kWh	$0.018754 per kWh	$0.006924 per kWh	$0.012812 per kWh	$0.009442 per kWh

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 62.2213%
Demand 37.7787%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$67,604	$33,975	$3,323	$5,473	$8,796	$3,047	$2,406	$19,380
2	NOI (COS Sch 1, Ln 36)	$10,904	$5,270	$1,170	$1,928	$3,098	$1,494	$703	$338
3	NOI Ratio (Based on Ln 1)	100.0000%	48.3312%	10.7301%	17.6786%	28.4087%	13.7054%	6.4517%	3.1030%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($16,290)							($16,290)
5	Removal of Rider Revenues (on NOI Ratio)	$0	$0	$0	$0	$0	$0	$0	$0
6	Removal of Facilities Charges (on NOI Ratio)	$0	$0	$0	$0	$0	$0	$0	$0
7	Removal of Load Management (assigned to production)	$0		$0	$0	$0			
8	COS Per Books Base Rate Revenue	$51,314	$33,975	$3,323	$5,473	$8,796	$3,047	$2,406	$3,090

PART B

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
9	Annualized Rate Revenue Adjustment	($3,110)							
10	Allocated on NOI Ratio (Ln 3)	($3,110)	($1,503)	($334)	($550)	($883)	($426)	($201)	($96)
11	Total Revenues (Ln 8 + Ln 10)	$48,204	$32,472	$2,989	$4,923	$7,912	$2,620	$2,206	$2,994
12	Annualized Billing Units		2,340	465,629	465,629	465,629	465,629	465,629	465,629
13	Unit Costs based on Annualized Revenues		$13.88 per month	$0.006420 per kWh	$0.010572 per kWh	$0.016992 per kWh	$0.005628 per kWh	$0.004737 per kWh	$0.006429 per kWh

PART C

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
14	Fully Adjusted Rate Revenue Adjustment	($352)							
15	Allocated on NOI Ratio (Ln 3)	($352)	($170)	($38)	($62)	($100)	($48)	($23)	($11)
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$50,962	$33,805	$3,285	$5,410	$8,696	$2,998	$2,384	$3,079
17	Fully Adjusted Billing Units		2,352	513,499	513,499	513,499	513,499	513,499	513,499
18	Unit Costs based on Fully Adjusted Cost of Service		$14.37 per month	$0.006398 per kWh	$0.010536 per kWh	$0.016934 per kWh	$0.005839 per kWh	$0.004642 per kWh	$0.005997 per kWh

PART D

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
19	Proposed Rate Revenue Adjustment	$11,468							
20	Allocated on NOI Ratio (Ln 3)	$11,468	$5,543	$1,231	$2,027	$3,258	$1,572	$740	$356
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$62,430	$39,347	$4,516	$7,438	$11,953	$4,570	$3,124	$3,435
22	Fully Adjusted Billing Units		2,352	513,499	513,499	513,499	513,499	513,499	513,499
23	Unit Costs based on Proposed Revenue Requirement		$16.73 per month	$0.008794 per kWh	$0.014484 per kWh	$0.023278 per kWh	$0.008900 per kWh	$0.006083 per kWh	$0.006690 per kWh

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023

SCHEDULE 1

SCHEDULE 1 - SUMMARY

Line #		NC Jur Total	Residential	SGS,CO & Muni	LGS	Schedule NS	6VP	St & Outdoor Lighting	Traffic Lighting	Allocation Basis
1	Dec 2023									
2										
3	C:[SUMMARY OF RESULTS]									
4	D:[]									
5	E:[OPERATING REVENUES]	408,196,365	195,434,718	82,958,619	53,543,969	47,791,492	22,166,496	6,231,951	69,121	NC Class Schedule 2 - Revenue/Lir
6	F:[]									
7	G:[OPERATING EXPENSES]									
8	H:[OPERATION & MAINTENANCE EXPENSES]	239,139,128	108,998,929	48,458,206	31,074,334	33,349,582	13,823,736	3,391,636	42,705	NC Class Schedule 3 - O&M Expen
9	I:[DEPRECIATION EXPENSE]	60,832,913	37,664,335	12,176,190	4,893,329	1,809,067	2,126,311	2,152,423	11,259	NC Class Schedule 4 - Depreciatio
10	J:[AMORT. OF ACQ. AJUSTMENTS]	7,311	4,437	1,484	706	363	321	0	1	NC Class Schedule 4 - Depreciatio
11	K:[AMORT. OF PROP. LOSS & REG STUDY]	83,583	50,728	16,959	8,069	4,153	3,667	0	7	NC Class Schedule 6 - Net Current
12	L:[REGULATORY DEBITS AND CREDITS]	10,909,089	5,716,690	2,179,543	1,280,604	1,127,382	577,891	25,988	990	NC Class Schedule 6 - Net Current
13	N:[GAIN/LOSS ON DISPOSITION OF ALLOWANCES]	(89,091)	(35,475)	(17,379)	(13,278)	(16,464)	(5,951)	(534)	(10)	NC Class Schedule 6 - Net Current
14	O:[GAIN / LOSS ON DISPOSITION OF PROPERTY]	245,242	150,199	49,489	21,096	9,094	9,237	6,089	38	NC Class Schedule 6 - Net Current
15	Q:[ACCRETION EXPENSE - ARO]	5,133,919	2,218,047	1,008,257	721,831	836,954	324,018	24,220	591	NC Class Schedule 22 - Other Alloc
16	R:[FEDERAL INCOME TAX]									
17	S:[INVESTMENT TAX CREDIT - AMORTIZATION]	141,040	85,600	28,618	13,616	7,008	6,187	0	11	NC Class Schedule 7 - Income Tax
18	T:[FEDERAL NET CURRENT TAX]	6,833,874	(810,010)	1,419,843	2,620,647	2,905,916	836,736	(140,218)	961	NC Class Schedule 6 - Net Current
19	U:[FEDERAL INCOME TAX DEFERRED]	(3,208,237)	(159,343)	(587,905)	(785,722)	(1,288,508)	(341,932)	(44,401)	(425)	NC Class Schedule 7 - Income Tax
20	W:[STATE INCOME TAX CURRENT]	483,103	98,179	103,713	137,286	108,852	40,434	(5,433)	73	NC Class Schedule 6 - Net Current
21	X:[STATE INCOME TAX DEFERRED]	1,812,324	368,311	389,072	515,017	408,350	151,684	(20,383)	273	NC Class Schedule 7 - Income Tax
22	Y:[TAXES OTHER THAN INCOME TAX]	12,635,649	7,830,775	2,563,679	1,057,939	402,594	462,558	315,941	2,163	NC Class Schedule 5 - Other Taxes
23	Z:[TOTAL ELECTRIC OPERATING EXPENSES]	334,959,847	162,181,404	67,789,769	41,545,475	39,664,341	18,014,895	5,705,326	58,638	
24	AA:[]									
25	AB:[NET OPERATING INCOME]	73,236,518	33,253,314	15,168,850	11,998,494	8,127,151	4,151,601	526,624	10,483	
26	AC:[]									
27	AD:[ADJUSTMENTS TO OPERATING INCOME]									
28	AE:[ADD: ALLOWANCE FOR FUNDS]	14,108,009	8,533,710	2,860,317	1,357,539	707,215	614,820	33,189	1,217	NC Class Schedule 8 - Other Adjus
29	AF:[]									
30	AG:[DEDUCT: CHARITABLE & EDUCATIONAL]									
31	AH:[DONATIONS]	397,631	181,239	80,574	51,669	55,452	22,986	5,639	71	NC Class Schedule 8 - Other Adjus
32	AI:[DONATIONS - ASSIGNED]	0	0	0	0	0	0	0	0	NC Class Schedule 8 - Other Adjus
33	AJ:[INTEREST EXPENSE - CUST. DEPOSITS]	31,017	14,826	6,309	4,080	3,641	1,688	468	5	NC Class Schedule 8 - Other Adjus
34	AK:[OTHER INTEREST EXPENSE]	212,619	129,303	43,059	18,843	8,478	8,445	4,459	31	NC Class Schedule 8 - Other Adjus
35	AL:[TOTAL DEDUCTIONS]	641,268	325,368	129,943	74,592	67,572	33,119	10,567	107	
36	AM:[]									
37	AN:[ADJUSTED NET ELEC. OPERATING INCOME]	86,703,259	41,461,656	17,899,224	13,281,441	8,766,795	4,733,302	549,247	11,593	
38	AO:[]									
39	AP:[RATE BASE]	1,594,851,513	958,109,730	323,025,980	144,937,388	71,029,787	65,056,712	32,464,902	227,014	NC Class Schedule 1 - Summary/Li
40	AQ:[]									
41	AR:[ROR EARNED ON RATE BASE (Including Ringfenced as applic	5.4364%	4.3274%	5.5411%	9.1636%	12.3424%	7.2757%	1.6918%	5.1068%	
42	AS:[]									
43	AV:[SYSTEM RATE OF RETURN (Excluding Ringfenced as applicat	5.4364%	5.4364%	5.4364%	5.4364%	5.4364%	5.4364%	5.4364%	5.4364%	
44	AW:[INDEX RATE OF RETURN (PRESENT) (AQ/AU)]	1.00	0.80	1.02	1.69	2.27	1.34	0.31	0.94	
45	AX:[]									

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023

SCHEDULE 1

SCHEDULE 1 - SUMMARY

Line #		NC Jur Total	Residential	SGS,CO & Muni	LGS	Schedule NS	6VP	St & Outdoor Lighting	Traffic Lighting	Allocation Basis
46	AY:[]									
47	AZ:[]									
48	BA:[RATE BASE]									
49	BB:[PLANT INVESTMENT]									
50	BC:[ELECTRIC PLANT INCL. NUCLEAR FUEL]	2,269,147,992	1,389,748,037	457,908,299	195,196,772	84,139,751	85,465,990	56,336,264	352,878	NC Class Schedule 10 - Plant in Ser
51	BD:[ACQUISITION ADJUSTMENTS]	313,057	190,001	63,521	30,223	15,555	13,733	0	25	NC Class Schedule 10 - Plant in Ser
52	BE:[ELECTRIC CWIP INCL FUEL]	360,345,332	212,789,477	72,650,467	35,680,137	21,040,184	15,909,270	2,240,601	35,196	NC Class Schedule 12 - Constructic
53	BF:[PLANT HELD FOR FUTURE USE]	0	0	0	0	0	0	0	0	NC Class Schedule 13 - Plant Held f
54	BG:[TOTAL PLANT INVESTMENT]	2,629,806,381	1,602,727,514	530,622,287	230,907,132	105,195,491	101,388,993	58,576,865	388,099	
55	BH:[]									
56	BI:[DEDUCT:]									
57	BJ:[ACCUM. PROV. FOR DEPREC. & AMORT]	(778,067,179)	(488,297,438)	(156,024,643)	(63,440,119)	(23,288,551)	(26,330,632)	(20,567,727)	(118,071)	NC Class Schedule 11 - Accum Dep
58	BK:[AMORT OF NUCLEAR FUEL]	(55,694,591)	(22,176,751)	(10,864,121)	(8,300,666)	(10,292,639)	(3,720,343)	(334,112)	(5,959)	NC Class Schedule 11 - Accum Dep
59	BL:[ACQUISITION ADJ. FOR DEPREC. RESERVE]	(53,457)	(32,444)	(10,847)	(5,161)	(2,656)	(2,345)	0	(4)	NC Class Schedule 11 - Accum Dep
60	BM:[TOTAL DEPRECIATION & AMORTIZATION]	(833,815,226)	(510,506,632)	(166,899,611)	(71,745,946)	(33,583,846)	(30,053,320)	(20,901,838)	(124,034)	
61	BN:[]									
62	BO:[NET PLANT]	1,795,991,155	1,092,220,882	363,722,676	159,161,187	71,611,645	71,335,673	37,675,026	264,065	
63	BP:[]									
64	BQ:[DEDUCT:]									
65	BS:[ACCUMULATED DEFERRED INCOME TAXES]	185,445,996	102,903,803	37,069,533	19,106,923	14,294,421	8,475,387	3,569,714	26,216	NC Class Schedule 23 - Cost Free C
67	BW:[CUSTOMER DEPOSITS]	3,135,948	1,498,955	637,850	412,511	368,147	170,631	47,328	525	NC Class Schedule 14 - Working Ca
68	BX:[EXCESS DEFERRED INCOME TAXES]	107,582,689	66,602,191	21,776,576	9,103,890	3,500,808	3,988,818	2,594,872	15,533	NC Class Schedule 23 - Cost Free C
69	BY:[]									
70	BZ:[ADD: WORKING CAPITAL]									
71	CA:[MATERIAL & SUPPLIES]	50,733,308	27,375,595	10,142,546	5,526,099	4,487,694	2,458,505	736,690	6,180	NC Class Schedule 14 - Working Ca
73	CC:[INVESTOR FUNDS ADVANCED]	15,791,563	7,560,289	3,209,504	2,071,572	1,848,587	857,457	241,476	2,676	NC Class Schedule 14 - Working Ca
74	CD:[TOTAL ADDITIONS]	264,540,117	118,379,886	52,076,774	35,972,717	40,274,433	16,132,229	1,675,847	28,231	NC Class Schedule 14 - Working Ca
78	CH:[TOTAL DEDUCTIONS]	(236,039,996)	(116,421,974)	(46,641,561)	(29,170,862)	(29,029,195)	(13,092,317)	(1,652,223)	(31,864)	NC Class Schedule 14 - Working Ca
80	CJ:[DEFERRED FUEL]	0	0	0	0	0	0	0	0	NC Class Schedule 14 - Working Ca
82	CL:[TOTAL ALLOWANCE FOR WORK CAPITAL]	95,024,991	36,893,796	18,787,264	14,399,526	17,581,519	6,355,874	1,001,790	5,223	
83	CM:[]									
84	CN:[TOTAL RATE BASE]	1,594,851,513	958,109,730	323,025,980	144,937,388	71,029,787	65,056,712	32,464,902	227,014	
85	CO:[]									

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**Residential Class** **Annualized Cost of Service Summary** DESCRIPTION	(1) Residential Cost of Service	(2) Annualized Revenue Adjustment	(3) Residential Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$129,458,147	$2,966,963	$132,425,110
2	Forfeited Discounts and Miscellaneous Service Revenues	$761,746	$27,665	$789,410
3	Non-Fuel Rider Revenues	$2,842,691	$0	$2,842,691
4	Fuel Revenues	$60,621,360	$0	$60,621,360
5	Other Operating Revenues	$1,750,775	$0	$1,750,775
6	TOTAL OPERATING REVENUES	$195,434,718	$2,994,628	$198,429,346
	OPERATING EXPENSES			
7	Fuel Expense	$61,522,679		$61,522,679
8	Non-Fuel Operating and Maintenance Expense	$47,476,250	$21,810	$47,498,060
9	Depreciation and Amortization	$45,654,239		$45,654,239
10	Federal Income Tax	($883,753)	$587,435	($296,318)
11	State Income Tax	$466,490	$171,121	$637,611
12	Taxes Other than Income Tax	$7,830,775	$4,385	$7,835,160
13	(Gain)/Loss on Disposition of Property	$114,725		$114,725
14	TOTAL ELECTRIC OPERATING EXPENSES	$162,181,405	$784,751	$162,966,156
15	**NET OPERATING INCOME**	$33,253,313	$2,209,876	$35,463,189
	ADJUSTMENTS TO OPERATING INCOME			
16	*ADD:* AFUDC	$8,533,710		$8,533,710
17	*LESS:* Charitable Donations	$181,239		$181,239
18	Interest Expense on Customer Deposits	$14,826		$14,826
19	Other Interest Expense/(Income)	$129,303		$129,303
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$41,461,655	$2,209,876	$43,671,531
21	**RATE BASE (from Line 38 below)**	$958,109,729	$0	$958,109,729
22	**ROR EARNED ON AVERAGE RATE BASE**	4.3274%		4.5581%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$27,375,595		$27,375,595
24	Investor Funds Advanced	$7,560,289		$7,560,289
25	Total Additions	$118,379,886		$118,379,886
26	Total Deductions	($116,421,974)		($116,421,974)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$36,893,796	$0	$36,893,796
	NET UTILITY PLANT			
28	Utility Plant in Service	$1,389,748,037		$1,389,748,037
29	Acquisition Adjustments	$190,001		$190,001
30	Construction Work in Progress	$212,789,477		$212,789,477
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$510,474,189		$510,474,189
32	Provision for Acquisition Adjustments	$32,444		$32,444
33	TOTAL NET UTILITY PLANT	$1,092,220,882	$0	$1,092,220,882
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$1,498,955		$1,498,955
35	Accumulated Deferred Income Taxes	$102,903,803		$102,903,803
36	Other Cost Free Capital	$66,602,191		$66,602,191
37	TOTAL RATE BASE DEDUCTIONS	$171,004,949	$0	$171,004,949
38	**TOTAL RATE BASE**	$958,109,729	$0	$958,109,729

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**SGS & Public Authorities Class** **Annualized Cost of Service Summary** DESCRIPTION	(1) SGS Cost of Service	(2) Annualized Revenue Adjustment	(3) SGS Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$51,071,053	($989,314)	$50,081,739
2	Forfeited Discounts and Miscellaneous Service Revenues	$210,233	$9,925	$220,158
3	Non-Fuel Rider Revenues	$1,325,418	$0	
4	Fuel Revenues	$29,697,669	$0	$29,697,669
5	Other Operating Revenues	$654,247	$0	$654,247
6	TOTAL OPERATING REVENUES	$82,958,619	($979,389)	$81,979,230
	OPERATING EXPENSES			
7	Fuel Expense	$30,139,214		$30,139,214
8	Non-Fuel Operating and Maintenance Expense	$18,318,992	($7,133)	$18,311,859
9	Depreciation and Amortization	$15,382,433		$15,382,433
10	Federal Income Tax	$860,556	($192,120)	$668,436
11	State Income Tax	$492,785	($55,965)	$436,820
12	Taxes Other than Income Tax	$2,563,679	($1,434)	$2,562,245
13	(Gain)/Loss on Disposition of Property	$32,111		$32,111
14	TOTAL ELECTRIC OPERATING EXPENSES	$67,789,770	($256,652)	$67,533,118
15	**NET OPERATING INCOME**	$15,168,849	($722,737)	$14,446,112
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$2,860,317		$2,860,317
17	LESS: Charitable Donations	$80,574		$80,574
18	Interest Expense on Customer Deposits	$6,309		$6,309
19	Other Interest Expense/(Income)	$43,059		$43,059
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$17,899,224	($722,737)	$17,176,487
21	**RATE BASE (from Line 38 below)**	$323,025,980	$0	$323,025,980
22	**ROR EARNED ON AVERAGE RATE BASE**	5.5411%		5.3174%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$10,142,546		$10,142,546
24	Investor Funds Advanced	$3,209,504		$3,209,504
25	Total Additions	$52,076,774		$52,076,774
26	Total Deductions	($46,641,561)		($46,641,561)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$18,787,263	$0	$18,787,263
	NET UTILITY PLANT			
28	Utility Plant in Service	$457,908,299		$457,908,299
29	Acquisition Adjustments	$63,521		$63,521
30	Construction Work in Progress	$72,650,467		$72,650,467
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$166,888,764		$166,888,764
32	Provision for Acquisition Adjustments	$10,847		$10,847
33	TOTAL NET UTILITY PLANT	$363,722,676	$0	$363,722,676
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$637,850		$637,850
35	Accumulated Deferred Income Taxes	$37,069,533		$37,069,533
36	Other Cost Free Capital	$21,776,576		$21,776,576
37	TOTAL RATE BASE DEDUCTIONS	$59,483,959	$0	$59,483,959
38	**TOTAL RATE BASE**	$323,025,980	$0	$323,025,980

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**LGS Class** **Annualized Cost of Service Summary** DESCRIPTION	(1) LGS Cost of Service	(2) Annualized Revenue Adjustment	(3) LGS Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$29,965,630	($3,799,661)	$26,165,969
2	Forfeited Discounts and Miscellaneous Service Revenues	$88,823	$5,654	$94,477
3	Non-Fuel Rider Revenues	$436,077	$0	
4	Fuel Revenues	$22,690,325	$0	$22,690,325
5	Other Operating Revenues	$363,114	$0	$363,114
6	TOTAL OPERATING REVENUES	$53,543,969	($3,794,007)	$49,749,962
	OPERATING EXPENSES			
7	Fuel Expense	$23,027,685		$23,027,685
8	Non-Fuel Operating and Maintenance Expense	$8,046,649	($27,632)	$8,019,017
9	Depreciation and Amortization	$6,904,539		$6,904,539
10	Federal Income Tax	$1,848,541	($744,244)	$1,104,297
11	State Income Tax	$652,303	($216,799)	$435,504
12	Taxes Other than Income Tax	$1,057,939	($5,555)	$1,052,384
13	(Gain)/Loss on Disposition of Property	$7,818		$7,818
14	TOTAL ELECTRIC OPERATING EXPENSES	$41,545,474	($994,231)	$40,551,243
15	**NET OPERATING INCOME**	$11,998,495	($2,799,775)	$9,198,719
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$1,357,539		$1,357,539
17	LESS: Charitable Donations	$51,669		$51,669
18	Interest Expense on Customer Deposits	$4,080		$4,080
19	Other Interest Expense/(Income)	$18,843		$18,843
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$13,281,442	($2,799,775)	$10,481,666
21	**RATE BASE (from Line 38 below)**	$144,937,388	$0	$144,937,388
22	**ROR EARNED ON AVERAGE RATE BASE**	9.1636%		7.2319%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$5,526,099		$5,526,099
24	Investor Funds Advanced	$2,071,572		$2,071,572
25	Total Additions	$35,972,717		$35,972,717
26	Total Deductions	($29,170,862)		($29,170,862)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$14,399,526	$0	$14,399,526
	NET UTILITY PLANT			
28	Utility Plant in Service	$195,196,772		$195,196,772
29	Acquisition Adjustments	$30,223		$30,223
30	Construction Work in Progress	$35,680,137		$35,680,137
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$71,740,785		$71,740,785
32	Provision for Acquisition Adjustments	$5,161		$5,161
33	TOTAL NET UTILITY PLANT	$159,161,186	$0	$159,161,186
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$412,511		$412,511
35	Accumulated Deferred Income Taxes	$19,106,923		$19,106,923
36	Other Cost Free Capital	$9,103,890		$9,103,890
37	TOTAL RATE BASE DEDUCTIONS	$28,623,324	$0	$28,623,324
38	**TOTAL RATE BASE**	$144,937,388	$0	$144,937,388

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

Schedule NS Class
Annualized Cost of Service Summary

LINE NO.	DESCRIPTION	(1) Sched NS Cost of Service	(2) Annualized Revenue Adjustment	(3) Sched NS Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load			
1	Management	$19,246,714	$562,158	$19,808,872
2	Forfeited Discounts and Miscellaneous Service Revenues	$79,098	$5,043	$84,142
3	Non-Fuel Rider Revenues	$0	$0	
4	Fuel Revenues	$28,135,491	$0	$28,135,491
5	Other Operating Revenues	$330,189	$0	$330,189
6	TOTAL OPERATING REVENUES	$47,791,492	$567,201	$48,358,694
	OPERATING EXPENSES			
7	Fuel Expense	$28,553,810		$28,553,810
8	Non-Fuel Operating and Maintenance Expense	$4,795,772	$4,131	$4,799,903
9	Depreciation and Amortization	$3,777,919		$3,777,919
10	Federal Income Tax	$1,624,415	$111,264	$1,735,679
11	State Income Tax	$517,201	$32,411	$549,612
12	Taxes Other than Income Tax	$402,594	$831	$403,425
13	(Gain)/Loss on Disposition of Property	($7,371)		($7,371)
14	TOTAL ELECTRIC OPERATING EXPENSES	$39,664,340	$148,637	$39,812,977
15	**NET OPERATING INCOME**	$8,127,152	$418,564	$8,545,717
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$707,215		$707,215
17	LESS: Charitable Donations	$55,452		$55,452
18	Interest Expense on Customer Deposits	$3,641		$3,641
19	Other Interest Expense/(Income)	$8,478		$8,478
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$8,766,796	$418,564	$9,185,361
21	**RATE BASE (from Line 38 below)**	$71,029,788	$0	$71,029,788
22	**ROR EARNED ON AVERAGE RATE BASE**	12.3424%		12.9317%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$4,487,694		$4,487,694
24	Investor Funds Advanced	$1,848,587		$1,848,587
25	Total Additions	$40,274,433		$40,274,433
26	Total Deductions	($29,029,195)		($29,029,195)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$17,581,519	$0	$17,581,519
	NET UTILITY PLANT			
28	Utility Plant in Service	$84,139,751		$84,139,751
29	Acquisition Adjustments	$15,555		$15,555
30	Construction Work in Progress	$21,040,184		$21,040,184
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$33,581,189		$33,581,189
32	Provision for Acquisition Adjustments	$2,656		$2,656
33	TOTAL NET UTILITY PLANT	$71,611,645	$0	$71,611,645
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$368,147		$368,147
35	Accumulated Deferred Income Taxes	$14,294,421		$14,294,421
36	Other Cost Free Capital	$3,500,808		$3,500,808
37	TOTAL RATE BASE DEDUCTIONS	$18,163,376	$0	$18,163,376
38	**TOTAL RATE BASE**	$71,029,788	$0	$71,029,788

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**6VP Class** **Annualized Cost of Service Summary** DESCRIPTION	(1) 6VP Cost of Service	(2) Annualized Revenue Adjustment	(3) 6VP Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load			
1	Management	$11,790,963	($1,986,925)	$9,804,038
2	Forfeited Discounts and Miscellaneous Service Revenues	$36,671	$2,338	$39,009
3	Non-Fuel Rider Revenues	$223	$0	
4	Fuel Revenues	$10,169,761	$0	$10,169,761
5	Other Operating Revenues	$168,877	$0	$168,877
6	TOTAL OPERATING REVENUES	$22,166,496	($1,984,588)	$20,181,908
	OPERATING EXPENSES			
7	Fuel Expense	$10,320,965		$10,320,965
8	Non-Fuel Operating and Maintenance Expense	$3,502,771	($14,454)	$3,488,317
9	Depreciation and Amortization	$3,032,207		$3,032,207
10	Federal Income Tax	$500,991	($389,303)	$111,688
11	State Income Tax	$192,118	($113,404)	$78,714
12	Taxes Other than Income Tax	$462,558	($2,906)	$459,652
13	(Gain)/Loss on Disposition of Property	$3,286		$3,286
14	TOTAL ELECTRIC OPERATING EXPENSES	$18,014,896	($520,067)	$17,494,829
15	**NET OPERATING INCOME**	$4,151,600	($1,464,520)	$2,687,079
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$614,820		$614,820
17	LESS: Charitable Donations	$22,986		$22,986
18	Interest Expense on Customer Deposits	$1,688		$1,688
19	Other Interest Expense/(Income)	$8,445		$8,445
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$4,733,301	($1,464,520)	$3,268,780
21	**RATE BASE (from Line 38 below)**	$65,056,711	$0	$65,056,711
22	**ROR EARNED ON AVERAGE RATE BASE**	7.2757%		5.0245%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$2,458,505		$2,458,505
24	Investor Funds Advanced	$857,457		$857,457
25	Total Additions	$16,132,229		$16,132,229
26	Total Deductions	($13,092,317)		($13,092,317)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$6,355,874	$0	$6,355,874
	NET UTILITY PLANT			
28	Utility Plant in Service	$85,465,990		$85,465,990
29	Acquisition Adjustments	$13,733		$13,733
30	Construction Work in Progress	$15,909,270		$15,909,270
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$30,050,975		$30,050,975
32	Provision for Acquisition Adjustments	$2,345		$2,345
33	TOTAL NET UTILITY PLANT	$71,335,673	$0	$71,335,673
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$170,631		$170,631
35	Accumulated Deferred Income Taxes	$8,475,387		$8,475,387
36	Other Cost Free Capital	$3,988,818		$3,988,818
37	TOTAL RATE BASE DEDUCTIONS	$12,634,836	$0	$12,634,836
38	**TOTAL RATE BASE**	$65,056,711	$0	$65,056,711

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

Street and Outdoor Lighting Class
Annualized Cost of Service Summary

LINE NO.	DESCRIPTION	(1) Street & Outdoor Lighting Cost of Service	(2) Annualized Revenue Adjustment	(3) Street & Outdoor Lighting COS Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$5,178,064	($21,564)	$5,156,500
2	Forfeited Discounts and Miscellaneous Service Revenues	$76,019	$1,716	$77,735
3	Non-Fuel Rider Revenues	$0	$0	
4	Fuel Revenues	$913,313	$0	$913,313
5	Other Operating Revenues	$64,555	$0	$64,555
6	TOTAL OPERATING REVENUES	$6,231,951	($19,848)	$6,212,102
	OPERATING EXPENSES			
7	Fuel Expense	$926,892		$926,892
8	Non-Fuel Operating and Maintenance Expense	$2,464,744	($145)	$2,464,599
9	Depreciation and Amortization	$2,202,631		$2,202,631
10	Federal Income Tax	($184,619)	($3,893)	($188,512)
11	State Income Tax	($25,817)	($1,134)	($26,951)
12	Taxes Other than Income Tax	$315,941	($29)	$315,912
13	(Gain)/Loss on Disposition of Property	$5,554		$5,554
14	TOTAL ELECTRIC OPERATING EXPENSES	$5,705,326	($5,201)	$5,700,125
15	**NET OPERATING INCOME**	$526,625	($14,647)	$511,978
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$33,189		$33,189
17	LESS: Charitable Donations	$5,639		$5,639
18	Interest Expense on Customer Deposits	$468		$468
19	Other Interest Expense/(Income)	$4,459		$4,459
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$549,248	($14,647)	$534,601
21	**RATE BASE (from Line 38 below)**	$32,464,903	$0	$32,464,903
22	**ROR EARNED ON AVERAGE RATE BASE**	1.6918%		1.6467%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$736,690		$736,690
24	Investor Funds Advanced	$241,476		$241,476
25	Total Additions	$1,675,847		$1,675,847
26	Total Deductions	($1,652,223)		($1,652,223)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$1,001,790	$0	$1,001,790
	NET UTILITY PLANT			
28	Utility Plant in Service	$56,336,264		$56,336,264
29	Acquisition Adjustments	$0		$0
30	Construction Work in Progress	$2,240,601		$2,240,601
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$20,901,838		$20,901,838
32	Provision for Acquisition Adjustments	$0		$0
33	TOTAL NET UTILITY PLANT	$37,675,027	$0	$37,675,027
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$47,328		$47,328
35	Accumulated Deferred Income Taxes	$3,569,714		$3,569,714
36	Other Cost Free Capital	$2,594,872		$2,594,872
37	TOTAL RATE BASE DEDUCTIONS	$6,211,914	$0	$6,211,914
38	**TOTAL RATE BASE**	$32,464,903	$0	$32,464,903

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

Traffic Lighting Class
Annualized Cost of Service Summary

LINE NO.	DESCRIPTION	(1) Traffic Lighting Cost of Service	(2) Annualized Revenue Adjustment	(3) Traffic Lighting Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load			
1	Management	$51,314	($3,115)	$48,199
2	Forfeited Discounts and Miscellaneous Service Revenues	$899	$20	$919
3	Non-Fuel Rider Revenues	$0	$0	
4	Fuel Revenues	$16,290	$0	$16,290
5	Other Operating Revenues	$618	$0	$618
6	TOTAL OPERATING REVENUES	$69,121	($3,095)	$66,026
	OPERATING EXPENSES			
7	Fuel Expense	$16,532		$16,532
8	Non-Fuel Operating and Maintenance Expense	$26,173	($23)	$26,150
9	Depreciation and Amortization	$12,847		$12,847
10	Federal Income Tax	$547	($607)	($60)
11	State Income Tax	$346	($177)	$169
12	Taxes Other than Income Tax	$2,163	($5)	$2,158
13	(Gain)/Loss on Disposition of Property	$29		$29
14	TOTAL ELECTRIC OPERATING EXPENSES	$58,637	($811)	$57,826
15	**NET OPERATING INCOME**	$10,484	($2,284)	$8,200
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$1,217		$1,217
17	LESS: Charitable Donations	$71		$71
18	Interest Expense on Customer Deposits	$5		$5
19	Other Interest Expense/(Income)	$31		$31
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$11,594	($2,284)	$9,310
21	**RATE BASE (from Line 38 below)**	$227,014	$0	$227,014
22	**ROR EARNED ON AVERAGE RATE BASE**	5.1071%		4.1011%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$6,180		$6,180
24	Investor Funds Advanced	$2,676		$2,676
25	Total Additions	$28,231		$28,231
26	Total Deductions	($31,864)		($31,864)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$5,223	$0	$5,223
	NET UTILITY PLANT			
28	Utility Plant in Service	$352,878		$352,878
29	Acquisition Adjustments	$25		$25
30	Construction Work in Progress	$35,196		$35,196
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$124,030		$124,030
32	Provision for Acquisition Adjustments	$4		$4
33	TOTAL NET UTILITY PLANT	$264,065	$0	$264,065
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$525		$525
35	Accumulated Deferred Income Taxes	$26,216		$26,216
36	Other Cost Free Capital	$15,533		$15,533
37	TOTAL RATE BASE DEDUCTIONS	$42,274	$0	$42,274
38	**TOTAL RATE BASE**	$227,014	$0	$227,014

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**Total of All North Carolina Classes** **Annualized Cost of Service Summary** DESCRIPTION	(1) Total Cost of Service	(2) Annualized Revenue Adjustment	(3) Total Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$246,761,884	($3,271,458)	$243,490,427
2	Forfeited Discounts and Miscellaneous Service Revenues	$1,253,489	$52,361	$1,305,850
3	Non-Fuel Rider Revenues	$4,604,409	$0	$4,604,409
4	Fuel Revenues	$152,244,208	$0	$152,244,208
5	Other Operating Revenues	$3,332,375	$0	$3,332,375
6	TOTAL OPERATING REVENUES	$408,196,365	($3,219,097)	$404,977,268
	OPERATING EXPENSES			
7	Fuel Expense	$154,507,777	$0	$154,507,777
8	Non-Fuel Operating and Maintenance Expense	$84,631,351	($23,445)	$84,607,906
9	Depreciation and Amortization	$76,966,815	$0	$76,966,815
10	Federal Income Tax	$3,766,678	($631,468)	$3,135,210
11	State Income Tax	$2,295,426	($183,947)	$2,111,479
12	Taxes Other than Income Tax	$12,635,649	($4,714)	$12,630,935
13	(Gain)/Loss on Disposition of Property	$156,152	$0	$156,152
14	TOTAL ELECTRIC OPERATING EXPENSES	$334,959,848	($843,574)	$334,116,274
15	**NET OPERATING INCOME**	$73,236,517	($2,375,523)	$70,860,995
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$14,108,007	$0	$14,108,007
17	LESS: Charitable Donations	$397,630	$0	$397,630
18	Interest Expense on Customer Deposits	$31,017	$0	$31,017
19	Other Interest Expense/(Income)	$212,618	$0	$212,618
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$86,703,259	($2,375,523)	$84,327,737
21	**RATE BASE (from Line 38 below)**	$1,594,851,513	$0	$1,594,851,513
22	**ROR EARNED ON AVERAGE RATE BASE**	5.4364%		5.2875%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$50,733,309	$0	$50,733,309
24	Investor Funds Advanced	$15,791,561	$0	$15,791,561
25	Total Additions	$264,540,117	$0	$264,540,117
26	Total Deductions	($236,039,996)	$0	($236,039,996)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$95,024,991	$0	$95,024,991
	NET UTILITY PLANT			
28	Utility Plant in Service	$2,269,147,991	$0	$2,269,147,991
29	Acquisition Adjustments	$313,058	$0	$313,058
30	Construction Work in Progress	$360,345,332	$0	$360,345,332
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$833,761,770	$0	$833,761,770
32	Provision for Acquisition Adjustments	$53,457	$0	$53,457
33	TOTAL NET UTILITY PLANT	$1,795,991,154	$0	$1,795,991,154
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$3,135,947	$0	$3,135,947
35	Accumulated Deferred Income Taxes	$185,445,997	$0	$185,445,997
36	Other Cost Free Capital	$107,582,688	$0	$107,582,688
37	TOTAL RATE BASE DEDUCTIONS	$296,164,632	$0	$296,164,632
38	**TOTAL RATE BASE**	$1,594,851,513	$0	$1,594,851,513

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Residential Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **Residential Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **Residential Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **Residential Base Non-Fuel Additional Revenue Requirement**	**(5)** **Residential Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$129,458,147	$11,067,793	$140,525,940	$30,038,572	$170,564,512
2	Forfeited Discounts and Misc. Service Revenues	$761,746	$27,665	$789,410	($164,523)	$624,888
3	Non-Fuel Rider Revenues	$2,842,691	($2,842,691)	$0		$0
4	Fuel Revenues	$60,621,360	($6,088,841)	$54,532,519		$54,532,519
5	Other Operating Revenues	$1,750,775	$8,443	$1,759,217		$1,759,217
6	TOTAL OPERATING REVENUES	$195,434,718	$2,172,368	$197,607,086	$29,874,049	$227,481,136
	OPERATING EXPENSES					
7	Fuel Expense	$61,522,679	($7,070,595)	$54,452,084		$54,452,084
8	Non-Fuel Operating and Maintenance Expense	$47,476,250	$9,930,227	$57,406,477	$261,321	$57,667,798
9	Depreciation and Amortization	$45,654,239	$167,360	$45,821,599		$45,821,599
10	Federal Income Tax	($883,753)	$796,414	($87,339)	$5,860,186	$5,772,847
11	State Income Tax	$466,490	$231,466	$697,956	$1,707,079	$2,405,035
12	Taxes Other than Income Tax	$7,830,775	$312,645	$8,143,420		$8,143,420
13	(Gain)/Loss on Disposition of Property	$114,725	($150,199)	($35,474)		($35,474)
14	TOTAL ELECTRIC OPERATING EXPENSES	$162,181,405	$4,217,317	$166,398,722	$7,828,587	$174,227,309
15	**NET OPERATING INCOME**	$33,253,313	($2,044,949)	$31,208,364	$22,045,463	$53,253,827
	ADJUSTMENTS TO OPERATING INCOME					
16	*ADD:* AFUDC	$8,533,710	($8,533,710)	($0)		($0)
17	*LESS:* Charitable Donations	$181,239	($181,239)	($0)		($0)
18	Interest Expense on Customer Deposits	$14,826		$14,826		$14,826
19	Other Interest Expense/(Income)	$129,303		$129,303		$129,303
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$41,461,655	($10,397,420)	$31,064,235	$22,045,463	$53,109,698
21	**RATE BASE (from Line 38 below)**	$958,109,729	($158,099,475)	$800,010,254	$11,160,168	$811,170,422
22	**ROR EARNED ON AVERAGE RATE BASE**	4.3274%		3.8830%		6.5473%

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

Residential Class
Fully Adjusted Cost of Service and Revenue Requirement
Rate Base

LINE NO.	DESCRIPTION	(1) Residential Cost of Service	(2) Ratemaking Adjustments	(3) Residential Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) Residential Base Non-Fuel Additional Revenue Requirement	(5) Residential Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$27,375,595	$0	$27,375,595		$27,375,595
24	Investor Funds Advanced	$7,560,289	$11,756,113	$19,316,402	$11,160,168	$30,476,570
25	Total Additions	$118,379,886	($91,120,008)	$27,259,878		$27,259,878
26	Total Deductions	($116,421,974)	$94,510,632	($21,911,342)		($21,911,342)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$36,893,796	$15,146,737	$52,040,533	$11,160,168	$63,200,700
	NET UTILITY PLANT					
28	Utility Plant in Service	$1,389,748,037	$55,126,017	$1,444,874,054		$1,444,874,054
29	Acquisition Adjustments	$190,001	($190,000)	$1		$1
30	Construction Work in Progress	$212,789,477	($212,789,477)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$510,474,189	$23,856,667	$534,330,856		$534,330,856
32	Provision for Acquisition Adjustments	$32,444	($32,444)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$1,092,220,882	($181,677,682)	$910,543,200	$0	$910,543,200
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$1,498,955		$1,498,955		$1,498,955
35	Accumulated Deferred Income Taxes	$102,903,803	($7,348,275)	$95,555,528		$95,555,528
36	Other Cost Free Capital	$66,602,191	($1,083,196)	$65,518,995		$65,518,995
37	TOTAL RATE BASE DEDUCTIONS	$171,004,949	($8,431,471)	$162,573,478	$0	$162,573,478
38	**TOTAL RATE BASE**	$958,109,729	($158,099,475)	$800,010,254	$11,160,168	$811,170,422

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Small General Service, County, & Muni Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **SGS Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **SGS Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **SGS Base Non-Fuel Additional Revenue Requirement**	**(5)** **SGS Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$51,071,053	$8,506	$51,079,559	$12,811,604	$63,891,163
2	Forfeited Discounts and Misc. Service Revenues	$210,233	$9,925	$220,158	($24,952)	$195,206
3	Non-Fuel Rider Revenues	$1,325,418	($1,325,418)	$0		$0
4	Fuel Revenues	$29,697,669	($2,982,849)	$26,714,819		$26,714,819
5	Other Operating Revenues	$654,247	($3,312)	$650,936		$650,936
6	TOTAL OPERATING REVENUES	$82,958,619	($4,293,147)	$78,665,472	$12,786,653	$91,452,125
	OPERATING EXPENSES					
7	Fuel Expense	$30,139,214	($3,463,799)	$26,675,415		$26,675,415
8	Non-Fuel Operating and Maintenance Expense	$18,318,992	$2,154,433	$20,473,425	$111,850	$20,585,276
9	Depreciation and Amortization	$15,382,433	($10,351)	$15,372,082		$15,372,082
10	Federal Income Tax	$860,556	($257,328)	$603,228	$2,508,269	$3,111,497
11	State Income Tax	$492,785	($75,137)	$417,648	$730,662	$1,148,309
12	Taxes Other than Income Tax	$2,563,679	$103,168	$2,666,847		$2,666,847
13	(Gain)/Loss on Disposition of Property	$32,111	($49,489)	($17,378)		($17,378)
14	TOTAL ELECTRIC OPERATING EXPENSES	$67,789,770	($1,598,504)	$66,191,266	$3,350,782	$69,542,048
15	**NET OPERATING INCOME**	$15,168,849	($2,694,644)	$12,474,206	$9,435,871	$21,910,077
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$2,860,317	($2,860,317)	$0		$0
17	LESS: Charitable Donations	$80,574	($80,574)	($0)		($0)
18	Interest Expense on Customer Deposits	$6,309		$6,309		$6,309
19	Other Interest Expense/(Income)	$43,059		$43,059		$43,059
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$17,899,224	($5,474,386)	$12,424,838	$9,435,871	$21,860,709
21	**RATE BASE (from Line 38 below)**	$323,025,980	($53,256,265)	$269,769,715	$4,685,693	$274,455,408
22	**ROR EARNED ON AVERAGE RATE BASE**	5.5411%		4.6057%		7.9651%

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

Small General Service, County, & Muni Class
Fully Adjusted Cost of Service and Revenue Requirement
Rate Base

LINE NO.	DESCRIPTION	(1) SGS Cost of Service	(2) Ratemaking Adjustments	(3) SGS Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) SGS Base Non-Fuel Additional Revenue Requirement	(5) SGS Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$10,142,546	$0	$10,142,546		$10,142,546
24	Investor Funds Advanced	$3,209,504	$4,990,264	$8,199,768	$4,685,693	$12,885,462
25	Total Additions	$52,076,774	($41,657,258)	$10,419,516		$10,419,516
26	Total Deductions	($46,641,561)	$39,729,401	($6,912,160)		($6,912,160)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$18,787,263	$3,062,407	$21,849,670	$4,685,693	$26,535,363
	NET UTILITY PLANT					
28	Utility Plant in Service	$457,908,299	$18,176,797	$476,085,096		$476,085,096
29	Acquisition Adjustments	$63,521	($63,521)	$0		$0
30	Construction Work in Progress	$72,650,467	($72,650,467)	($0)		($0)
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$166,888,764	$7,792,236	$174,681,000		$174,681,000
32	Provision for Acquisition Adjustments	$10,847	($10,847)	$0		$0
33	TOTAL NET UTILITY PLANT	$363,722,676	($62,318,581)	$301,404,095	$0	$301,404,095
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$637,850		$637,850		$637,850
35	Accumulated Deferred Income Taxes	$37,069,533	($5,646,032)	$31,423,501		$31,423,501
36	Other Cost Free Capital	$21,776,576	($353,876)	$21,422,700		$21,422,700
37	TOTAL RATE BASE DEDUCTIONS	$59,483,959	($5,999,908)	$53,484,051	$0	$53,484,051
38	**TOTAL RATE BASE**	$323,025,980	($53,256,265)	$269,769,715	$4,685,693	$274,455,408

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Large General Service Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **LGS Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **LGS Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **LGS Base Non-Fuel Additional Revenue Requirement**	**(5)** **LGS Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$29,965,630	($4,341,179)	$25,624,451	$5,470,248	$31,094,698
2	Forfeited Discounts and Misc. Service Revenues	$88,823	$5,654	$94,477	($14,337)	$80,140
3	Non-Fuel Rider Revenues	$436,077	($436,077)	$0		$0
4	Fuel Revenues	$22,690,325	($2,279,028)	$20,411,297		$20,411,297
5	Other Operating Revenues	$363,114	($7,143)	$355,971		$355,971
6	TOTAL OPERATING REVENUES	$53,543,969	($7,057,773)	$46,486,195	$5,455,911	$51,942,106
	OPERATING EXPENSES					
7	Fuel Expense	$23,027,685	($2,646,495)	$20,381,190		$20,381,190
8	Non-Fuel Operating and Maintenance Expense	$8,046,649	$1,806,161	$9,852,811	$47,725	$9,900,536
9	Depreciation and Amortization	$6,904,539	($99,098)	$6,805,441		$6,805,441
10	Federal Income Tax	$1,848,541	($1,056,585)	$791,956	$1,070,248	$1,862,205
11	State Income Tax	$652,303	($307,869)	$344,434	$311,765	$656,199
12	Taxes Other than Income Tax	$1,057,939	$43,722	$1,101,661		$1,101,661
13	(Gain)/Loss on Disposition of Property	$7,818	($21,096)	($13,278)		($13,278)
14	TOTAL ELECTRIC OPERATING EXPENSES	$41,545,474	($2,281,259)	$39,264,215	$1,429,738	$40,693,953
15	**NET OPERATING INCOME**	$11,998,495	($4,776,514)	$7,221,980	$4,026,173	$11,248,153
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$1,357,539	($1,357,539)	($0)		($0)
17	LESS: Charitable Donations	$51,669	($51,669)	($0)		($0)
18	Interest Expense on Customer Deposits	$4,080		$4,080		$4,080
19	Other Interest Expense/(Income)	$18,843		$18,843		$18,843
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$13,281,442	($6,082,384)	$7,199,057	$4,026,173	$11,225,230
21	**RATE BASE (from Line 38 below)**	$144,937,388	($25,963,388)	$118,974,000	$2,981,225	$121,955,225
22	**ROR EARNED ON AVERAGE RATE BASE**	9.1636%		6.0510%		9.2044%

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Large General Service Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Rate Base** DESCRIPTION	**(1)** **LGS Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **LGS Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **LGS Base Non-Fuel Additional Revenue Requirement**	**(5)** **LGS Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$5,526,099	$0	$5,526,099		$5,526,099
24	Investor Funds Advanced	$2,071,572	$3,220,866	$5,292,438	$2,981,225	$8,273,663
25	Total Additions	$35,972,717	($29,975,297)	$5,997,420		$5,997,420
26	Total Deductions	($29,170,862)	$26,256,538	($2,914,324)		($2,914,324)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$14,399,526	($497,893)	$13,901,633	$2,981,225	$16,882,858
	NET UTILITY PLANT					
28	Utility Plant in Service	$195,196,772	$7,794,053	$202,990,825		$202,990,825
29	Acquisition Adjustments	$30,223	($30,223)	($0)		($0)
30	Construction Work in Progress	$35,680,137	($35,680,137)	($0)		($0)
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$71,740,785	$3,331,476	$75,072,261		$75,072,261
32	Provision for Acquisition Adjustments	$5,161	($5,161)	$0		$0
33	TOTAL NET UTILITY PLANT	$159,161,186	($31,242,622)	$127,918,564	$0	$127,918,564
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$412,511		$412,511		$412,511
35	Accumulated Deferred Income Taxes	$19,106,923	($5,629,833)	$13,477,090		$13,477,090
36	Other Cost Free Capital	$9,103,890	($147,295)	$8,956,595		$8,956,595
37	TOTAL RATE BASE DEDUCTIONS	$28,623,324	($5,777,127)	$22,846,197	$0	$22,846,197
38	**TOTAL RATE BASE**	$144,937,388	($25,963,388)	$118,974,000	$2,981,225	$121,955,225

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Schedule NS Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **Schedule NS Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **Schedule NS Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **Schedule NS Base Non-Fuel Additional Revenue Requirement**	**(5)** **Schedule NS Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$19,246,714	$2,779,598	$22,026,313	$4,462,432	$26,488,745
2	Forfeited Discounts and Misc. Service Revenues	$79,098	$5,043	$84,142	($14,866)	$69,275
3	Non-Fuel Rider Revenues	$0	$0	$0		$0
4	Fuel Revenues	$28,135,491	($2,825,943)	$25,309,548		$25,309,548
5	Other Operating Revenues	$330,189	($14,381)	$315,808		$315,808
6	TOTAL OPERATING REVENUES	$47,791,492	($55,682)	$47,735,810	$4,447,566	$52,183,376
	OPERATING EXPENSES					
7	Fuel Expense	$28,553,810	($3,281,594)	$25,272,216		$25,272,216
8	Non-Fuel Operating and Maintenance Expense	$4,795,772	$2,264,643	$7,060,416	$38,905	$7,099,321
9	Depreciation and Amortization	$3,777,919	($171,621)	$3,606,298		$3,606,298
10	Federal Income Tax	$1,624,415	$306,096	$1,930,511	$872,448	$2,802,959
11	State Income Tax	$517,201	$89,123	$606,324	$254,145	$860,469
12	Taxes Other than Income Tax	$402,594	$19,110	$421,704		$421,704
13	(Gain)/Loss on Disposition of Property	($7,371)	($9,094)	($16,465)		($16,465)
14	TOTAL ELECTRIC OPERATING EXPENSES	$39,664,340	($783,336)	$38,881,004	$1,165,498	$40,046,502
15	**NET OPERATING INCOME**	$8,127,152	$727,654	$8,854,806	$3,282,067	$12,136,874
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$707,215	($707,215)	($0)		($0)
17	LESS: Charitable Donations	$55,452	($55,452)	($0)		($0)
18	Interest Expense on Customer Deposits	$3,641		$3,641		$3,641
19	Other Interest Expense/(Income)	$8,478		$8,478		$8,478
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$8,766,796	$75,891	$8,842,687	$3,282,067	$12,124,755
21	**RATE BASE (from Line 38 below)**	$71,029,788	($15,009,531)	$56,020,257	$2,831,389	$58,851,646
22	**ROR EARNED ON AVERAGE RATE BASE**	12.3424%		15.7848%		20.6022%

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

Schedule NS Class
Fully Adjusted Cost of Service and Revenue Requirement
Rate Base

LINE NO.	DESCRIPTION	(1) Schedule NS Cost of Service	(2) Ratemaking Adjustments	(3) Schedule NS Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) Schedule NS Base Non-Fuel Additional Revenue Requirement	(5) Schedule NS Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$4,487,694	$0	$4,487,694		$4,487,694
24	Investor Funds Advanced	$1,848,587	$2,874,833	$4,723,420	$2,831,389	$7,554,809
25	Total Additions	$40,274,433	($34,960,358)	$5,314,075		$5,314,075
26	Total Deductions	($29,029,195)	$27,706,943	($1,322,252)		($1,322,252)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$17,581,519	($4,378,583)	$13,202,936	$2,831,389	$16,034,325
	NET UTILITY PLANT					
28	Utility Plant in Service	$84,139,751	$3,396,326	$87,536,077		$87,536,077
29	Acquisition Adjustments	$15,555	($15,555)	($0)		($0)
30	Construction Work in Progress	$21,040,184	($21,040,184)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$33,581,189	$1,532,157	$35,113,346		$35,113,346
32	Provision for Acquisition Adjustments	$2,656	($2,656)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$71,611,645	($19,188,914)	$52,422,731	$0	$52,422,731
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$368,147		$368,147		$368,147
35	Accumulated Deferred Income Taxes	$14,294,421	($8,502,170)	$5,792,251		$5,792,251
36	Other Cost Free Capital	$3,500,808	($55,796)	$3,445,012		$3,445,012
37	TOTAL RATE BASE DEDUCTIONS	$18,163,376	($8,557,966)	$9,605,410	$0	$9,605,410
38	**TOTAL RATE BASE**	$71,029,788	($15,009,531)	$56,020,257	$2,831,389	$58,851,646

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	6VP Class Fully Adjusted Cost of Service and Revenue Requirement Adjusted Net Operating Income and Rate of Return DESCRIPTION	(1) 6VP Cost of Service	(2) Ratemaking Adjustments	(3) 6VP Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) 6VP Base Non-Fuel Additional Revenue Requirement	(5) 6VP Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$11,790,963	($1,745,938)	$10,045,025	$2,021,332	$12,066,357
2	Forfeited Discounts and Misc. Service Revenues	$36,671	$2,338	$39,009	($8,098)	$30,911
3	Non-Fuel Rider Revenues	$223	($223)	$0		$0
4	Fuel Revenues	$10,169,761	($1,021,456)	$9,148,305		$9,148,305
5	Other Operating Revenues	$168,877	($3,155)	$165,723		$165,723
6	TOTAL OPERATING REVENUES	$22,166,496	($2,768,434)	$19,398,061	$2,013,234	$21,411,295
	OPERATING EXPENSES					
7	Fuel Expense	$10,320,965	($1,186,154)	$9,134,811		$9,134,811
8	Non-Fuel Operating and Maintenance Expense	$3,502,771	$1,085,560	$4,588,331	$17,611	$4,605,942
9	Depreciation and Amortization	$3,032,207	($50,129)	$2,982,078		$2,982,078
10	Federal Income Tax	$500,991	($449,858)	$51,133	$394,922	$446,055
11	State Income Tax	$192,118	($131,082)	$61,036	$115,041	$176,077
12	Taxes Other than Income Tax	$462,558	$19,213	$481,771		$481,771
13	(Gain)/Loss on Disposition of Property	$3,286	($9,237)	($5,951)		($5,951)
14	TOTAL ELECTRIC OPERATING EXPENSES	$18,014,896	($721,688)	$17,293,208	$527,574	$17,820,783
15	**NET OPERATING INCOME**	$4,151,600	($2,046,747)	$2,104,853	$1,485,660	$3,590,513
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$614,820	($614,820)	($0)		($0)
17	LESS: Charitable Donations	$22,986	($22,986)	$0		$0
18	Interest Expense on Customer Deposits	$1,688		$1,688		$1,688
19	Other Interest Expense/(Income)	$8,445		$8,445		$8,445
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$4,733,301	($2,638,581)	$2,094,720	$1,485,660	$3,580,379
21	**RATE BASE (from Line 38 below)**	$65,056,711	($11,624,666)	$53,432,045	$1,292,887	$54,724,932
22	**ROR EARNED ON AVERAGE RATE BASE**	7.2757%		3.9203%		6.5425%

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

6VP Class
Fully Adjusted Cost of Service and Revenue Requirement
Rate Base

LINE NO.	DESCRIPTION	(1) 6VP Cost of Service	(2) Ratemaking Adjustments	(3) 6VP Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) 6VP Base Non-Fuel Additional Revenue Requirement	(5) 6VP Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$2,458,505	$0	$2,458,505		$2,458,505
24	Investor Funds Advanced	$857,457	$1,333,396	$2,190,853	$1,292,887	$3,483,739
25	Total Additions	$16,132,229	($13,452,493)	$2,679,736		$2,679,736
26	Total Deductions	($13,092,317)	$11,792,031	($1,300,286)		($1,300,286)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$6,355,874	($327,066)	$6,028,808	$1,292,887	$7,321,694
	NET UTILITY PLANT					
28	Utility Plant in Service	$85,465,990	$3,419,845	$88,885,835		$88,885,835
29	Acquisition Adjustments	$13,733	($13,733)	$0		$0
30	Construction Work in Progress	$15,909,270	($15,909,270)	($0)		($0)
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$30,050,975	$1,400,596	$31,451,571		$31,451,571
32	Provision for Acquisition Adjustments	$2,345	($2,345)	$0		$0
33	TOTAL NET UTILITY PLANT	$71,335,673	($13,901,410)	$57,434,263	$0	$57,434,263
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$170,631		$170,631		$170,631
35	Accumulated Deferred Income Taxes	$8,475,387	($2,539,347)	$5,936,040		$5,936,040
36	Other Cost Free Capital	$3,988,818	($64,464)	$3,924,354		$3,924,354
37	TOTAL RATE BASE DEDUCTIONS	$12,634,836	($2,603,810)	$10,031,026	$0	$10,031,026
38	**TOTAL RATE BASE**	$65,056,711	($11,624,666)	$53,432,045	$1,292,887	$54,724,932

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Street and Outdoor Lighting Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **St. & Out. Lighting Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **St. & Out. Lighting Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **St. & Out. Lighting Base Non-Fuel Additional Revenue Requirement**	**(5)** **St. & Out. Lighting Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
	Base Non-Fuel Rate Revenues, Including Facilities Charges &					
1	Load Management	$5,178,064	$72,424	$5,250,488	$2,067,365	$7,317,853
2	Forfeited Discounts and Misc. Service Revenues	$76,019	$1,716	$77,735	($31,835)	$45,901
3	Non-Fuel Rider Revenues	$0	$0	$0		$0
4	Fuel Revenues	$913,313	($91,734)	$821,579		$821,579
5	Other Operating Revenues	$64,555	($594)	$63,960		$63,960
6	TOTAL OPERATING REVENUES	$6,231,951	($18,187)	$6,213,763	$2,035,531	$8,249,294
	OPERATING EXPENSES					
7	Fuel Expense	$926,892	($106,525)	$820,368		$820,368
8	Non-Fuel Operating and Maintenance Expense	$2,464,744	$188,643	$2,653,387	$17,806	$2,671,193
9	Depreciation and Amortization	$2,202,631	$124,613	$2,327,244		$2,327,244
10	Federal Income Tax	($184,619)	($11,572)	($196,191)	$399,296	$203,105
11	State Income Tax	($25,817)	($3,371)	($29,188)	$116,315	$87,127
12	Taxes Other than Income Tax	$315,941	$11,675	$327,616		$327,616
13	(Gain)/Loss on Disposition of Property	$5,554	($6,089)	($535)		($535)
14	TOTAL ELECTRIC OPERATING EXPENSES	$5,705,326	$197,375	$5,902,701	$533,417	$6,436,118
15	**NET OPERATING INCOME**	$526,625	($215,562)	$311,063	$1,502,113	$1,813,176
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$33,189	($33,189)	($0)		($0)
17	LESS: Charitable Donations	$5,639	($5,639)	($0)		($0)
18	Interest Expense on Customer Deposits	$468		$468		$468
19	Other Interest Expense/(Income)	$4,459		$4,459		$4,459
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$549,248	($243,112)	$306,136	$1,502,113	$1,808,249
21	**RATE BASE (from Line 38 below)**	$32,464,903	($753,212)	$31,711,691	$247,423	$31,959,113
22	**ROR EARNED ON AVERAGE RATE BASE**	1.6918%		0.9654%		5.6580%

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

Street and Outdoor Lighting Class
Fully Adjusted Cost of Service and Revenue Requirement
Rate Base

LINE NO.	DESCRIPTION	(1) St. & Out. Lighting Cost of Service	(2) Ratemaking Adjustments	(3) St. & Out. Lighting Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) St. & Out. Lighting Base Non-Fuel Additional Revenue Requirement	(5) St. & Out. Lighting Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$736,690	$0	$736,690		$736,690
24	Investor Funds Advanced	$241,476	$374,875	$616,351	$247,423	$863,773
25	Total Additions	$1,675,847	($1,104,533)	$571,314		$571,314
26	Total Deductions	($1,652,223)	$881,615	($770,608)		($770,608)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$1,001,790	$151,957	$1,153,747	$247,423	$1,401,169
	NET UTILITY PLANT					
28	Utility Plant in Service	$56,336,264	$2,122,846	$58,459,110		$58,459,110
29	Acquisition Adjustments	$0	$0	$0		$0
30	Construction Work in Progress	$2,240,601	($2,240,601)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$20,901,838	$1,007,899	$21,909,737		$21,909,737
32	Provision for Acquisition Adjustments	$0	$0	$0		$0
33	TOTAL NET UTILITY PLANT	$37,675,027	($1,125,654)	$36,549,373	$0	$36,549,373
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$47,328		$47,328		$47,328
35	Accumulated Deferred Income Taxes	$3,569,714	($177,328)	$3,392,386		$3,392,386
36	Other Cost Free Capital	$2,594,872	($43,157)	$2,551,715		$2,551,715
37	TOTAL RATE BASE DEDUCTIONS	$6,211,914	($220,485)	$5,991,429	$0	$5,991,429
38	**TOTAL RATE BASE**	$32,464,903	($753,212)	$31,711,691	$247,423	$31,959,113

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Traffic Lighting Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **Traffic Lighting Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **Traffic Lighting Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **Traffic Lighting Base Non-Fuel Additional Revenue Requirement**	**(5)** **Traffic Lighting Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$51,314	($357)	$50,957	$11,467	$62,424
2	Forfeited Discounts and Misc. Service Revenues	$899	$20	$919	($436)	$483
3	Non-Fuel Rider Revenues	$0	$0	$0		$0
4	Fuel Revenues	$16,290	($1,636)	$14,654		$14,654
5	Other Operating Revenues	$618	($4)	$613		$613
6	TOTAL OPERATING REVENUES	$69,121	($1,978)	$67,143	$11,031	$78,174
	OPERATING EXPENSES					
7	Fuel Expense	$16,532	($1,900)	$14,632		$14,632
8	Non-Fuel Operating and Maintenance Expense	$26,173	$3,009	$29,182	$96	$29,278
9	Depreciation and Amortization	$12,847	$291	$13,138		$13,138
10	Federal Income Tax	$547	($431)	$116	$2,164	$2,280
11	State Income Tax	$346	($126)	$220	$630	$851
12	Taxes Other than Income Tax	$2,163	$97	$2,260		$2,260
13	(Gain)/Loss on Disposition of Property	$29	($38)	($9)		($9)
14	TOTAL ELECTRIC OPERATING EXPENSES	$58,637	$902	$59,539	$2,891	$62,430
15	**NET OPERATING INCOME**	$10,484	($2,880)	$7,603	$8,140	$15,744
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$1,217	($1,217)	($0)		($0)
17	LESS: Charitable Donations	$71	($71)	($0)		($0)
18	Interest Expense on Customer Deposits	$5		$5		$5
19	Other Interest Expense/(Income)	$31		$31		$31
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$11,594	($4,027)	$7,567	$8,140	$15,707
21	**RATE BASE (from Line 38 below)**	$227,014	($19,485)	$207,529	$2,075	$209,605
22	**ROR EARNED ON AVERAGE RATE BASE**	5.1071%		3.6462%		7.4938%

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

Traffic Lighting Class
Fully Adjusted Cost of Service and Revenue Requirement
Rate Base

LINE NO.	DESCRIPTION	(1) Traffic Lighting Cost of Service	(2) Ratemaking Adjustments	(3) Traffic Lighting Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) Traffic Lighting Base Non-Fuel Additional Revenue Requirement	(5) Traffic Lighting Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$6,180	$0	$6,180		$6,180
24	Investor Funds Advanced	$2,676	$4,158	$6,834	$2,075	$8,909
25	Total Additions	$28,231	($21,925)	$6,306		$6,306
26	Total Deductions	($31,864)	$22,222	($9,642)		($9,642)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$5,223	$4,455	$9,678	$2,075	$11,753
	NET UTILITY PLANT					
28	Utility Plant in Service	$352,878	$13,661	$366,539		$366,539
29	Acquisition Adjustments	$25	($25)	($0)		($0)
30	Construction Work in Progress	$35,196	($35,196)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$124,030	$5,907	$129,937		$129,937
32	Provision for Acquisition Adjustments	$4	($4)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$264,065	($27,463)	$236,602	$0	$236,602
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$525		$525		$525
35	Accumulated Deferred Income Taxes	$26,216	($3,269)	$22,947		$22,947
36	Other Cost Free Capital	$15,533	($255)	$15,278		$15,278
37	TOTAL RATE BASE DEDUCTIONS	$42,274	($3,524)	$38,750	$0	$38,750
38	**TOTAL RATE BASE**	$227,014	($19,485)	$207,529	$2,075	$209,605

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Total of All North Carolina Classes** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	(1) Total NC Jurisdiction Cost of Service	(2) Ratemaking Adjustments	(3) Total NC Jurisdiction Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) Total NC Jurisdiction Base Non-Fuel Additional Revenue Requirement	(5) Total NC Jurisdiction Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$246,761,884	$7,840,847	$254,602,731	$56,883,021	$311,485,752
2	Forfeited Discounts and Misc. Service Revenues	$1,253,489	$52,361	$1,305,850	($259,047)	$1,046,803
3	Non-Fuel Rider Revenues	$4,604,409	($4,604,409)	$0	$0	$0
4	Fuel Revenues	$152,244,208	($15,291,487)	$136,952,721	$0	$136,952,721
5	Other Operating Revenues	$3,332,375	($20,146)	$3,312,229	$0	$3,312,229
6	TOTAL OPERATING REVENUES	$408,196,365	($12,022,834)	$396,173,531	$56,623,974	$452,797,505
	OPERATING EXPENSES					
7	Fuel Expense	$154,507,777	($17,757,061)	$136,750,716	$0	$136,750,716
8	Non-Fuel Operating and Maintenance Expense	$84,631,351	$17,432,677	$102,064,028	$495,315	$102,559,343
9	Depreciation and Amortization	$76,966,815	($38,935)	$76,927,880	$0	$76,927,880
10	Federal Income Tax	$3,766,678	($673,265)	$3,093,413	$11,107,535	$14,200,947
11	State Income Tax	$2,295,426	($196,997)	$2,098,429	$3,235,638	$5,334,067
12	Taxes Other than Income Tax	$12,635,649	$509,630	$13,145,279	$0	$13,145,279
13	(Gain)/Loss on Disposition of Property	$156,152	($245,242)	($89,090)	$0	($89,090)
14	TOTAL ELECTRIC OPERATING EXPENSES	$334,959,848	($969,192)	$333,990,656	$14,838,487	$348,829,142
15	**NET OPERATING INCOME**	$73,236,517	($11,053,642)	$62,182,875	$41,785,487	$103,968,363
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$14,108,007	($14,108,009)	($2)	$0	($2)
17	LESS: Charitable Donations	$397,630	($397,631)	($1)	$0	($1)
18	Interest Expense on Customer Deposits	$31,017	$0	$31,017	$0	$31,017
19	Other Interest Expense/(Income)	$212,618	$0	$212,618	$0	$212,618
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$86,703,259	($24,764,019)	$61,939,240	$41,785,487	$103,724,727
21	**RATE BASE (from Line 38 below)**	$1,594,851,513	($264,726,022)	$1,330,125,491	$23,200,860	$1,353,326,351
22	**ROR EARNED ON AVERAGE RATE BASE**	5.4364%		4.6566%		7.6644%

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

Total of All North Carolina Classes
Fully Adjusted Cost of Service and Revenue Requirement
Rate Base

LINE NO.	DESCRIPTION	(1) Total NC Jurisdiction Cost of Service	(2) Ratemaking Adjustments	(3) Total NC Jurisdiction Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) Total NC Jurisdiction Base Non-Fuel Additional Revenue Requirement	(5) Total NC Jurisdiction Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$50,733,309	$0	$50,733,309	$0	$50,733,309
24	Investor Funds Advanced	$15,791,561	$24,554,504	$40,346,065	$23,200,860	$63,546,925
25	Total Additions	$264,540,117	($212,291,872)	$52,248,245	$0	$52,248,245
26	Total Deductions	($236,039,996)	$200,899,380	($35,140,616)	$0	($35,140,616)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$95,024,991	$13,162,012	$108,187,003	$23,200,860	$131,387,864
	NET UTILITY PLANT					
28	Utility Plant in Service	$2,269,147,991	$90,049,544	$2,359,197,535	$0	$2,359,197,535
29	Acquisition Adjustments	$313,058	($313,057)	$1	$0	$1
30	Construction Work in Progress	$360,345,332	($360,345,332)	$0	$0	$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$833,761,770	$38,926,938	$872,688,708	$0	$872,688,708
32	Provision for Acquisition Adjustments	$53,457	($53,457)	$0	$0	$0
33	TOTAL NET UTILITY PLANT	$1,795,991,154	($309,482,326)	$1,486,508,828	$0	$1,486,508,828
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$3,135,947	$0	$3,135,947	$0	$3,135,947
35	Accumulated Deferred Income Taxes	$185,445,997	($29,846,253)	$155,599,744	$0	$155,599,744
36	Other Cost Free Capital	$107,582,688	($1,748,038)	$105,834,650	$0	$105,834,650
37	TOTAL RATE BASE DEDUCTIONS	$296,164,632	($31,594,291)	$264,570,341	$0	$264,570,341
38	**TOTAL RATE BASE**	$1,594,851,513	($264,726,022)	$1,330,125,491	$23,200,860	$1,353,326,351

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
SUMMARY OF NORTH CAROLINA JURISDICTION AND CUSTOMER CLASS RATES OF RETURN
PER BOOKS, ANNUALIZED, FULLY ADJUSTED AND FULLY ADJUSTED WITH INCREASE

PER BOOKS CLASS RATE OF RETURNS - FROM ITEM 45a

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$86,703,258	$41,461,656	$17,899,224	$13,281,441	$8,766,795	$4,733,302	$549,247	$11,593
Rate Base	$1,594,851,513	$958,109,730	$323,025,980	$144,937,388	$71,029,787	$65,056,712	$32,464,902	$227,014
ROR	5.4364%	4.3274%	5.5411%	9.1636%	12.3424%	7.2757%	1.6918%	5.1067%
Index		0.80	1.02	1.69	2.27	1.34	0.31	0.94

PER BOOKS CLASS RATE OF RETURNS WITH ANNUALIZED REVENUE - FROM ITEM 45b

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$84,327,737	$43,671,531	$17,176,487	$10,481,666	$9,185,361	$3,268,780	$534,601	$9,310
Rate Base	$1,594,851,513	$958,109,729	$323,025,980	$144,937,388	$71,029,788	$65,056,711	$32,464,903	$227,014
ROR	5.2875%	4.5581%	5.3174%	7.2319%	12.9317%	5.0245%	1.6467%	4.1011%
Index		0.86	1.01	1.37	2.45	0.95	0.31	0.78

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS BEFORE REVENUE INCREASE - FROM ITEM 45c, COL. 3

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$61,939,240	$31,064,235	$12,424,838	$7,199,057	$8,842,687	$2,094,720	$306,136	$7,567
Rate Base	$1,330,125,491	$800,010,254	$269,769,715	$118,974,000	$56,020,257	$53,432,045	$31,711,691	$207,529
ROR	4.6566%	3.8830%	4.6057%	6.0510%	15.7848%	3.9203%	0.9654%	3.6462%
Index		0.83	0.99	1.30	3.39	0.84	0.21	0.78

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS AND AFTER REVENUE INCREASE - FROM ITEM 45c, COLS. 4 & 5

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Revenue Increase	$56,623,974	$29,874,049	$12,786,653	$5,455,911	$4,447,566	$2,013,234	$2,035,531	$11,031
Adjusted NOI	$103,724,727	$53,109,698	$21,860,709	$11,225,230	$12,124,755	$3,580,379	$1,808,249	$15,707
Rate Base	$1,353,326,351	$811,170,422	$274,455,408	$121,955,225	$58,851,646	$54,724,932	$31,959,113	$209,605
ROR	7.6644%	6.5473%	7.9651%	9.2044%	20.6022%	6.5425%	5.6580%	7.4938%
Index		0.85	1.04	1.20	2.69	0.85	0.74	0.98

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 0.0000%
Demand 100.0000%

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
1	NOI (COS Sch 1, Ln 36)	$41,461,656	$5,135,655	$18,550,526	($0)	$18,550,526	$9,119,038	$7,114,944	$1,541,493
2	NOI Ratio (Based on Ln 1)	100.0000%	12.3865%	44.7414%	0.0000%	44.7414%	21.9939%	17.1603%	3.7179%
3	Rate Base (COS Sch 1, Ln 38)	$958,109,730	$118,676,427	$428,671,709	($0)	$428,671,709	$210,725,770	$164,414,480	$35,621,343
4	Rate Base Ratio (Based on Ln 3)	100.0000%	12.3865%	44.7414%	0.0000%	44.7414%	21.9939%	17.1603%	3.7179%
5	Rate of Return (Ln 1 / Ln 3)	4.33%	4.33%	4.33%	89.44%	4.33%	4.33%	4.33%	4.33%

PART B

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
6	Change in NOI (Item 45b, Pg 1, Col 2, Ln 20)	$2,209,876							
7	Allocated on NOI Ratio (Ln 2)	$2,209,876	$273,727	$988,730	$0	$988,730	$486,038	$379,221	$82,160
8	Annualized NOI (Ln 1 + Ln 7)	$43,671,533	$5,409,382	$19,539,256	($0)	$19,539,256	$9,605,076	$7,494,165	$1,623,653
9	Annualized Rate of Return (Ln 8 / Ln 3)	4.56%	4.56%	4.56%	89.44%	4.56%	4.56%	4.56%	4.56%

PART C

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
10	NOI After All Adjustments and Increase	$53,109,698 *							
11	Allocated on NOI Ratio	$53,109,697	$6,578,442	$23,762,023	$0	$23,762,022	$11,680,898	$9,113,782	$1,974,553
12	Final Rate Base After All Adjustments	$811,170,422 #							
13	Allocated on Rate Base Ratio	$811,170,421	$100,475,764	$362,929,005	$0	$362,929,005	$178,408,074	$139,199,258	$30,158,320
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	6.55%	6.55%	6.55%	#DIV/0!	6.55%	6.55%	6.55%	6.55%

*** Total from NCUC Form E-1, Item 45c, Page 1, Column 5, Line 20**
 # Total from NCUC Form E-1, Item 45c, Page 1, Column 5, Line 21

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 0.0000%
Demand 100.0000%

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
1	NOI (COS Sch 1, Ln 36)	$17,899,224	$1,244,031	$7,974,098	$0	$7,974,098	$3,905,862	$3,807,743	$967,490
2	NOI Ratio (Based on Ln 1)	100.0000%	6.9502%	44.5500%	0.0000%	44.5500%	21.8214%	21.2732%	5.4052%
3	Rate Base (COS Sch 1, Ln 38)	$323,025,980	$22,450,928	$143,907,965	$0	$143,907,965	$70,488,805	$68,718,059	$17,460,223
4	Rate Base Ratio (Based on Ln 3)	100.0000%	6.9502%	44.5500%	0.0000%	44.5500%	21.8214%	21.2732%	5.4052%
5	Rate of Return (Ln 1 / Ln 3)	5.54%	5.54%	5.54%	#DIV/0!	5.54%	5.54%	5.54%	5.54%

PART B

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
6	Change in NOI (Item 45b, Pg 2, Col 2, Ln 20)	($722,737)							
7	Allocated on NOI Ratio (Ln 2)	($722,737)	($50,232)	($321,979)	$0	($321,979)	($157,711)	($153,750)	($39,065)
8	Annualized NOI (Ln 1 + Ln 7)	$17,176,487	$1,193,799	$7,652,119	$0	$7,652,119	$3,748,151	$3,653,993	$928,425
9	Annualized Rate of Return (Ln 8 / Ln 3)	5.32%	5.32%	5.32%	#DIV/0!	5.32%	5.32%	5.32%	5.32%

PART C

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
10	NOI After All Adjustments and Increase	$21,860,709 *							
11	Allocated on NOI Ratio	$21,860,709	$1,519,362	$9,738,938	$0	$9,738,938	$4,770,314	$4,650,479	$1,181,616
12	Final Rate Base After All Adjustments	$274,455,408 #							
13	Allocated on Rate Base Ratio	$274,455,409	$19,075,180	$122,269,792	$0	$122,269,792	$59,890,024	$58,385,530	$14,834,883
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	7.97%	7.97%	7.97%	#DIV/0!	7.97%	7.97%	7.97%	7.97%

*** Total from NCUC Form E-1, Item 45c, Page 3, Column 5, Line 20**
 # Total from NCUC Form E-1, Item 45c, Page 3, Column 5, Line 21

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 0.0000%
Demand 100.0000%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	NOI (COS Sch 1, Ln 36)	$13,281,442	$47,623	$6,368,208	$0	$6,368,208	$3,078,475	$2,562,645	$1,224,491
2	NOI Ratio (Based on Ln 1)	100.0000%	0.3586%	47.9482%	0.0000%	47.9482%	23.1788%	19.2949%	9.2196%
3	Rate Base (COS Sch 1, Ln 38)	$144,937,389	$519,692	$69,494,824	$0	$69,494,824	$33,594,704	$27,965,571	$13,362,598
4	Rate Base Ratio (Based on Ln 3)	100.0000%	0.3586%	47.9482%	0.0000%	47.9482%	23.1788%	19.2949%	9.2196%
5	Rate of Return (Ln 1 / Ln 3)	9.16%	9.16%	9.16%	#DIV/0!	9.16%	9.16%	9.16%	9.16%

PART B

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
6	Change in NOI (Item 45b, Pg 3, Col 2, Ln 20)	($2,799,775)							
7	Allocated on NOI Ratio (Ln 2)	($2,799,776)	($10,039)	($1,342,441)	$0	($1,342,441)	($648,954)	($540,215)	($258,127)
8	Annualized NOI (Ln 1 + Ln 7)	$10,481,667	$37,584	$5,025,767	$0	$5,025,767	$2,429,521	$2,022,430	$966,364
9	Annualized Rate of Return (Ln 8 / Ln 3)	7.23%	7.23%	7.23%	#DIV/0!	7.23%	7.23%	7.23%	7.23%

PART C

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
10	NOI After All Adjustments and Increase	$11,225,230 *							
11	Allocated on NOI Ratio	$11,225,229	$40,250	$5,382,292	$0	$5,382,292	$2,601,870	$2,165,900	$1,034,917
12	Final Rate Base After All Adjustments	$121,955,225 #							
13	Allocated on Rate Base Ratio	$121,955,224	$437,286	$58,475,297	$0	$58,475,297	$28,267,721	$23,531,178	$11,243,742
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	9.20%	9.20%	9.20%	#DIV/0!	9.20%	9.20%	9.20%	9.20%

*** Total from NCUC Form E-1, Item 45c, Page 5, Column 5, Line 20**
 # Total from NCUC Form E-1, Item 45c, Page 5, Column 5, Line 21

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 0.0000%
Demand 100.0000%

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
1	NOI (COS Sch 1, Ln 36)	$8,766,794	$7,999	$4,573,530	$0	$4,573,530	$2,137,192	$0	$2,048,073
2	NOI Ratio (Based on Ln 1)	100.0000%	0.0912%	52.1688%	0.0000%	52.1688%	24.3783%	0.0000%	23.3617%
3	Rate Base (COS Sch 1, Ln 38)	$71,029,788	$64,809	$37,055,378	$0	$37,055,378	$17,315,827	$0	$16,593,774
4	Rate Base Ratio (Based on Ln 3)	100.0000%	0.0912%	52.1688%	0.0000%	52.1688%	24.3783%	0.0000%	23.3617%
5	Rate of Return (Ln 1 / Ln 3)	12.34%	12.34%	12.34%	#DIV/0!	12.34%	12.34%	#DIV/0!	12.34%

PART B

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
6	Change in NOI (Item 45b, Pg 4, Col 2, Ln 20)	$418,564							
7	Allocated on NOI Ratio (Ln 2)	$418,565	$382	$218,360	$0	$218,360	$102,039	$0	$97,784
8	Annualized NOI (Ln 1 + Ln 7)	$9,185,358	$8,381	$4,791,890	$0	$4,791,890	$2,239,231	$0	$2,145,857
9	Annualized Rate of Return (Ln 8 / Ln 3)	12.93%	12.93%	12.93%	#DIV/0!	12.93%	12.93%	#DIV/0!	12.93%

PART C

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
10	NOI After All Adjustments and Increase	$12,124,755 *							
11	Allocated on NOI Ratio	$12,124,754	$11,063	$6,325,337	$0	$6,325,337	$2,955,804	$0	$2,832,550
12	Final Rate Base After All Adjustments	$58,851,646 #							
13	Allocated on Rate Base Ratio	$58,851,646	$53,697	$30,702,189	$0	$30,702,189	$14,347,008	$0	$13,748,752
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	20.60%	20.60%	20.60%	#DIV/0!	20.60%	20.60%	#DIV/0!	20.60%

*** Total from NCUC Form E-1, Item 45c, Page 7, Column 5, Line 20**
 # Total from NCUC Form E-1, Item 45c, Page 7, Column 5, Line 21

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 0.0000%
Demand 100.0000%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	NOI (COS Sch 1, Ln 36)	$4,733,302	$4,619	$2,281,682	$0	$2,281,682	$1,109,651	$901,982	$435,368
2	NOI Ratio (Based on Ln 1)	100.0000%	0.0976%	48.2049%	0.0000%	48.2049%	23.4435%	19.0561%	9.1980%
3	Rate Base (COS Sch 1, Ln 38)	$65,056,712	$63,473	$31,360,499	$0	$31,360,499	$15,251,567	$12,397,265	$5,983,908
4	Rate Base Ratio (Based on Ln 3)	100.0000%	0.0976%	48.2049%	0.0000%	48.2049%	23.4435%	19.0561%	9.1980%
5	Rate of Return (Ln 1 / Ln 3)	7.28%	7.28%	7.28%	#DIV/0!	7.28%	7.28%	7.28%	7.28%

PART B

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
6	Change in NOI (Item 45b, Pg 5, Col 2, Ln 20)	($1,464,520)							
7	Allocated on NOI Ratio (Ln 2)	($1,464,520)	($1,429)	($705,970)	$0	($705,970)	($343,335)	($279,080)	($134,706)
8	Annualized NOI (Ln 1 + Ln 7)	$3,268,782	$3,190	$1,575,712	$0	$1,575,712	$766,316	$622,902	$300,662
9	Annualized Rate of Return (Ln 8 / Ln 3)	5.02%	5.03%	5.02%	#DIV/0!	5.02%	5.02%	5.02%	5.02%

PART C

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
10	NOI After All Adjustments and Increase	$3,580,379 *							
11	Allocated on NOI Ratio	$3,580,379	$3,494	$1,725,917	$0	$1,725,917	$839,366	$682,280	$329,322
12	Final Rate Base After All Adjustments	$54,724,932 #							
13	Allocated on Rate Base Ratio	$54,724,932	$53,393	$26,380,078	$0	$26,380,078	$12,829,437	$10,428,432	$5,033,592
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	6.54%	6.54%	6.54%	#DIV/0!	6.54%	6.54%	6.54%	6.54%

*** Total from NCUC Form E-1, Item 45c, Page 9, Column 5, Line 20**
 # Total from NCUC Form E-1, Item 45c, Page 9, Column 5, Line 21

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 0.0000%
Demand 100.0000%

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
1	NOI (COS Sch 1, Ln 36)	$549,247	$512,852	$935	$0	$935	$0	$25,569	$9,891
2	NOI Ratio (Based on Ln 1)	100.0000%	93.3737%	0.1702%	0.0000%	0.1702%	0.0000%	4.6553%	1.8008%
3	Rate Base (COS Sch 1, Ln 38)	$32,464,901	$30,313,694	$55,238	$0	$55,238	$0	$1,511,324	$584,645
4	Rate Base Ratio (Based on Ln 3)	100.0000%	93.3737%	0.1701%	0.0000%	0.1701%	0.0000%	4.6553%	1.8009%
5	Rate of Return (Ln 1 / Ln 3)	1.69%	1.69%	1.69%	#DIV/0!	1.69%	#DIV/0!	1.69%	1.69%

PART B

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
6	Change in NOI (Item 45b, Pg 6, Col 2, Ln 20)	($14,647)							
7	Allocated on NOI Ratio (Ln 2)	($14,647)	($13,676)	($25)	$0	($25)	$0	($682)	($264)
8	Annualized NOI (Ln 1 + Ln 7)	$534,600	$499,176	$910	$0	$910	$0	$24,887	$9,627
9	Annualized Rate of Return (Ln 8 / Ln 3)	1.65%	1.65%	1.65%	#DIV/0!	1.65%	#DIV/0!	1.65%	1.65%

PART C

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
10	NOI After All Adjustments and Increase	$1,808,249 *							
11	Allocated on NOI Ratio	$1,808,248	$1,688,428	$3,078	$0	$3,078	$0	$84,179	$32,563
12	Final Rate Base After All Adjustments	$31,959,113 #							
13	Allocated on Rate Base Ratio	$31,959,113	$29,841,421	$54,377	$0	$54,377	$0	$1,487,778	$575,537
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	5.66%	5.66%	5.66%	#DIV/0!	5.66%	#DIV/0!	5.66%	5.66%

*** Total from NCUC Form E-1, Item 45c, Page 11, Column 5, Line 20**
 # Total from NCUC Form E-1, Item 45c, Page 11, Column 5, Line 21

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 0.0000%
Demand 100.0000%

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
1	NOI (COS Sch 1, Ln 36)	$11,593	$6,067	$2,907	$0	$2,907	$1,419	$810	$390
2	NOI Ratio (Based on Ln 1)	100.0000%	52.3333%	25.0755%	0.0000%	25.0755%	12.2401%	6.9870%	3.3641%
3	Rate Base (COS Sch 1, Ln 38)	$227,013	$118,809	$56,930	$0	$56,930	$27,786	$15,860	$7,628
4	Rate Base Ratio (Based on Ln 3)	100.0000%	52.3358%	25.0779%	0.0000%	25.0779%	12.2398%	6.9864%	3.3602%
5	Rate of Return (Ln 1 / Ln 3)	5.11%	5.11%	5.11%	#DIV/0!	5.11%	5.11%	5.11%	5.11%

PART B

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
6	Change in NOI (Item 45b, Pg 7, Col 2, Ln 20)	($2,284)							
7	Allocated on NOI Ratio (Ln 2)	($2,285)	($1,195)	($573)	$0	($573)	($280)	($160)	($77)
8	Annualized NOI (Ln 1 + Ln 7)	$9,309	$4,872	$2,334	$0	$2,334	$1,139	$650	$313
9	Annualized Rate of Return (Ln 8 / Ln 3)	4.10%	4.10%	4.10%	#DIV/0!	4.10%	4.10%	4.10%	4.10%

PART C

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
10	NOI After All Adjustments and Increase	$15,707 *							
11	Allocated on NOI Ratio	$15,707	$8,220	$3,939	$0	$3,939	$1,923	$1,097	$528
12	Final Rate Base After All Adjustments	$209,605 #							
13	Allocated on Rate Base Ratio	$209,604	$109,698	$52,564	$0	$52,564	$25,655	$14,644	$7,043
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	7.49%	7.49%	7.49%	#DIV/0!	7.49%	7.50%	7.49%	7.50%

*** Total from NCUC Form E-1, Item 45c, Page 13, Column 5, Line 20**
 # Total from NCUC Form E-1, Item 45c, Page 13, Column 5, Line 21

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 0.0000%
Demand 100.0000%

Ln		Total	Customer	Demand - Production - Demand	Demand - Production - Energy	Demand - Production - Combined	Demand - Transmission	Demand - Distribution	Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$192,922,198	$22,973,924	$54,275,452	($0)	$54,275,452	$18,748,587	$24,641,139	$72,283,096
2	NOI (COS Sch 1, Ln 36)	$41,461,656	$5,135,655	$18,550,526	($0)	$18,550,526	$9,119,038	$7,114,944	$1,541,493
3	NOI Ratio (Based on Ln 1)	100.0000%	12.3865%	44.7414%	0.0000%	44.7414%	21.9939%	17.1603%	3.7179%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($60,621,360)							($60,621,360)
5	Removal of Rider Revenues (on NOI Ratio)	($2,842,691)	($352,110)	($1,271,860)	$0	($1,271,860)	($625,219)	($487,814)	($105,688)
6	Removal of Facilities Charges (on NOI Ratio)	($96)	($12)	($43)	$0	($43)	($21)	($16)	($4)
7	Removal of Load Management (assigned to production)	$49		$49	$0	$49			
8	COS Per Books Base Rate Revenue	$129,458,100	$22,621,802	$53,003,598	($0)	$53,003,598	$18,123,347	$24,153,308	$11,556,045

PART B

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

Ln		Total	Customer	Demand - Production - Demand	Demand - Production - Energy	Demand - Production - Combined	Demand - Transmission	Demand - Distribution	Energy
9	Annualized Rate Revenue Adjustment	$2,985,398							
10	Allocated on NOI Ratio (Ln 3)	$2,985,398	$369,787	$1,335,709	($0)	$1,335,709	$656,606	$512,303	$110,993
11	Total Revenues (Ln 8 + Ln 10)	$132,443,498	$22,991,589	$54,339,307	($0)	$54,339,307	$18,779,953	$24,665,611	$11,667,038
12	Annualized Billing Units		1,296,996	1,520,481,017	1,520,481,017	1,520,481,017	1,520,481,017	1,520,481,017	1,520,481,017
13	Unit Costs based on Annualized Revenues		$17.73 per month	$0.035738 per kWh	$0.000000 per kWh	$0.035738 per kWh	$0.012351 per kWh	$0.016222 per kWh	$0.007673 per kWh

PART C

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

Ln		Total	Customer	Demand - Production - Demand	Demand - Production - Energy	Demand - Production - Combined	Demand - Transmission	Demand - Distribution	Energy
14	Fully Adjusted Rate Revenue Adjustment	11,085,819							
15	Allocated on NOI Ratio (Ln 3)	11,085,819	1,373,147	4,959,951	($0)	4,959,950	2,438,205	1,902,359	412,157
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$140,543,918	$23,994,949	$57,963,549	($0)	$57,963,549	$20,561,552	$26,055,667	$11,968,202
17	Fully Adjusted Billing Units		1,317,564	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840
18	Unit Costs based on Fully Adjusted Cost of Service		$18.21 per month	$0.035719 per kWh	$0.000000 per kWh	$0.035719 per kWh	$0.012671 per kWh	$0.016056 per kWh	$0.007375 per kWh

PART D

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

Ln		Total	Customer	Demand - Production - Demand	Demand - Production - Energy	Demand - Production - Combined	Demand - Transmission	Demand - Distribution	Energy
19	Proposed Rate Revenue Adjustment	$30,043,524							
20	Allocated on NOI Ratio (Ln 3)	$30,043,524	$3,721,346	$13,441,893	($0)	$13,441,893	$6,607,745	$5,155,558	$1,116,981
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$170,587,442	$27,716,295	$71,405,442	($1)	$71,405,442	$27,169,297	$31,211,226	$13,085,183
22	Fully Adjusted Billing Units		1,317,564	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840
23	Unit Costs based on Proposed Revenue Requirement		$21.04 per month	$0.044002 per kWh	$0.000000 per kWh	$0.044002 per kWh	$0.016743 per kWh	$0.019233 per kWh	$0.008064 per kWh

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 0.0000%
Demand 100.0000%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$82,094,139	$5,259,940	$20,549,032	$0	$20,549,032	$7,432,260	$13,153,903	$35,699,004
2	NOI (COS Sch 1, Ln 36)	$17,899,224	$1,244,031	$7,974,098	$0	$7,974,098	$3,905,862	$3,807,743	$967,490
3	NOI Ratio (Based on Ln 1)	100.0000%	6.9502%	44.5500%	0.0000%	44.5500%	21.8214%	21.2732%	5.4052%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($29,697,669)							($29,697,669)
5	Removal of Rider Revenues (on NOI Ratio)	($1,325,418)	($92,119)	($590,473)	$0	($590,473)	($289,225)	($281,959)	($71,642)
6	Removal of Facilities Charges (on NOI Ratio)	($616,355)	($42,838)	($274,586)	$0	($274,586)	($134,497)	($131,119)	($33,315)
7	Removal of Load Management (assigned to production)	$16		$16	$0	$16			
8	COS Per Books Base Rate Revenue	$50,454,714	$5,124,983	$19,683,989	$0	$19,683,989	$7,008,538	$12,740,825	$5,896,379

PART B

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
9	Annualized Rate Revenue Adjustment	($981,351)							
10	Allocated on NOI Ratio (Ln 3)	($981,351)	($68,206)	($437,191)	$0	($437,191)	($214,144)	($208,765)	($53,044)
11	Total Revenues (Ln 8 + Ln 10)	$49,473,363	$5,056,777	$19,246,798	$0	$19,246,798	$6,794,393	$12,532,060	$5,843,334
12	Annualized Billing Units		217,116	745,580,278	745,580,278	745,580,278	745,580,278	745,580,278	745,580,278
13	Unit Costs based on Annualized Revenues		$23.29 per month	$0.025815 per kWh	$0.000000 per kWh	$0.025815 per kWh	$0.009113 per kWh	$0.016808 per kWh	$0.007837 per kWh

PART C

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
14	Fully Adjusted Rate Revenue Adjustment	$16,292							
15	Allocated on NOI Ratio (Ln 3)	$16,292	$1,132	$7,258	$0	$7,258	$3,555	$3,466	$881
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$50,471,007	$5,126,115	$19,691,248	$0	$19,691,248	$7,012,093	$12,744,291	$5,897,259
17	Fully Adjusted Billing Units		221,052	761,872,918	761,872,918	761,872,918	761,872,918	761,872,918	761,872,918
18	Unit Costs based on Fully Adjusted Cost of Service		$23.19 per month	$0.025846 per kWh	$0.000000 per kWh	$0.025846 per kWh	$0.009204 per kWh	$0.016728 per kWh	$0.007740 per kWh

PART D

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
19	Proposed Rate Revenue Adjustment	$12,973,749							
20	Allocated on NOI Ratio (Ln 3)	$12,973,749	$901,701	$5,779,801	$0	$5,779,801	$2,831,054	$2,759,935	$701,258
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$63,444,756	$6,027,816	$25,471,048	$0	$25,471,048	$9,843,147	$15,504,227	$6,598,517
22	Fully Adjusted Billing Units		221,052	761,872,918	761,872,918	761,872,918	761,872,918	761,872,918	761,872,918
23	Unit Costs based on Proposed Revenue Requirement		$27.27 per month	$0.033432 per kWh	$0.000000 per kWh	$0.033432 per kWh	$0.012920 per kWh	$0.020350 per kWh	$0.008661 per kWh

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 0.0000%
Demand 100.0000%

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$53,092,030	$141,918	$13,267,428	$0	$13,267,428	$5,193,388	$6,554,561	$27,934,735
2	NOI (COS Sch 1, Ln 36)	$13,281,442	$47,623	$6,368,208	$0	$6,368,208	$3,078,475	$2,562,645	$1,224,491
3	NOI Ratio (Based on Ln 1)	100.0000%	0.3586%	47.9482%	0.0000%	47.9482%	23.1788%	19.2949%	9.2196%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($22,690,325)							($22,690,325)
5	Removal of Rider Revenues (on NOI Ratio)	($436,077)	($1,564)	($209,091)	$0	($209,091)	($101,077)	($84,141)	($40,204)
6	Removal of Facilities Charges (on NOI Ratio)	($418,566)	($1,501)	($200,695)	$0	($200,695)	($97,018)	($80,762)	($38,590)
7	Removal of Load Management (assigned to production)	$8		$8	$0	$8			
8	COS Per Books Base Rate Revenue	$29,547,071	$138,854	$12,857,650	$0	$12,857,650	$4,995,292	$6,389,658	$5,165,616

PART B

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
9	Annualized Rate Revenue Adjustment	($3,832,401)							
10	Allocated on NOI Ratio (Ln 3)	($3,832,401)	($13,742)	($1,837,566)	$0	($1,837,566)	($888,303)	($739,459)	($353,331)
11	Total Revenues (Ln 8 + Ln 10)	$25,714,670	$125,112	$11,020,084	$0	$11,020,084	$4,106,989	$5,650,199	$4,812,286
12	Annualized Billing Units		660	1,248,843	572,194,905	1,248,843	1,349,735	1,349,735	572,194,905
13	Unit Costs based on Annualized Revenues		$189.56	$8.824235	$0.000000	$8.824235	$3.042811	$4.186155	$0.008410
			per month	per kW	per kWh	per kW	per kW	per kW	per kWh

PART C

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
14	Fully Adjusted Rate Revenue Adjustment	($4,374,050)							
15	Allocated on NOI Ratio (Ln 3)	($4,374,050)	($15,684)	($2,097,277)	$0	($2,097,277)	($1,013,851)	($843,970)	($403,268)
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$25,173,021	$123,170	$10,760,374	$0	$10,760,374	$3,981,441	$5,545,688	$4,762,348
17	Fully Adjusted Billing Units		672	1,228,152	562,714,493	1,228,152	1,327,372	1,327,372	562,714,493
18	Unit Costs based on Fully Adjusted Cost of Service		$183.29	$8.761435	$0.000000	$8.761435	$2.999492	$4.177946	$0.008463
			per month	per kW	per kWh	per kW	per kW	per kW	per kWh

PART D

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
19	Proposed Rate Revenue Adjustment	$5,414,139							
20	Allocated on NOI Ratio (Ln 3)	$5,414,139	$19,413	$2,595,980	$0	$2,595,980	$1,254,931	$1,044,654	$499,160
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$30,587,160	$142,583	$13,356,354	$0	$13,356,354	$5,236,372	$6,590,343	$5,261,508
22	Fully Adjusted Billing Units		672	1,228,152	562,714,493	1,228,152	1,327,372	1,327,372	562,714,493
23	Unit Costs based on Proposed Revenue Requirement		$212.18	$10.875164	$0.000000	$10.875164	$3.944917	$4.964955	$0.009350
			per month	per kW	per kWh	per kW	per kW	per kW	per kWh

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 0.0000%
Demand 100.0000%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$47,382,204	$20,142	$8,580,429	$0	$8,580,429	$3,423,703	$0	$35,357,930
2	NOI (COS Sch 1, Ln 36)	$8,766,794	$7,999	$4,573,530	$0	$4,573,530	$2,137,192	$0	$2,048,073
3	NOI Ratio (Based on Ln 1)	100.0000%	0.0912%	52.1688%	0.0000%	52.1688%	24.3783%	0.0000%	23.3617%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($28,135,491)							($28,135,491)
5	Removal of Rider Revenues (on NOI Ratio)	$0	$0	$0	$0	$0	$0	$0	$0
6	Removal of Facilities Charges (on NOI Ratio)	($7,479)	($7)	($3,902)	$0	($3,902)	($1,823)	$0	($1,747)
7	Removal of Load Management (assigned to production)	$4		$4	$0	$4			
8	COS Per Books Base Rate Revenue	$19,239,238	$20,135	$8,576,531	$0	$8,576,531	$3,421,880	$0	$7,220,692

PART B

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
9	Annualized Rate Revenue Adjustment	$566,062							
10	Allocated on NOI Ratio (Ln 3)	$566,062	$516	$295,308	$0	$295,308	$137,996	$0	$132,242
11	Total Revenues (Ln 8 + Ln 10)	$19,805,301	$20,652	$8,871,839	$0	$8,871,839	$3,559,876	$0	$7,352,934
12	Annualized Billing Units		12	2,037,077	657,936,799	657,936,799	2,037,077	2,037,077	657,936,799
13	Unit Costs based on Annualized Revenues		$1,720.97	$4.355181	$0.000000	$0.013484	$1.747541	$0.000000	$0.011176
			per month	per kW	per kWh	per kWh	per kW	per kW	per kWh

PART C

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
14	Fully Adjusted Rate Revenue Adjustment	$2,783,416							
15	Allocated on NOI Ratio (Ln 3)	$2,783,416	$2,540	$1,452,074	$0	$1,452,074	$678,548	$0	$650,254
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$22,022,654	$22,675	$10,028,606	$0	$10,028,606	$4,100,428	$0	$7,870,946
17	Fully Adjusted Billing Units		12	2,265,143	731,597,816	731,597,816	2,265,143	2,265,143	731,597,816
18	Unit Costs based on Fully Adjusted Cost of Service		$1,889.57	$4.427361	$0.000000	$0.013708	$1.810229	$0.000000	$0.010759
			per month	per kW	per kWh	per kWh	per kW	per kW	per kWh

PART D

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
19	Proposed Rate Revenue Adjustment	$4,460,689							
20	Allocated on NOI Ratio (Ln 3)	$4,460,689	$4,070	$2,327,087	$0	$2,327,087	$1,087,438	$0	$1,042,093
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$26,483,343	$26,745	$12,355,693	$0	$12,355,693	$5,187,867	$0	$8,913,039
22	Fully Adjusted Billing Units		12	2,265,143	731,597,816	731,597,816	2,265,143	2,265,143	731,597,816
23	Unit Costs based on Proposed Revenue Requirement		$2,228.74	$5.454708	$0.000000	$0.016889	$2.290304	$0.000000	$0.012183
			per month	per kW	per kWh	per kWh	per kW	per kW	per kWh

PART A

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 0.0000%
Demand 100.0000%

		Total	Customer	Demand - Production - Demand	Demand - Production - Energy	Demand - Production - Combined	Demand - Transmission	Demand - Distribution	Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$21,960,946	$15,638	$5,198,626	$0	$5,198,626	$1,967,051	$2,413,421	$12,366,210
2	NOI (COS Sch 1, Ln 36)	$4,733,302	$4,619	$2,281,682	$0	$2,281,682	$1,109,651	$901,982	$435,368
3	NOI Ratio (Based on Ln 1)	100.0000%	0.0976%	48.2049%	0.0000%	48.2049%	23.4435%	19.0561%	9.1980%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($10,169,761)							($10,169,761)
5	Removal of Rider Revenues (on NOI Ratio)	($223)	($0)	($108)	$0	($108)	($52)	($43)	($21)
6	Removal of Facilities Charges (on NOI Ratio)	($222,433)	($217)	($107,224)	$0	($107,224)	($52,146)	($42,387)	($20,459)
7	Removal of Load Management (assigned to production)	$4		$4	$0	$4			
8	COS Per Books Base Rate Revenue	$11,568,532	$15,421	$5,091,298	$0	$5,091,298	$1,914,853	$2,370,991	$2,175,969

PART B

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

		Total	Customer	Demand - Production - Demand	Demand - Production - Energy	Demand - Production - Combined	Demand - Transmission	Demand - Distribution	Energy
9	Annualized Rate Revenue Adjustment	($1,984,819)							
10	Allocated on NOI Ratio (Ln 3)	($1,984,819)	($1,937)	($956,779)	$0	($956,779)	($465,311)	($378,229)	($182,563)
11	Total Revenues (Ln 8 + Ln 10)	$9,583,714	$13,484	$4,134,519	$0	$4,134,519	$1,449,542	$1,992,763	$1,993,406
12	Annualized Billing Units		36	96,466,999	159,019,895	255,486,894	636,467	636,467	255,486,894
13	Unit Costs based on Annualized Revenues		$374.55 per month	$0.042859 per kWh	$0.000000 per kWh	$0.016183 per kWh	$2.277482 per kW	$3.130976 per kW	$0.007802 per kWh

PART C

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

		Total	Customer	Demand - Production - Demand	Demand - Production - Energy	Demand - Production - Combined	Demand - Transmission	Demand - Distribution	Energy
14	Fully Adjusted Rate Revenue Adjustment	($1,743,878)							
15	Allocated on NOI Ratio (Ln 3)	($1,743,878)	($1,702)	($840,634)	$0	($840,634)	($408,826)	($332,315)	($160,401)
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$9,824,654	$13,719	$4,250,664	$0	$4,250,664	$1,506,027	$2,038,677	$2,015,568
17	Fully Adjusted Billing Units		36	98,893,555	163,019,923	261,913,478	652,477	652,477	261,913,478
18	Unit Costs based on Fully Adjusted Cost of Service		$381.08 per month	$0.042982 per kWh	$0.000000 per kWh	$0.016229 per kWh	$2.308168 per kW	$3.124519 per kW	$0.007696 per kWh

PART D

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

		Total	Customer	Demand - Production - Demand	Demand - Production - Energy	Demand - Production - Combined	Demand - Transmission	Demand - Distribution	Energy
19	Proposed Rate Revenue Adjustment	$1,990,617							
20	Allocated on NOI Ratio (Ln 3)	$1,990,617	$1,943	$959,575	$0	$959,575	$466,670	$379,334	$183,097
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$11,815,272	$15,662	$5,210,239	$0	$5,210,239	$1,972,697	$2,418,010	$2,198,664
22	Fully Adjusted Billing Units		36	98,893,555	163,019,923	261,913,478	652,477	652,477	261,913,478
23	Unit Costs based on Proposed Revenue Requirement		$435.04 per month	$0.052685 per kWh	$0.000000 per kWh	$0.019893 per kWh	$3.023397 per kW	$3.705894 per kW	$0.008395 per kWh

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 0.0000%
Demand 100.0000%

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$6,091,376	$4,845,512	$900	$0	$900	$0	$175,553	$1,069,411
2	NOI (COS Sch 1, Ln 36)	$549,247	$512,852	$935	$0	$935	$0	$25,569	$9,891
3	NOI Ratio (Based on Ln 1)	100.0000%	93.3737%	0.1702%	0.0000%	0.1702%	0.0000%	4.6553%	1.8008%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($913,313)							($913,313)
5	Removal of Rider Revenues (on NOI Ratio)	$0	$0	$0	$0	$0	$0	$0	$0
6	Removal of Facilities Charges (on NOI Ratio)	$0	$0	$0	$0	$0	$0	$0	$0
7	Removal of Load Management (assigned to production)	$0		$0	$0	$0			
8	COS Per Books Base Rate Revenue	$5,178,063	$4,845,512	$900	$0	$900	$0	$175,553	$156,098

PART B

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
9	Annualized Rate Revenue Adjustment	($21,320)							
10	Allocated on NOI Ratio (Ln 3)	($21,320)	($19,907)	($36)	$0	($36)	$0	($992)	($384)
11	Total Revenues (Ln 8 + Ln 10)	$5,156,743	$4,825,605	$864	$0	$864	$0	$174,561	$155,714
12	Annualized Billing Units		347,796	21,480,264	21,480,264	21,480,264	21,480,264	21,480,264	21,480,264
13	Unit Costs based on Annualized Revenues		$13.87 per month	$0.000040 per kWh	$0.000000 per kWh	$0.000040 per kWh	$0.000000 per kWh	$0.008127 per kWh	$0.007249 per kWh

PART C

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
14	Fully Adjusted Rate Revenue Adjustment	$72,663							
15	Allocated on NOI Ratio (Ln 3)	$72,663	$67,848	$124	$0	$124	$0	$3,383	$1,309
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$5,250,726	$4,913,360	$1,024	$0	$1,024	$0	$178,936	$157,407
17	Fully Adjusted Billing Units		318,276	19,657,087	19,657,087	19,657,087	19,657,087	19,657,087	19,657,087
18	Unit Costs based on Fully Adjusted Cost of Service		$15.44 per month	$0.000052 per kWh	$0.000000 per kWh	$0.000052 per kWh	$0.000000 per kWh	$0.009103 per kWh	$0.008008 per kWh

PART D

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
19	Proposed Rate Revenue Adjustment	$2,067,260							
20	Allocated on NOI Ratio (Ln 3)	$2,067,260	$1,930,277	$3,519	$0	$3,519	$0	$96,237	$37,228
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$7,317,987	$6,843,637	$4,543	$0	$4,543	$0	$275,173	$194,634
22	Fully Adjusted Billing Units		318,276	19,657,087	19,657,087	19,657,087	19,657,087	19,657,087	19,657,087
23	Unit Costs based on Proposed Revenue Requirement		$21.50 per month	$0.000231 per kWh	$0.000000 per kWh	$0.000231 per kWh	$0.000000 per kWh	$0.013999 per kWh	$0.009901 per kWh

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 0.0000%
Demand 100.0000%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$67,604	$35,058	$7,779	$0	$7,779	$2,766	$2,551	$19,450
2	NOI (COS Sch 1, Ln 36)	$11,593	$6,067	$2,907	$0	$2,907	$1,419	$810	$390
3	NOI Ratio (Based on Ln 1)	100.0000%	52.3333%	25.0755%	0.0000%	25.0755%	12.2401%	6.9870%	3.3641%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($16,290)							($16,290)
5	Removal of Rider Revenues (on NOI Ratio)	$0	$0	$0	$0	$0	$0	$0	$0
6	Removal of Facilities Charges (on NOI Ratio)	$0	$0	$0	$0	$0	$0	$0	$0
7	Removal of Load Management (assigned to production)	$0		$0	$0	$0			
8	COS Per Books Base Rate Revenue	$51,314	$35,058	$7,779	$0	$7,779	$2,766	$2,551	$3,160

PART B

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
9	Annualized Rate Revenue Adjustment	($3,109)							
10	Allocated on NOI Ratio (Ln 3)	($3,109)	($1,627)	($780)	$0	($780)	($381)	($217)	($105)
11	Total Revenues (Ln 8 + Ln 10)	$48,204	$33,431	$6,999	$0	$6,999	$2,385	$2,334	$3,055
12	Annualized Billing Units		2,340	465,629	465,629	465,629	465,629	465,629	465,629
13	Unit Costs based on Annualized Revenues		$14.29	$0.015032	$0.000000	$0.015032	$0.005123	$0.005012	$0.006562
			per month	per kWh	per kWh	per kWh	per kWh	per kWh	per kWh

PART C

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
14	Fully Adjusted Rate Revenue Adjustment	($352)							
15	Allocated on NOI Ratio (Ln 3)	($352)	($184)	($88)	$0	($88)	($43)	($25)	($12)
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$50,962	$34,874	$7,691	$0	$7,691	$2,723	$2,526	$3,148
17	Fully Adjusted Billing Units		2,352	513,499	513,499	513,499	513,499	513,499	513,499
18	Unit Costs based on Fully Adjusted Cost of Service		$14.83	$0.014977	$0.000000	$0.014977	$0.005303	$0.004920	$0.006131
			per month	per kWh	per kWh	per kWh	per kWh	per kWh	per kWh

PART D

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
19	Proposed Rate Revenue Adjustment	$11,468							
20	Allocated on NOI Ratio (Ln 3)	$11,468	$6,002	$2,876	$0	$2,876	$1,404	$801	$386
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$62,430	$40,875	$10,566	$0	$10,566	$4,127	$3,328	$3,534
22	Fully Adjusted Billing Units		2,352	513,499	513,499	513,499	513,499	513,499	513,499
23	Unit Costs based on Proposed Revenue Requirement		$17.38	$0.020577	$0.000000	$0.020577	$0.008036	$0.006480	$0.006882
			per month	per kWh	per kWh	per kWh	per kWh	per kWh	per kWh

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023

SCHEDULE 1

SCHEDULE 1 - SUMMARY

Line #		NC Jur Total	Residential	SGS,CO & Muni	LGS	Schedule NS	6VP	St & Outdoor Lighting	Traffic Lighting	Allocation Basis
1	Dec 2023									
2										
3	C:[SUMMARY OF RESULTS]									
4	D:[]									
5	E:[OPERATING REVENUES]	408,196,365	195,275,807	82,960,622	53,558,478	47,906,007	22,189,117	6,237,218	69,116	NC Class Schedule 2 - Revenue/Lir
6	F:[]									
7	G:[OPERATING EXPENSES]									
8	H:[OPERATION & MAINTENANCE EXPENSES]	239,139,128	102,053,293	48,545,778	31,708,510	38,354,770	14,812,426	3,621,843	42,508	NC Class Schedule 3 - O&M Expen
9	I:[DEPRECIATION EXPENSE]	60,832,913	31,284,751	12,256,625	5,475,821	6,406,345	3,034,425	2,363,869	11,078	NC Class Schedule 4 - Depreciatio
10	J:[AMORT. OF ACQ. AJUSTMENTS]	7,311	3,152	1,500	823	1,290	504	43	1	NC Class Schedule 4 - Depreciatio
11	K:[AMORT. OF PROP. LOSS & REG STUDY]	83,583	36,031	17,145	9,411	14,744	5,759	487	6	NC Class Schedule 6 - Net Current
12	L:[REGULATORY DEBITS AND CREDITS]	10,909,089	4,560,194	2,194,125	1,386,199	1,960,781	742,515	64,319	957	NC Class Schedule 6 - Net Current
13	N:[GAIN/LOSS ON DISPOSITION OF ALLOWANCES]	(89,091)	(35,475)	(17,379)	(13,278)	(16,464)	(5,951)	(534)	(10)	NC Class Schedule 6 - Net Current
14	O:[GAIN / LOSS ON DISPOSITION OF PROPERTY]	245,242	123,968	49,820	23,491	27,996	12,971	6,958	37	NC Class Schedule 6 - Net Current
15	Q:[ACCRETION EXPENSE - ARO]	5,133,919	2,072,158	1,010,097	735,151	942,085	344,785	29,055	587	NC Class Schedule 22 - Other Alloc
16	R:[FEDERAL INCOME TAX]									
17	S:[INVESTMENT TAX CREDIT - AMORTIZATION]	141,040	60,800	28,930	15,881	24,880	9,717	822	11	NC Class Schedule 7 - Income Tax
18	T:[FEDERAL NET CURRENT TAX]	6,833,874	5,023,183	1,346,297	2,088,043	(1,297,621)	6,399	(333,554)	1,127	NC Class Schedule 6 - Net Current
19	U:[FEDERAL INCOME TAX DEFERRED]	(3,208,237)	(1,210,464)	(574,652)	(689,749)	(531,046)	(192,308)	(9,562)	(455)	NC Class Schedule 7 - Income Tax
20	W:[STATE INCOME TAX CURRENT]	483,103	367,371	100,319	112,707	(85,134)	2,115	(14,356)	81	NC Class Schedule 6 - Net Current
21	X:[STATE INCOME TAX DEFERRED]	1,812,324	1,378,164	376,339	422,812	(319,374)	7,935	(53,854)	302	NC Class Schedule 7 - Income Tax
22	Y:[TAXES OTHER THAN INCOME TAX]	12,635,649	6,410,309	2,581,589	1,187,636	1,426,215	664,757	363,021	2,122	NC Class Schedule 5 - Other Taxes
23	Z:[TOTAL ELECTRIC OPERATING EXPENSES]	334,959,847	152,127,435	67,916,531	42,463,459	46,909,467	19,446,047	6,038,556	58,352	
24	AA:[]									
25	AB:[NET OPERATING INCOME]	73,236,518	43,148,372	15,044,091	11,095,020	996,540	2,743,070	198,661	10,764	
26	AC:[]									
27	AD:[ADJUSTMENTS TO OPERATING INCOME]									
28	AE:[ADD: ALLOWANCE FOR FUNDS]	14,108,009	6,172,568	2,890,087	1,573,125	2,408,710	950,921	111,447	1,150	NC Class Schedule 8 - Other Adjus
29	AF:[]									
30	AG:[DEDUCT: CHARITABLE & EDUCATIONAL]									
31	AH:[DONATIONS]	397,631	169,690	80,720	52,724	63,775	24,630	6,022	71	NC Class Schedule 8 - Other Adjus
32	AI:[DONATIONS - ASSIGNED]	0	0	0	0	0	0	0	0	NC Class Schedule 8 - Other Adjus
33	AJ:[INTEREST EXPENSE - CUST. DEPOSITS]	31,017	14,826	6,309	4,080	3,641	1,688	468	5	NC Class Schedule 8 - Other Adjus
34	AK:[OTHER INTEREST EXPENSE]	212,619	104,196	43,376	21,135	26,571	12,019	5,291	31	NC Class Schedule 8 - Other Adjus
35	AL:[TOTAL DEDUCTIONS]	641,268	288,713	130,405	77,939	93,987	38,336	11,782	106	
36	AM:[]									
37	AN:[ADJUSTED NET ELEC. OPERATING INCOME]	86,703,259	49,032,227	17,803,773	12,590,205	3,311,263	3,655,655	298,327	11,808	
38	AO:[]									
39	AP:[RATE BASE]	1,594,851,513	775,661,985	325,326,317	161,595,895	202,505,925	91,027,589	38,511,976	221,826	NC Class Schedule 1 - Summary/Li
40	AQ:[]									
41	AR:[ROR EARNED ON RATE BASE (Including Ringfenced as applic	5.4364%	6.3213%	5.4726%	7.7912%	1.6351%	4.0160%	0.7746%	5.3233%	
42	AS:[]									
43	AV:[SYSTEM RATE OF RETURN (Excluding Ringfenced as applicat	5.4364%	5.4364%	5.4364%	5.4364%	5.4364%	5.4364%	5.4364%	5.4364%	
44	AW:[INDEX RATE OF RETURN (PRESENT) (AQ/AU)]	1.00	1.16	1.01	1.43	0.30	0.74	0.14	0.98	
45	AX:[]									

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023

SCHEDULE 1 - SUMMARY

Line #		NC Jur Total	Residential	SGS,CO & Muni	LGS	Schedule NS	6VP	St & Outdoor Lighting	Traffic Lighting	Allocation Basis
46	AY:[]									
47	AZ:[]									
48	BA:[RATE BASE]									
49	BB:[PLANT INVESTMENT]									
50	BC:[ELECTRIC PLANT INCL. NUCLEAR FUEL]	2,269,147,992	1,147,036,872	460,968,449	217,357,669	259,043,128	120,015,180	64,380,718	345,977	NC Class Schedule 10 - Plant in Ser
51	BD:[ACQUISITION ADJUSTMENTS]	313,057	134,953	64,215	35,249	55,224	21,569	1,824	23	NC Class Schedule 10 - Plant in Ser
52	BE:[ELECTRIC CWIP INCL FUEL]	360,345,332	161,220,411	73,300,660	40,388,683	58,202,066	23,249,968	3,949,813	33,730	NC Class Schedule 12 - Constructic
53	BF:[PLANT HELD FOR FUTURE USE]	0	0	0	0	0	0	0	0	NC Class Schedule 13 - Plant Held
54	BG:[TOTAL PLANT INVESTMENT]	2,629,806,381	1,308,392,236	534,333,324	257,781,601	317,300,418	143,286,717	68,332,356	379,730	
55	BH:[]									
56	BI:[DEDUCT:]									
57	BJ:[ACCUM. PROV. FOR DEPREC. & AMORT]	(778,067,179)	(406,025,171)	(157,061,948)	(70,952,040)	(82,575,882)	(38,041,837)	(23,294,570)	(115,731)	NC Class Schedule 11 - Accum Dep
58	BK:[AMORT OF NUCLEAR FUEL]	(55,694,591)	(22,176,751)	(10,864,121)	(8,300,666)	(10,292,639)	(3,720,343)	(334,112)	(5,959)	NC Class Schedule 11 - Accum Dep
59	BL:[ACQUISITION ADJ. FOR DEPREC. RESERVE]	(53,457)	(23,044)	(10,965)	(6,019)	(9,430)	(3,683)		(312)	NC Class Schedule 11 - Accum Dep
60	BM:[TOTAL DEPRECIATION & AMORTIZATION]	(833,815,226)	(428,224,966)	(167,937,034)	(79,258,725)	(92,877,951)	(41,765,863)	(23,628,994)	(4)(121,694)	
61	BN:[]									
62	BO:[NET PLANT]	1,795,991,155	880,167,270	366,396,290	178,522,876	224,422,467	101,520,855	44,703,362	258,035	
63	BP:[]									
64	BQ:[DEDUCT:]									
65	BS:[ACCUMULATED DEFERRED INCOME TAXES]	185,445,996	87,971,837	37,257,798	20,470,296	25,054,747	10,600,906	4,064,621	25,792	NC Class Schedule 23 - Cost Free C
67	BW:[CUSTOMER DEPOSITS]	3,135,948	1,498,955	637,850	412,511	368,147	170,631	47,328	525	NC Class Schedule 14 - Working Ca
68	BX:[EXCESS DEFERRED INCOME TAXES]	107,582,689	54,338,878	21,931,195	10,223,599	12,338,039	5,734,463	3,001,329	15,185	NC Class Schedule 23 - Cost Free C
69	BY:[]									
70	BZ:[ADD: WORKING CAPITAL]									
71	CA:[MATERIAL & SUPPLIES]	50,733,308	23,213,982	10,195,017	5,906,077	7,486,650	3,050,898	874,623	6,062	NC Class Schedule 14 - Working Ca
73	CC:[INVESTOR FUNDS ADVANCED]	15,791,563	7,556,586	3,209,551	2,071,911	1,851,256	857,984	241,599	2,676	NC Class Schedule 14 - Working Ca
74	CD:[TOTAL ADDITIONS]	264,540,117	108,752,402	52,198,160	36,851,760	47,212,224	17,502,672	1,994,941	27,957	NC Class Schedule 14 - Working Ca
78	CH:[TOTAL DEDUCTIONS]	(236,039,996)	(100,218,584)	(46,845,857)	(30,650,323)	(40,705,739)	(15,398,820)	(2,189,270)	(31,403)	NC Class Schedule 14 - Working Ca
80	CJ:[DEFERRED FUEL]	0	0	0	0	0	0	0	0	NC Class Schedule 14 - Working Ca
82	CL:[TOTAL ALLOWANCE FOR WORK CAPITAL]	95,024,991	39,304,386	18,756,870	14,179,425	15,844,391	6,012,734	921,893	5,292	
83	CM:[]									
84	CN:[TOTAL RATE BASE]	1,594,851,513	775,661,985	325,326,317	161,595,895	202,505,925	91,027,589	38,511,976	221,826	
85	CO:[]									

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**Residential Class** **Annualized Cost of Service Summary** DESCRIPTION	(1) Residential Cost of Service	(2) Annualized Revenue Adjustment	(3) Residential Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$129,458,161	$2,963,574	$132,421,735
2	Forfeited Discounts and Miscellaneous Service Revenues	$761,746	$5,147	$766,892
3	Non-Fuel Rider Revenues	$2,842,691	$0	$2,842,691
4	Fuel Revenues	$60,621,360	$0	$60,621,360
5	Other Operating Revenues	$1,591,849	$0	$1,591,849
6	TOTAL OPERATING REVENUES	$195,275,807	$2,968,721	$198,244,528
	OPERATING EXPENSES			
7	Fuel Expense	$61,522,679		$61,522,679
8	Non-Fuel Operating and Maintenance Expense	$40,530,614	$21,622	$40,552,236
9	Depreciation and Amortization	$37,956,286		$37,956,286
10	Federal Income Tax	$3,873,519	$582,354	$4,455,872
11	State Income Tax	$1,745,535	$169,640	$1,915,175
12	Taxes Other than Income Tax	$6,410,309	$4,347	$6,414,656
13	(Gain)/Loss on Disposition of Property	$88,493		$88,493
14	TOTAL ELECTRIC OPERATING EXPENSES	$152,127,435	$777,962	$152,905,398
15	**NET OPERATING INCOME**	$43,148,372	$2,190,759	$45,339,130
	ADJUSTMENTS TO OPERATING INCOME			
16	*ADD:* AFUDC	$6,172,568		$6,172,568
17	*LESS:* Charitable Donations	$169,690		$169,690
18	Interest Expense on Customer Deposits	$14,826		$14,826
19	Other Interest Expense/(Income)	$104,196		$104,196
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$49,032,227	$2,190,759	$51,222,986
21	**RATE BASE (from Line 38 below)**	$775,661,985	$0	$775,661,985
22	**ROR EARNED ON AVERAGE RATE BASE**	6.3213%		6.6038%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$23,213,982		$23,213,982
24	Investor Funds Advanced	$7,556,586		$7,556,586
25	Total Additions	$108,752,402		$108,752,402
26	Total Deductions	($100,218,584)		($100,218,584)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$39,304,386	$0	$39,304,386
	NET UTILITY PLANT			
28	Utility Plant in Service	$1,147,036,872		$1,147,036,872
29	Acquisition Adjustments	$134,953		$134,953
30	Construction Work in Progress	$161,220,411		$161,220,411
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$428,201,921		$428,201,921
32	Provision for Acquisition Adjustments	$23,044		$23,044
33	TOTAL NET UTILITY PLANT	$880,167,270	$0	$880,167,270
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$1,498,955		$1,498,955
35	Accumulated Deferred Income Taxes	$87,971,837		$87,971,837
36	Other Cost Free Capital	$54,338,878		$54,338,878
37	TOTAL RATE BASE DEDUCTIONS	$143,809,671	$0	$143,809,671
38	**TOTAL RATE BASE**	$775,661,985	$0	$775,661,985

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**SGS & Public Authorities Class** **Annualized Cost of Service Summary** DESCRIPTION	(1) SGS Cost of Service	(2) Annualized Revenue Adjustment	(3) SGS Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$51,071,052	($989,270)	$50,081,782
2	Forfeited Discounts and Miscellaneous Service Revenues	$210,233	$2,190	$212,423
3	Non-Fuel Rider Revenues	$1,325,418	$0	
4	Fuel Revenues	$29,697,669	$0	$29,697,669
5	Other Operating Revenues	$656,251	$0	$656,251
6	TOTAL OPERATING REVENUES	$82,960,622	($987,080)	$81,973,542
	OPERATING EXPENSES			
7	Fuel Expense	$30,139,214		$30,139,214
8	Non-Fuel Operating and Maintenance Expense	$18,406,564	($7,189)	$18,399,375
9	Depreciation and Amortization	$15,479,490		$15,479,490
10	Federal Income Tax	$800,575	($193,629)	$606,946
11	State Income Tax	$476,658	($56,404)	$420,254
12	Taxes Other than Income Tax	$2,581,589	($1,445)	$2,580,143
13	(Gain)/Loss on Disposition of Property	$32,441		$32,441
14	TOTAL ELECTRIC OPERATING EXPENSES	$67,916,531	($258,667)	$67,657,864
15	**NET OPERATING INCOME**	$15,044,091	($728,413)	$14,315,678
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$2,890,087		$2,890,087
17	LESS: Charitable Donations	$80,720		$80,720
18	Interest Expense on Customer Deposits	$6,309		$6,309
19	Other Interest Expense/(Income)	$43,376		$43,376
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$17,803,773	($728,413)	$17,075,360
21	**RATE BASE (from Line 38 below)**	$325,326,317	$0	$325,326,317
22	**ROR EARNED ON AVERAGE RATE BASE**	5.4726%		5.2487%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$10,195,017		$10,195,017
24	Investor Funds Advanced	$3,209,551		$3,209,551
25	Total Additions	$52,198,160		$52,198,160
26	Total Deductions	($46,845,857)		($46,845,857)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$18,756,870	$0	$18,756,870
	NET UTILITY PLANT			
28	Utility Plant in Service	$460,968,449		$460,968,449
29	Acquisition Adjustments	$64,215		$64,215
30	Construction Work in Progress	$73,300,660		$73,300,660
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$167,926,069		$167,926,069
32	Provision for Acquisition Adjustments	$10,965		$10,965
33	TOTAL NET UTILITY PLANT	$366,396,290	$0	$366,396,290
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$637,850		$637,850
35	Accumulated Deferred Income Taxes	$37,257,798		$37,257,798
36	Other Cost Free Capital	$21,931,195		$21,931,195
37	TOTAL RATE BASE DEDUCTIONS	$59,826,843	$0	$59,826,843
38	**TOTAL RATE BASE**	$325,326,317	$0	$325,326,317

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**LGS Class** **Annualized Cost of Service Summary** DESCRIPTION	(1) LGS Cost of Service	(2) Annualized Revenue Adjustment	(3) LGS Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load			
1	Management	$29,965,629	($3,799,352)	$26,166,277
2	Forfeited Discounts and Miscellaneous Service Revenues	$88,823	$1,416	$90,240
3	Non-Fuel Rider Revenues	$436,077	$0	
4	Fuel Revenues	$22,690,325	$0	$22,690,325
5	Other Operating Revenues	$377,625	$0	$377,625
6	TOTAL OPERATING REVENUES	$53,558,478	($3,797,935)	$49,760,543
	OPERATING EXPENSES			
7	Fuel Expense	$23,027,685		$23,027,685
8	Non-Fuel Operating and Maintenance Expense	$8,680,825	($27,661)	$8,653,164
9	Depreciation and Amortization	$7,607,405		$7,607,405
10	Federal Income Tax	$1,414,175	($745,015)	$669,161
11	State Income Tax	$535,519	($217,024)	$318,495
12	Taxes Other than Income Tax	$1,187,636	($5,561)	$1,182,075
13	(Gain)/Loss on Disposition of Property	$10,213		$10,213
14	TOTAL ELECTRIC OPERATING EXPENSES	$42,463,459	($995,261)	$41,468,198
15	**NET OPERATING INCOME**	$11,095,020	($2,802,675)	$8,292,345
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$1,573,125		$1,573,125
17	LESS: Charitable Donations	$52,724		$52,724
18	Interest Expense on Customer Deposits	$4,080		$4,080
19	Other Interest Expense/(Income)	$21,135		$21,135
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$12,590,205	($2,802,675)	$9,787,531
21	**RATE BASE (from Line 38 below)**	$161,595,895	$0	$161,595,895
22	**ROR EARNED ON AVERAGE RATE BASE**	7.7912%		6.0568%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$5,906,077		$5,906,077
24	Investor Funds Advanced	$2,071,911		$2,071,911
25	Total Additions	$36,851,760		$36,851,760
26	Total Deductions	($30,650,323)		($30,650,323)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$14,179,425	$0	$14,179,425
	NET UTILITY PLANT			
28	Utility Plant in Service	$217,357,669		$217,357,669
29	Acquisition Adjustments	$35,249		$35,249
30	Construction Work in Progress	$40,388,683		$40,388,683
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$79,252,706		$79,252,706
32	Provision for Acquisition Adjustments	$6,019		$6,019
33	TOTAL NET UTILITY PLANT	$178,522,876	$0	$178,522,876
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$412,511		$412,511
35	Accumulated Deferred Income Taxes	$20,470,296		$20,470,296
36	Other Cost Free Capital	$10,223,599		$10,223,599
37	TOTAL RATE BASE DEDUCTIONS	$31,106,406	$0	$31,106,406
38	**TOTAL RATE BASE**	$161,595,895	$0	$161,595,895

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

Schedule NS Class
Annualized Cost of Service Summary

LINE NO.	DESCRIPTION	(1) Sched NS Cost of Service	(2) Annualized Revenue Adjustment	(3) Sched NS Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$19,246,704	$564,600	$19,811,304
2	Forfeited Discounts and Miscellaneous Service Revenues	$79,098	$1,264	$80,362
3	Non-Fuel Rider Revenues	$0	$0	
4	Fuel Revenues	$28,135,491	$0	$28,135,491
5	Other Operating Revenues	$444,714	$0	$444,714
6	TOTAL OPERATING REVENUES	$47,906,007	$565,865	$48,471,872
	OPERATING EXPENSES			
7	Fuel Expense	$28,553,810		$28,553,810
8	Non-Fuel Operating and Maintenance Expense	$9,800,960	$4,121	$9,805,082
9	Depreciation and Amortization	$9,325,245		$9,325,245
10	Federal Income Tax	($1,803,787)	$111,002	($1,692,785)
11	State Income Tax	($404,508)	$32,335	($372,173)
12	Taxes Other than Income Tax	$1,426,215	$829	$1,427,044
13	(Gain)/Loss on Disposition of Property	$11,532		$11,532
14	TOTAL ELECTRIC OPERATING EXPENSES	$46,909,467	$148,287	$47,057,754
15	**NET OPERATING INCOME**	$996,540	$417,578	$1,414,118
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$2,408,710		$2,408,710
17	LESS: Charitable Donations	$63,775		$63,775
18	Interest Expense on Customer Deposits	$3,641		$3,641
19	Other Interest Expense/(Income)	$26,571		$26,571
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$3,311,263	$417,578	$3,728,841
21	**RATE BASE (from Line 38 below)**	$202,505,925	$0	$202,505,925
22	**ROR EARNED ON AVERAGE RATE BASE**	1.6351%		1.8413%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$7,486,650		$7,486,650
24	Investor Funds Advanced	$1,851,256		$1,851,256
25	Total Additions	$47,212,224		$47,212,224
26	Total Deductions	($40,705,739)		($40,705,739)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$15,844,391	$0	$15,844,391
	NET UTILITY PLANT			
28	Utility Plant in Service	$259,043,128		$259,043,128
29	Acquisition Adjustments	$55,224		$55,224
30	Construction Work in Progress	$58,202,066		$58,202,066
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$92,868,521		$92,868,521
32	Provision for Acquisition Adjustments	$9,430		$9,430
33	TOTAL NET UTILITY PLANT	$224,422,467	$0	$224,422,467
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$368,147		$368,147
35	Accumulated Deferred Income Taxes	$25,054,747		$25,054,747
36	Other Cost Free Capital	$12,338,039		$12,338,039
37	TOTAL RATE BASE DEDUCTIONS	$37,760,933	$0	$37,760,933
38	**TOTAL RATE BASE**	$202,505,925	$0	$202,505,925

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

6VP Class
Annualized Cost of Service Summary

LINE NO.	DESCRIPTION	(1) 6VP Cost of Service	(2) Annualized Revenue Adjustment	(3) 6VP Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load			
1	Management	$11,790,961	($1,986,443)	$9,804,518
2	Forfeited Discounts and Miscellaneous Service Revenues	$36,671	$586	$37,257
3	Non-Fuel Rider Revenues	$223	$0	
4	Fuel Revenues	$10,169,761	$0	$10,169,761
5	Other Operating Revenues	$191,500	$0	$191,500
6	TOTAL OPERATING REVENUES	$22,189,117	($1,985,857)	$20,203,259
	OPERATING EXPENSES			
7	Fuel Expense	$10,320,965		$10,320,965
8	Non-Fuel Operating and Maintenance Expense	$4,491,461	($14,463)	$4,476,998
9	Depreciation and Amortization	$4,127,987		$4,127,987
10	Federal Income Tax	($176,193)	($389,552)	($565,745)
11	State Income Tax	$10,050	($113,477)	($103,427)
12	Taxes Other than Income Tax	$664,757	($2,908)	$661,849
13	(Gain)/Loss on Disposition of Property	$7,020		$7,020
14	TOTAL ELECTRIC OPERATING EXPENSES	$19,446,047	($520,400)	$18,925,647
15	**NET OPERATING INCOME**	$2,743,070	($1,465,457)	$1,277,612
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$950,921		$950,921
17	LESS: Charitable Donations	$24,630		$24,630
18	Interest Expense on Customer Deposits	$1,688		$1,688
19	Other Interest Expense/(Income)	$12,019		$12,019
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$3,655,655	($1,465,457)	$2,190,197
21	**RATE BASE (from Line 38 below)**	$91,027,589	$0	$91,027,589
22	**ROR EARNED ON AVERAGE RATE BASE**	4.0160%		2.4061%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$3,050,898		$3,050,898
24	Investor Funds Advanced	$857,984		$857,984
25	Total Additions	$17,502,672		$17,502,672
26	Total Deductions	($15,398,820)		($15,398,820)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$6,012,734	$0	$6,012,734
	NET UTILITY PLANT			
28	Utility Plant in Service	$120,015,180		$120,015,180
29	Acquisition Adjustments	$21,569		$21,569
30	Construction Work in Progress	$23,249,968		$23,249,968
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$41,762,180		$41,762,180
32	Provision for Acquisition Adjustments	$3,683		$3,683
33	TOTAL NET UTILITY PLANT	$101,520,855	$0	$101,520,855
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$170,631		$170,631
35	Accumulated Deferred Income Taxes	$10,600,906		$10,600,906
36	Other Cost Free Capital	$5,734,463		$5,734,463
37	TOTAL RATE BASE DEDUCTIONS	$16,506,000	$0	$16,506,000
38	**TOTAL RATE BASE**	$91,027,589	$0	$91,027,589

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**Street and Outdoor Lighting Class** **Annualized Cost of Service Summary** DESCRIPTION	(1) Street & Outdoor Lighting Cost of Service	(2) Annualized Revenue Adjustment	(3) Street & Outdoor Lighting COS Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$5,178,064	($21,452)	$5,156,611
2	Forfeited Discounts and Miscellaneous Service Revenues	$76,019	$163	$76,182
3	Non-Fuel Rider Revenues	$0	$0	
4	Fuel Revenues	$913,313	$0	$913,313
5	Other Operating Revenues	$69,822	$0	$69,822
6	TOTAL OPERATING REVENUES	$6,237,218	($21,290)	$6,215,928
	OPERATING EXPENSES			
7	Fuel Expense	$926,892		$926,892
8	Non-Fuel Operating and Maintenance Expense	$2,694,951	($155)	$2,694,796
9	Depreciation and Amortization	$2,457,773		$2,457,773
10	Federal Income Tax	($342,295)	($4,176)	($346,471)
11	State Income Tax	($68,210)	($1,217)	($69,426)
12	Taxes Other than Income Tax	$363,021	($31)	$362,990
13	(Gain)/Loss on Disposition of Property	$6,424		$6,424
14	TOTAL ELECTRIC OPERATING EXPENSES	$6,038,556	($5,579)	$6,032,977
15	**NET OPERATING INCOME**	$198,661	($15,711)	$182,951
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$111,447		$111,447
17	LESS: Charitable Donations	$6,022		$6,022
18	Interest Expense on Customer Deposits	$468		$468
19	Other Interest Expense/(Income)	$5,291		$5,291
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$298,327	($15,711)	$282,616
21	**RATE BASE (from Line 38 below)**	$38,511,976	$0	$38,511,976
22	**ROR EARNED ON AVERAGE RATE BASE**	0.7746%		0.7338%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$874,623		$874,623
24	Investor Funds Advanced	$241,599		$241,599
25	Total Additions	$1,994,941		$1,994,941
26	Total Deductions	($2,189,270)		($2,189,270)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$921,893	$0	$921,893
	NET UTILITY PLANT			
28	Utility Plant in Service	$64,380,718		$64,380,718
29	Acquisition Adjustments	$1,824		$1,824
30	Construction Work in Progress	$3,949,813		$3,949,813
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$23,628,682		$23,628,682
32	Provision for Acquisition Adjustments	$312		$312
33	TOTAL NET UTILITY PLANT	$44,703,362	$0	$44,703,362
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$47,328		$47,328
35	Accumulated Deferred Income Taxes	$4,064,621		$4,064,621
36	Other Cost Free Capital	$3,001,329		$3,001,329
37	TOTAL RATE BASE DEDUCTIONS	$7,113,279	$0	$7,113,279
38	**TOTAL RATE BASE**	$38,511,976	$0	$38,511,976

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**Traffic Lighting Class** **Annualized Cost of Service Summary** DESCRIPTION	(1) Traffic Lighting Cost of Service	(2) Annualized Revenue Adjustment	(3) Traffic Lighting Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$51,314	($3,115)	$48,199
2	Forfeited Discounts and Miscellaneous Service Revenues	$899	$2	$901
3	Non-Fuel Rider Revenues	$0	$0	
4	Fuel Revenues	$16,290	$0	$16,290
5	Other Operating Revenues	$613	$0	$613
6	TOTAL OPERATING REVENUES	$69,116	($3,113)	$66,003
	OPERATING EXPENSES			
7	Fuel Expense	$16,532		$16,532
8	Non-Fuel Operating and Maintenance Expense	$25,976	($23)	$25,953
9	Depreciation and Amortization	$12,629		$12,629
10	Federal Income Tax	$683	($611)	$72
11	State Income Tax	$383	($178)	$205
12	Taxes Other than Income Tax	$2,122	($5)	$2,118
13	(Gain)/Loss on Disposition of Property	$28		$28
14	TOTAL ELECTRIC OPERATING EXPENSES	$58,352	($816)	$57,536
15	**NET OPERATING INCOME**	$10,764	($2,297)	$8,467
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$1,150		$1,150
17	LESS: Charitable Donations	$71		$71
18	Interest Expense on Customer Deposits	$5		$5
19	Other Interest Expense/(Income)	$31		$31
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$11,808	($2,297)	$9,511
21	**RATE BASE (from Line 38 below)**	$221,826	$0	$221,826
22	**ROR EARNED ON AVERAGE RATE BASE**	5.3233%		4.2877%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$6,062		$6,062
24	Investor Funds Advanced	$2,676		$2,676
25	Total Additions	$27,957		$27,957
26	Total Deductions	($31,403)		($31,403)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$5,292	$0	$5,292
	NET UTILITY PLANT			
28	Utility Plant in Service	$345,977		$345,977
29	Acquisition Adjustments	$23		$23
30	Construction Work in Progress	$33,730		$33,730
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$121,690		$121,690
32	Provision for Acquisition Adjustments	$4		$4
33	TOTAL NET UTILITY PLANT	$258,035	$0	$258,035
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$525		$525
35	Accumulated Deferred Income Taxes	$25,792		$25,792
36	Other Cost Free Capital	$15,185		$15,185
37	TOTAL RATE BASE DEDUCTIONS	$41,502	$0	$41,502
38	**TOTAL RATE BASE**	$221,826	$0	$221,826

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**Total of All North Carolina Classes** **Annualized Cost of Service Summary** DESCRIPTION	(1) Total Cost of Service	(2) Annualized Revenue Adjustment	(3) Total Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load			
1	Management	$246,761,884	($3,271,458)	$243,490,427
2	Forfeited Discounts and Miscellaneous Service Revenues	$1,253,489	$10,768	$1,264,257
3	Non-Fuel Rider Revenues	$4,604,409	$0	$4,604,409
4	Fuel Revenues	$152,244,208	$0	$152,244,208
5	Other Operating Revenues	$3,332,375	$0	$3,332,375
6	TOTAL OPERATING REVENUES	$408,196,365	($3,260,690)	$404,935,675
	OPERATING EXPENSES			
7	Fuel Expense	$154,507,777	$0	$154,507,777
8	Non-Fuel Operating and Maintenance Expense	$84,631,351	($23,748)	$84,607,603
9	Depreciation and Amortization	$76,966,815	$0	$76,966,815
10	Federal Income Tax	$3,766,678	($639,627)	$3,127,051
11	State Income Tax	$2,295,427	($186,324)	$2,109,103
12	Taxes Other than Income Tax	$12,635,649	($4,774)	$12,630,875
13	(Gain)/Loss on Disposition of Property	$156,151	$0	$156,151
14	TOTAL ELECTRIC OPERATING EXPENSES	$334,959,847	($854,474)	$334,105,374
15	**NET OPERATING INCOME**	$73,236,518	($2,406,216)	$70,830,302
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$14,108,009	$0	$14,108,009
17	LESS: Charitable Donations	$397,631	$0	$397,631
18	Interest Expense on Customer Deposits	$31,017	$0	$31,017
19	Other Interest Expense/(Income)	$212,619	$0	$212,619
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$86,703,259	($2,406,216)	$84,297,043
21	**RATE BASE (from Line 38 below)**	$1,594,851,513	$0	$1,594,851,513
22	**ROR EARNED ON AVERAGE RATE BASE**	5.4364%		5.2856%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$50,733,308	$0	$50,733,308
24	Investor Funds Advanced	$15,791,563	$0	$15,791,563
25	Total Additions	$264,540,117	$0	$264,540,117
26	Total Deductions	($236,039,996)	$0	($236,039,996)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$95,024,991	$0	$95,024,991
	NET UTILITY PLANT			
28	Utility Plant in Service	$2,269,147,992	$0	$2,269,147,992
29	Acquisition Adjustments	$313,057	$0	$313,057
30	Construction Work in Progress	$360,345,332	$0	$360,345,332
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$833,761,769	$0	$833,761,769
32	Provision for Acquisition Adjustments	$53,457	$0	$53,457
33	TOTAL NET UTILITY PLANT	$1,795,991,155	$0	$1,795,991,155
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$3,135,948	$0	$3,135,948
35	Accumulated Deferred Income Taxes	$185,445,996	$0	$185,445,996
36	Other Cost Free Capital	$107,582,689	$0	$107,582,689
37	TOTAL RATE BASE DEDUCTIONS	$296,164,633	$0	$296,164,633
38	**TOTAL RATE BASE**	$1,594,851,513	$0	$1,594,851,513

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

Residential Class
Fully Adjusted Cost of Service and Revenue Requirement
Adjusted Net Operating Income and Rate of Return

LINE NO.	DESCRIPTION	(1) Residential Cost of Service	(2) Ratemaking Adjustments	(3) Residential Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) Residential Base Non-Fuel Additional Revenue Requirement	(5) Residential Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$129,458,161	$11,064,479	$140,522,639	$30,041,872	$170,564,512
2	Forfeited Discounts and Misc. Service Revenues	$761,746	$27,665	$789,410	($164,523)	$624,888
3	Non-Fuel Rider Revenues	$2,842,691	($2,842,691)	$0		$0
4	Fuel Revenues	$60,621,360	($6,088,841)	$54,532,519		$54,532,519
5	Other Operating Revenues	$1,591,849	($5,427)	$1,586,422		$1,586,422
6	TOTAL OPERATING REVENUES	$195,275,807	$2,155,184	$197,430,991	$29,877,350	$227,308,341
	OPERATING EXPENSES					
7	Fuel Expense	$61,522,679	($7,070,595)	$54,452,084		$54,452,084
8	Non-Fuel Operating and Maintenance Expense	$40,530,614	$8,532,087	$49,062,701	$261,350	$49,324,052
9	Depreciation and Amortization	$37,956,286	$301,600	$38,257,886		$38,257,886
10	Federal Income Tax	$3,873,519	$875,442	$4,748,961	$5,860,834	$10,609,794
11	State Income Tax	$1,745,535	$254,640	$2,000,175	$1,707,268	$3,707,443
12	Taxes Other than Income Tax	$6,410,309	$254,491	$6,664,800		$6,664,800
13	(Gain)/Loss on Disposition of Property	$88,493	($123,968)	($35,475)		($35,475)
14	TOTAL ELECTRIC OPERATING EXPENSES	$152,127,435	$3,023,697	$155,151,132	$7,829,452	$162,980,584
15	**NET OPERATING INCOME**	$43,148,372	($868,513)	$42,279,859	$22,047,898	$64,327,757
	ADJUSTMENTS TO OPERATING INCOME					
16	*ADD:* AFUDC	$6,172,568	($6,172,568)	$0		$0
17	*LESS:* Charitable Donations	$169,690	($169,690)	$0		$0
18	Interest Expense on Customer Deposits	$14,826		$14,826		$14,826
19	Other Interest Expense/(Income)	$104,196		$104,196		$104,196
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$49,032,227	($6,871,391)	$42,160,836	$22,047,898	$64,208,734
21	**RATE BASE (from Line 38 below)**	$775,661,985	($115,705,012)	$659,956,973	$10,330,981	$670,287,954
22	**ROR EARNED ON AVERAGE RATE BASE**	6.3213%		6.3884%		9.5793%

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Residential Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Rate Base** DESCRIPTION	**(1)** **Residential Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **Residential Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **Residential Base Non-Fuel Additional Revenue Requirement**	**(5)** **Residential Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$23,213,982	$0	$23,213,982		$23,213,982
24	Investor Funds Advanced	$7,556,586	$11,746,554	$19,303,140	$10,330,981	$29,634,121
25	Total Additions	$108,752,402	($85,629,673)	$23,122,729		$23,122,729
26	Total Deductions	($100,218,584)	$82,752,720	($17,465,864)		($17,465,864)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$39,304,386	$8,869,601	$48,173,987	$10,330,981	$58,504,968
	NET UTILITY PLANT					
28	Utility Plant in Service	$1,147,036,872	$45,181,211	$1,192,218,082		$1,192,218,082
29	Acquisition Adjustments	$134,953	($134,953)	$0		$0
30	Construction Work in Progress	$161,220,411	($161,220,411)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$428,201,921	$19,979,354	$448,181,276		$448,181,276
32	Provision for Acquisition Adjustments	$23,044	($23,044)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$880,167,270	($136,130,463)	$744,036,807	$0	$744,036,807
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$1,498,955		$1,498,955		$1,498,955
35	Accumulated Deferred Income Taxes	$87,971,837	($10,669,757)	$77,302,081		$77,302,081
36	Other Cost Free Capital	$54,338,878	($886,093)	$53,452,786		$53,452,786
37	TOTAL RATE BASE DEDUCTIONS	$143,809,671	($11,555,849)	$132,253,821	$0	$132,253,821
38	**TOTAL RATE BASE**	$775,661,985	($115,705,012)	$659,956,973	$10,330,981	$670,287,954

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

Small General Service, County, & Muni Class
Fully Adjusted Cost of Service and Revenue Requirement
Adjusted Net Operating Income and Rate of Return

LINE NO.	DESCRIPTION	(1) SGS Cost of Service	(2) Ratemaking Adjustments	(3) SGS Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) SGS Base Non-Fuel Additional Revenue Requirement	(5) SGS Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$51,071,052	$8,548	$51,079,600	$12,811,563	$63,891,163
2	Forfeited Discounts and Misc. Service Revenues	$210,233	$9,925	$220,158	($24,952)	$195,206
3	Non-Fuel Rider Revenues	$1,325,418	($1,325,418)	$0		$0
4	Fuel Revenues	$29,697,669	($2,982,849)	$26,714,819		$26,714,819
5	Other Operating Revenues	$656,251	($3,137)	$653,115		$653,115
6	TOTAL OPERATING REVENUES	$82,960,622	($4,292,930)	$78,667,692	$12,786,611	$91,454,303
	OPERATING EXPENSES					
7	Fuel Expense	$30,139,214	($3,463,799)	$26,675,415		$26,675,415
8	Non-Fuel Operating and Maintenance Expense	$18,406,564	$2,172,061	$20,578,625	$111,850	$20,690,475
9	Depreciation and Amortization	$15,479,490	($12,044)	$15,467,447		$15,467,447
10	Federal Income Tax	$800,575	($258,324)	$542,251	$2,508,261	$3,050,512
11	State Income Tax	$476,658	($75,429)	$401,229	$730,659	$1,131,888
12	Taxes Other than Income Tax	$2,581,589	$103,901	$2,685,490		$2,685,490
13	(Gain)/Loss on Disposition of Property	$32,441	($49,820)	($17,379)		($17,379)
14	TOTAL ELECTRIC OPERATING EXPENSES	$67,916,531	($1,583,454)	$66,333,078	$3,350,771	$69,683,849
15	**NET OPERATING INCOME**	$15,044,091	($2,709,477)	$12,334,614	$9,435,840	$21,770,455
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$2,890,087	($2,890,087)	$0		$0
17	LESS: Charitable Donations	$80,720	($80,720)	$0		$0
18	Interest Expense on Customer Deposits	$6,309		$6,309		$6,309
19	Other Interest Expense/(Income)	$43,376		$43,376		$43,376
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$17,803,773	($5,518,843)	$12,284,929	$9,435,840	$21,720,770
21	**RATE BASE (from Line 38 below)**	$325,326,317	($53,790,783)	$271,535,534	$4,696,148	$276,231,682
22	**ROR EARNED ON AVERAGE RATE BASE**	5.4726%		4.5242%		7.8632%

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

Small General Service, County, & Muni Class
Fully Adjusted Cost of Service and Revenue Requirement
Rate Base

LINE NO.	DESCRIPTION	(1) SGS Cost of Service	(2) Ratemaking Adjustments	(3) SGS Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) SGS Base Non-Fuel Additional Revenue Requirement	(5) SGS Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$10,195,017	$0	$10,195,017		$10,195,017
24	Investor Funds Advanced	$3,209,551	$4,990,385	$8,199,936	$4,696,148	$12,896,084
25	Total Additions	$52,198,160	($41,726,481)	$10,471,679		$10,471,679
26	Total Deductions	($46,845,857)	$39,877,647	($6,968,210)		($6,968,210)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$18,756,870	$3,141,550	$21,898,421	$4,696,148	$26,594,569
	NET UTILITY PLANT					
28	Utility Plant in Service	$460,968,449	$18,302,183	$479,270,632		$479,270,632
29	Acquisition Adjustments	$64,215	($64,215)	$0		$0
30	Construction Work in Progress	$73,300,660	($73,300,660)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$167,926,069	$7,841,122	$175,767,191		$175,767,191
32	Provision for Acquisition Adjustments	$10,965	($10,965)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$366,396,290	($62,892,849)	$303,503,441	$0	$303,503,441
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$637,850		$637,850		$637,850
35	Accumulated Deferred Income Taxes	$37,257,798	($5,604,154)	$31,653,644		$31,653,644
36	Other Cost Free Capital	$21,931,195	($356,361)	$21,574,833		$21,574,833
37	TOTAL RATE BASE DEDUCTIONS	$59,826,843	($5,960,516)	$53,866,327	$0	$53,866,327
38	**TOTAL RATE BASE**	$325,326,317	($53,790,783)	$271,535,534	$4,696,148	$276,231,682

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Large General Service Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **LGS Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **LGS Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **LGS Base Non-Fuel Additional Revenue Requirement**	**(5)** **LGS Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$29,965,629	($4,340,877)	$25,624,752	$5,469,947	$31,094,698
2	Forfeited Discounts and Misc. Service Revenues	$88,823	$5,654	$94,477	($14,337)	$80,140
3	Non-Fuel Rider Revenues	$436,077	($436,077)	$0		$0
4	Fuel Revenues	$22,690,325	($2,279,028)	$20,411,297		$20,411,297
5	Other Operating Revenues	$377,625	($5,877)	$371,748		$371,748
6	TOTAL OPERATING REVENUES	$53,558,478	($7,056,204)	$46,502,274	$5,455,610	$51,957,883
	OPERATING EXPENSES					
7	Fuel Expense	$23,027,685	($2,646,495)	$20,381,190		$20,381,190
8	Non-Fuel Operating and Maintenance Expense	$8,680,825	$1,933,819	$10,614,645	$47,723	$10,662,367
9	Depreciation and Amortization	$7,607,405	($111,355)	$7,496,051		$7,496,051
10	Federal Income Tax	$1,414,175	($1,063,803)	$350,372	$1,070,189	$1,420,561
11	State Income Tax	$535,519	($309,986)	$225,533	$311,747	$537,281
12	Taxes Other than Income Tax	$1,187,636	$49,031	$1,236,667		$1,236,667
13	(Gain)/Loss on Disposition of Property	$10,213	($23,491)	($13,278)		($13,278)
14	TOTAL ELECTRIC OPERATING EXPENSES	$42,463,459	($2,172,278)	$40,291,180	$1,429,659	$41,720,840
15	**NET OPERATING INCOME**	$11,095,020	($4,883,926)	$6,211,094	$4,025,950	$10,237,044
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$1,573,125	($1,573,125)	$0		$0
17	LESS: Charitable Donations	$52,724	($52,724)	$0		$0
18	Interest Expense on Customer Deposits	$4,080		$4,080		$4,080
19	Other Interest Expense/(Income)	$21,135		$21,135		$21,135
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$12,590,205	($6,404,327)	$6,185,878	$4,025,950	$10,211,829
21	**RATE BASE (from Line 38 below)**	$161,595,895	($29,834,241)	$131,761,654	$3,056,935	$134,818,588
22	**ROR EARNED ON AVERAGE RATE BASE**	7.7912%		4.6947%		7.5745%

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

Large General Service Class
Fully Adjusted Cost of Service and Revenue Requirement
Rate Base

LINE NO.	DESCRIPTION	(1) LGS Cost of Service	(2) Ratemaking Adjustments	(3) LGS Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) LGS Base Non-Fuel Additional Revenue Requirement	(5) LGS Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$5,906,077	$0	$5,906,077		$5,906,077
24	Investor Funds Advanced	$2,071,911	$3,221,738	$5,293,649	$3,056,935	$8,350,583
25	Total Additions	$36,851,760	($30,476,595)	$6,375,165		$6,375,165
26	Total Deductions	($30,650,323)	$27,330,101	($3,320,222)		($3,320,222)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$14,179,425	$75,244	$14,254,670	$3,056,935	$17,311,604
	NET UTILITY PLANT					
28	Utility Plant in Service	$217,357,669	$8,702,070	$226,059,739		$226,059,739
29	Acquisition Adjustments	$35,249	($35,249)	$0		$0
30	Construction Work in Progress	$40,388,683	($40,388,683)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$79,252,706	$3,685,496	$82,938,202		$82,938,202
32	Provision for Acquisition Adjustments	$6,019	($6,019)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$178,522,876	($35,401,339)	$143,121,537	$0	$143,121,537
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$412,511		$412,511		$412,511
35	Accumulated Deferred Income Taxes	$20,470,296	($5,326,563)	$15,143,733		$15,143,733
36	Other Cost Free Capital	$10,223,599	($165,291)	$10,058,308		$10,058,308
37	TOTAL RATE BASE DEDUCTIONS	$31,106,406	($5,491,854)	$25,614,552	$0	$25,614,552
38	**TOTAL RATE BASE**	$161,595,895	($29,834,241)	$131,761,654	$3,056,935	$134,818,588

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Schedule NS Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **Schedule NS Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **Schedule NS Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **Schedule NS Base Non-Fuel Additional Revenue Requirement**	**(5)** **Schedule NS Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
	Base Non-Fuel Rate Revenues, Including Facilities Charges &					
1	Load Management	$19,246,704	$2,781,987	$22,028,691	$4,460,054	$26,488,745
2	Forfeited Discounts and Misc. Service Revenues	$79,098	$5,043	$84,142	($14,866)	$69,275
3	Non-Fuel Rider Revenues	$0	$0	$0		$0
4	Fuel Revenues	$28,135,491	($2,825,943)	$25,309,548		$25,309,548
5	Other Operating Revenues	$444,714	($4,386)	$440,328		$440,328
6	TOTAL OPERATING REVENUES	$47,906,007	($43,299)	$47,862,708	$4,445,187	$52,307,896
	OPERATING EXPENSES					
7	Fuel Expense	$28,553,810	($3,281,594)	$25,272,216		$25,272,216
8	Non-Fuel Operating and Maintenance Expense	$9,800,960	$3,272,176	$13,073,136	$38,884	$13,112,020
9	Depreciation and Amortization	$9,325,245	($268,357)	$9,056,888		$9,056,888
10	Federal Income Tax	($1,803,787)	$249,145	($1,554,642)	$871,982	($682,660)
11	State Income Tax	($404,508)	$72,422	($332,086)	$254,009	($78,077)
12	Taxes Other than Income Tax	$1,426,215	$61,018	$1,487,233		$1,487,233
13	(Gain)/Loss on Disposition of Property	$11,532	($27,997)	($16,464)		($16,464)
14	TOTAL ELECTRIC OPERATING EXPENSES	$46,909,467	$76,813	$46,986,280	$1,164,875	$48,151,155
15	**NET OPERATING INCOME**	$996,540	($120,112)	$876,429	$3,280,312	$4,156,741
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$2,408,710	($2,408,710)	$0		$0
17	LESS: Charitable Donations	$63,775	($63,775)	$0		$0
18	Interest Expense on Customer Deposits	$3,641		$3,641		$3,641
19	Other Interest Expense/(Income)	$26,571		$26,571		$26,571
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$3,311,263	($2,465,046)	$846,217	$3,280,312	$4,126,529
21	**RATE BASE (from Line 38 below)**	$202,505,925	($45,559,978)	$156,945,947	$3,428,920	$160,374,867
22	**ROR EARNED ON AVERAGE RATE BASE**	1.6351%		0.5392%		2.5731%

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

Schedule NS Class
Fully Adjusted Cost of Service and Revenue Requirement
Rate Base

LINE NO.	DESCRIPTION	(1) Schedule NS Cost of Service	(2) Ratemaking Adjustments	(3) Schedule NS Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) Schedule NS Base Non-Fuel Additional Revenue Requirement	(5) Schedule NS Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$7,486,650	$0	$7,486,650		$7,486,650
24	Investor Funds Advanced	$1,851,256	$2,881,722	$4,732,978	$3,428,920	$8,161,898
25	Total Additions	$47,212,224	($38,916,823)	$8,295,401		$8,295,401
26	Total Deductions	($40,705,739)	$36,179,970	($4,525,769)		($4,525,769)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$15,844,391	$144,869	$15,989,260	$3,428,920	$19,418,180
	NET UTILITY PLANT					
28	Utility Plant in Service	$259,043,128	$10,562,787	$269,605,915		$269,605,915
29	Acquisition Adjustments	$55,224	($55,224)	$0		$0
30	Construction Work in Progress	$58,202,066	($58,202,066)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$92,868,521	$4,326,239	$97,194,760		$97,194,760
32	Provision for Acquisition Adjustments	$9,430	($9,430)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$224,422,467	($52,011,312)	$172,411,155	$0	$172,411,155
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$368,147		$368,147		$368,147
35	Accumulated Deferred Income Taxes	$25,054,747	($6,108,632)	$18,946,115		$18,946,115
36	Other Cost Free Capital	$12,338,039	($197,833)	$12,140,206		$12,140,206
37	TOTAL RATE BASE DEDUCTIONS	$37,760,933	($6,306,465)	$31,454,468	$0	$31,454,468
38	**TOTAL RATE BASE**	$202,505,925	($45,559,978)	$156,945,947	$3,428,920	$160,374,867

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**6VP Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **6VP Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **6VP Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **6VP Base Non-Fuel Additional Revenue Requirement**	**(5)** **6VP Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
	Base Non-Fuel Rate Revenues, Including Facilities Charges &					
1	Load Management	$11,790,961	($1,745,467)	$10,045,495	$2,020,862	$12,066,357
2	Forfeited Discounts and Misc. Service Revenues	$36,671	$2,338	$39,009	($8,098)	$30,911
3	Non-Fuel Rider Revenues	$223	($223)	$0		$0
4	Fuel Revenues	$10,169,761	($1,021,456)	$9,148,305		$9,148,305
5	Other Operating Revenues	$191,500	($1,180)	$190,320		$190,320
6	TOTAL OPERATING REVENUES	$22,189,117	($2,765,989)	$19,423,128	$2,012,764	$21,435,892
	OPERATING EXPENSES					
7	Fuel Expense	$10,320,965	($1,186,154)	$9,134,811		$9,134,811
8	Non-Fuel Operating and Maintenance Expense	$4,491,461	$1,284,581	$5,776,042	$17,607	$5,793,649
9	Depreciation and Amortization	$4,127,987	($69,237)	$4,058,749		$4,058,749
10	Federal Income Tax	($176,193)	($461,109)	($637,302)	$394,830	($242,472)
11	State Income Tax	$10,050	($134,382)	($124,332)	$115,014	($9,317)
12	Taxes Other than Income Tax	$664,757	$27,491	$692,248		$692,248
13	(Gain)/Loss on Disposition of Property	$7,020	($12,971)	($5,951)		($5,951)
14	TOTAL ELECTRIC OPERATING EXPENSES	$19,446,047	($551,781)	$18,894,266	$527,451	$19,421,717
15	**NET OPERATING INCOME**	$2,743,070	($2,214,207)	$528,863	$1,485,313	$2,014,175
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$950,921	($950,921)	$0		$0
17	LESS: Charitable Donations	$24,630	($24,630)	$0		$0
18	Interest Expense on Customer Deposits	$1,688		$1,688		$1,688
19	Other Interest Expense/(Income)	$12,019		$12,019		$12,019
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$3,655,655	($3,140,499)	$515,156	$1,485,313	$2,000,469
21	**RATE BASE (from Line 38 below)**	$91,027,589	($17,659,388)	$73,368,201	$1,410,919	$74,779,120
22	**ROR EARNED ON AVERAGE RATE BASE**	4.0160%		0.7022%		2.6752%

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

6VP Class
Fully Adjusted Cost of Service and Revenue Requirement
Rate Base

LINE NO.	DESCRIPTION	(1) 6VP Cost of Service	(2) Ratemaking Adjustments	(3) 6VP Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) 6VP Base Non-Fuel Additional Revenue Requirement	(5) 6VP Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$3,050,898	$0	$3,050,898		$3,050,898
24	Investor Funds Advanced	$857,984	$1,334,757	$2,192,741	$1,410,919	$3,603,659
25	Total Additions	$17,502,672	($14,234,025)	$3,268,647		$3,268,647
26	Total Deductions	($15,398,820)	$13,465,734	($1,933,086)		($1,933,086)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$6,012,734	$566,465	$6,579,199	$1,410,919	$7,990,118
	NET UTILITY PLANT					
28	Utility Plant in Service	$120,015,180	$4,835,457	$124,850,638		$124,850,638
29	Acquisition Adjustments	$21,569	($21,569)	$0		$0
30	Construction Work in Progress	$23,249,968	($23,249,968)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$41,762,180	$1,952,520	$43,714,700		$43,714,700
32	Provision for Acquisition Adjustments	$3,683	($3,683)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$101,520,855	($20,384,917)	$81,135,938	$0	$81,135,938
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$170,631		$170,631		$170,631
35	Accumulated Deferred Income Taxes	$10,600,906	($2,066,544)	$8,534,363		$8,534,363
36	Other Cost Free Capital	$5,734,463	($92,521)	$5,641,942		$5,641,942
37	TOTAL RATE BASE DEDUCTIONS	$16,506,000	($2,159,064)	$14,346,936	$0	$14,346,936
38	**TOTAL RATE BASE**	$91,027,589	($17,659,388)	$73,368,201	$1,410,919	$74,779,120

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Street and Outdoor Lighting Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **St. & Out. Lighting Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **St. & Out. Lighting Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **St. & Out. Lighting Base Non-Fuel Additional Revenue Requirement**	**(5)** **St. & Out. Lighting Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$5,178,064	$72,534	$5,250,597	$2,067,256	$7,317,853
2	Forfeited Discounts and Misc. Service Revenues	$76,019	$1,716	$77,735	($31,835)	$45,901
3	Non-Fuel Rider Revenues	$0	$0	$0		$0
4	Fuel Revenues	$913,313	($91,734)	$821,579		$821,579
5	Other Operating Revenues	$69,822	($134)	$69,688		$69,688
6	TOTAL OPERATING REVENUES	$6,237,218	($17,618)	$6,219,600	$2,035,421	$8,255,021
	OPERATING EXPENSES					
7	Fuel Expense	$926,892	($106,525)	$820,368		$820,368
8	Non-Fuel Operating and Maintenance Expense	$2,694,951	$234,983	$2,929,934	$17,805	$2,947,739
9	Depreciation and Amortization	$2,457,773	$120,164	$2,577,936		$2,577,936
10	Federal Income Tax	($342,295)	($14,189)	($356,484)	$399,275	$42,791
11	State Income Tax	($68,210)	($4,138)	($72,348)	$116,309	$43,961
12	Taxes Other than Income Tax	$363,021	$13,603	$376,624		$376,624
13	(Gain)/Loss on Disposition of Property	$6,424	($6,958)	($534)		($534)
14	TOTAL ELECTRIC OPERATING EXPENSES	$6,038,556	$236,939	$6,275,495	$533,388	$6,808,884
15	**NET OPERATING INCOME**	$198,661	($254,557)	($55,896)	$1,502,033	$1,446,137
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$111,447	($111,447)	$0		$0
17	LESS: Charitable Donations	$6,022	($6,022)	$0		$0
18	Interest Expense on Customer Deposits	$468		$468		$468
19	Other Interest Expense/(Income)	$5,291		$5,291		$5,291
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$298,327	($359,982)	($61,655)	$1,502,033	$1,440,377
21	**RATE BASE (from Line 38 below)**	$38,511,976	($2,158,341)	$36,353,636	$274,905	$36,628,541
22	**ROR EARNED ON AVERAGE RATE BASE**	0.7746%		-0.1696%		3.9324%

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

Street and Outdoor Lighting Class
Fully Adjusted Cost of Service and Revenue Requirement
Rate Base

LINE NO.	DESCRIPTION	(1) St. & Out. Lighting Cost of Service	(2) Ratemaking Adjustments	(3) St. & Out. Lighting Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) St. & Out. Lighting Base Non-Fuel Additional Revenue Requirement	(5) St. & Out. Lighting Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$874,623	$0	$874,623		$874,623
24	Investor Funds Advanced	$241,599	$375,191	$616,791	$274,905	$891,696
25	Total Additions	$1,994,941	($1,286,505)	$708,436		$708,436
26	Total Deductions	($2,189,270)	$1,271,321	($917,949)		($917,949)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$921,893	$360,007	$1,281,900	$274,905	$1,556,805
	NET UTILITY PLANT					
28	Utility Plant in Service	$64,380,718	$2,452,458	$66,833,176		$66,833,176
29	Acquisition Adjustments	$1,824	($1,824)	$0		$0
30	Construction Work in Progress	$3,949,813	($3,949,813)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$23,628,682	$1,136,410	$24,765,092		$24,765,092
32	Provision for Acquisition Adjustments	$312	($312)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$44,703,362	($2,635,278)	$42,068,084	$0	$42,068,084
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$47,328		$47,328		$47,328
35	Accumulated Deferred Income Taxes	$4,064,621	($67,241)	$3,997,380		$3,997,380
36	Other Cost Free Capital	$3,001,329	($49,690)	$2,951,640		$2,951,640
37	TOTAL RATE BASE DEDUCTIONS	$7,113,279	($116,930)	$6,996,348	$0	$6,996,348
38	**TOTAL RATE BASE**	$38,511,976	($2,158,341)	$36,353,636	$274,905	$36,628,541

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Traffic Lighting Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **Traffic Lighting Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **Traffic Lighting Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **Traffic Lighting Base Non-Fuel Additional Revenue Requirement**	**(5)** **Traffic Lighting Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$51,314	($357)	$50,957	$11,467	$62,424
2	Forfeited Discounts and Misc. Service Revenues	$899	$20	$919	($436)	$483
3	Non-Fuel Rider Revenues	$0	$0	$0		$0
4	Fuel Revenues	$16,290	($1,636)	$14,654		$14,654
5	Other Operating Revenues	$613	($5)	$609		$609
6	TOTAL OPERATING REVENUES	$69,116	($1,978)	$67,138	$11,031	$78,169
	OPERATING EXPENSES					
7	Fuel Expense	$16,532	($1,900)	$14,632		$14,632
8	Non-Fuel Operating and Maintenance Expense	$25,976	$2,969	$28,945	$96	$29,041
9	Depreciation and Amortization	$12,629	$295	$12,924		$12,924
10	Federal Income Tax	$683	($426)	$257	$2,164	$2,421
11	State Income Tax	$383	($124)	$258	$630	$889
12	Taxes Other than Income Tax	$2,122	$95	$2,218		$2,218
13	(Gain)/Loss on Disposition of Property	$28	($37)	($10)		($10)
14	TOTAL ELECTRIC OPERATING EXPENSES	$58,352	$873	$59,224	$2,891	$62,115
15	**NET OPERATING INCOME**	$10,764	($2,851)	$7,914	$8,140	$16,054
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$1,150	($1,150)	$0		$0
17	LESS: Charitable Donations	$71	($71)	$0		$0
18	Interest Expense on Customer Deposits	$5		$5		$5
19	Other Interest Expense/(Income)	$31		$31		$31
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$11,808	($3,930)	$7,878	$8,140	$16,018
21	**RATE BASE (from Line 38 below)**	$221,826	($18,279)	$203,546	$2,052	$205,598
22	**ROR EARNED ON AVERAGE RATE BASE**	5.3233%		3.8703%		7.7911%

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

Traffic Lighting Class
Fully Adjusted Cost of Service and Revenue Requirement
Rate Base

LINE NO.	DESCRIPTION	(1) Traffic Lighting Cost of Service	(2) Ratemaking Adjustments	(3) Traffic Lighting Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) Traffic Lighting Base Non-Fuel Additional Revenue Requirement	(5) Traffic Lighting Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$6,062	$0	$6,062		$6,062
24	Investor Funds Advanced	$2,676	$4,158	$6,834	$2,052	$8,886
25	Total Additions	$27,957	($21,769)	$6,188		$6,188
26	Total Deductions	($31,403)	$21,888	($9,515)		($9,515)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$5,292	$4,276	$9,568	$2,052	$11,620
	NET UTILITY PLANT					
28	Utility Plant in Service	$345,977	$13,378	$359,355		$359,355
29	Acquisition Adjustments	$23	($23)	$0		$0
30	Construction Work in Progress	$33,730	($33,730)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$121,690	$5,797	$127,487		$127,487
32	Provision for Acquisition Adjustments	$4	($4)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$258,035	($26,168)	$231,867	$0	$231,867
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$525		$525		$525
35	Accumulated Deferred Income Taxes	$25,792	($3,363)	$22,428		$22,428
36	Other Cost Free Capital	$15,185	($249)	$14,935		$14,935
37	TOTAL RATE BASE DEDUCTIONS	$41,502	($3,613)	$37,889	$0	$37,889
38	**TOTAL RATE BASE**	$221,826	($18,279)	$203,546	$2,052	$205,598

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Total of All North Carolina Classes** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **Total NC Jurisdiction Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **Total NC Jurisdiction Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **Total NC Jurisdiction Base Non-Fuel Additional Revenue Requirement**	**(5)** **Total NC Jurisdiction Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
	Base Non-Fuel Rate Revenues, Including Facilities Charges &					
1	Load Management	$246,761,884	$7,840,847	$254,602,731	$56,883,021	$311,485,752
2	Forfeited Discounts and Misc. Service Revenues	$1,253,489	$52,361	$1,305,850	($259,047)	$1,046,803
3	Non-Fuel Rider Revenues	$4,604,409	($4,604,409)	$0	$0	$0
4	Fuel Revenues	$152,244,208	($15,291,487)	$136,952,721	$0	$136,952,721
5	Other Operating Revenues	$3,332,375	($20,146)	$3,312,229	$0	$3,312,229
6	TOTAL OPERATING REVENUES	$408,196,365	($12,022,834)	$396,173,531	$56,623,974	$452,797,505
	OPERATING EXPENSES					
7	Fuel Expense	$154,507,777	($17,757,061)	$136,750,716	$0	$136,750,716
8	Non-Fuel Operating and Maintenance Expense	$84,631,351	$17,432,677	$102,064,028	$495,315	$102,559,343
9	Depreciation and Amortization	$76,966,815	($38,935)	$76,927,880	$0	$76,927,880
10	Federal Income Tax	$3,766,678	($673,265)	$3,093,413	$11,107,535	$14,200,947
11	State Income Tax	$2,295,427	($196,997)	$2,098,430	$3,235,638	$5,334,068
12	Taxes Other than Income Tax	$12,635,649	$509,630	$13,145,279	$0	$13,145,279
13	(Gain)/Loss on Disposition of Property	$156,151	($245,242)	($89,091)	$0	($89,091)
14	TOTAL ELECTRIC OPERATING EXPENSES	$334,959,847	($969,192)	$333,990,655	$14,838,487	$348,829,142
15	**NET OPERATING INCOME**	$73,236,518	($11,053,642)	$62,182,876	$41,785,487	$103,968,363
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$14,108,009	($14,108,009)	$0	$0	$0
17	LESS: Charitable Donations	$397,631	($397,631)	$0	$0	$0
18	Interest Expense on Customer Deposits	$31,017	$0	$31,017	$0	$31,017
19	Other Interest Expense/(Income)	$212,619	$0	$212,619	$0	$212,619
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$86,703,259	($24,764,019)	$61,939,239	$41,785,487	$103,724,727
21	**RATE BASE (from Line 38 below)**	$1,594,851,513	($264,726,022)	$1,330,125,491	$23,200,860	$1,353,326,351
22	**ROR EARNED ON AVERAGE RATE BASE**	5.4364%		4.6566%		7.6644%

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

Total of All North Carolina Classes
Fully Adjusted Cost of Service and Revenue Requirement
Rate Base

LINE NO.	DESCRIPTION	(1) Total NC Jurisdiction Cost of Service	(2) Ratemaking Adjustments	(3) Total NC Jurisdiction Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) Total NC Jurisdiction Base Non-Fuel Additional Revenue Requirement	(5) Total NC Jurisdiction Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$50,733,308	$0	$50,733,308	$0	$50,733,308
24	Investor Funds Advanced	$15,791,563	$24,554,504	$40,346,067	$23,200,860	$63,546,927
25	Total Additions	$264,540,117	($212,291,872)	$52,248,245	$0	$52,248,245
26	Total Deductions	($236,039,996)	$200,899,380	($35,140,616)	$0	($35,140,616)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$95,024,991	$13,162,012	$108,187,004	$23,200,860	$131,387,864
	NET UTILITY PLANT					
28	Utility Plant in Service	$2,269,147,992	$90,049,544	$2,359,197,536	$0	$2,359,197,536
29	Acquisition Adjustments	$313,057	($313,057)	$0	$0	$0
30	Construction Work in Progress	$360,345,332	($360,345,332)	$0	$0	$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$833,761,769	$38,926,938	$872,688,708	$0	$872,688,708
32	Provision for Acquisition Adjustments	$53,457	($53,457)	($0)	$0	($0)
33	TOTAL NET UTILITY PLANT	$1,795,991,155	($309,482,326)	$1,486,508,829	$0	$1,486,508,829
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$3,135,948	$0	$3,135,948	$0	$3,135,948
35	Accumulated Deferred Income Taxes	$185,445,996	($29,846,253)	$155,599,743	$0	$155,599,743
36	Other Cost Free Capital	$107,582,689	($1,748,038)	$105,834,651	$0	$105,834,651
37	TOTAL RATE BASE DEDUCTIONS	$296,164,633	($31,594,291)	$264,570,342	$0	$264,570,342
38	**TOTAL RATE BASE**	$1,594,851,513	($264,726,022)	$1,330,125,491	$23,200,860	$1,353,326,351

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
SUMMARY OF NORTH CAROLINA JURISDICTION AND CUSTOMER CLASS RATES OF RETURN
PER BOOKS, ANNUALIZED, FULLY ADJUSTED AND FULLY ADJUSTED WITH INCREASE

PER BOOKS CLASS RATE OF RETURNS - FROM ITEM 45a

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$86,703,259	$49,032,227	$17,803,773	$12,590,205	$3,311,263	$3,655,655	$298,327	$11,808
Rate Base	$1,594,851,513	$775,661,985	$325,326,317	$161,595,895	$202,505,925	$91,027,589	$38,511,976	$221,826
ROR	5.4364%	6.3213%	5.4726%	7.7912%	1.6351%	4.0160%	0.7746%	5.3233%
Index		1.16	1.01	1.43	0.30	0.74	0.14	0.98

PER BOOKS CLASS RATE OF RETURNS WITH ANNUALIZED REVENUE - FROM ITEM 45b

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$84,297,043	$51,222,986	$17,075,360	$9,787,531	$3,728,841	$2,190,197	$282,616	$9,511
Rate Base	$1,594,851,513	$775,661,985	$325,326,317	$161,595,895	$202,505,925	$91,027,589	$38,511,976	$221,826
ROR	5.2856%	6.6038%	5.2487%	6.0568%	1.8413%	2.4061%	0.7338%	4.2877%
Index		1.25	0.99	1.15	0.35	0.46	0.14	0.81

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS BEFORE REVENUE INCREASE - FROM ITEM 45c, COL. 3

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$61,939,239	$42,160,836	$12,284,929	$6,185,878	$846,217	$515,156	($61,655)	$7,878
Rate Base	$1,330,125,491	$659,956,973	$271,535,534	$131,761,654	$156,945,947	$73,368,201	$36,353,636	$203,546
ROR	4.6566%	6.3884%	4.5242%	4.6947%	0.5392%	0.7022%	-0.1696%	3.8703%
Index		1.37	0.97	1.01	0.12	0.15	-0.04	0.83

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS AND AFTER REVENUE INCREASE - FROM ITEM 45c, COLS. 4 & 5

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Revenue Increase	$56,623,974	$29,877,350	$12,786,611	$5,455,610	$4,445,187	$2,012,764	$2,035,421	$11,031
Adjusted NOI	$103,724,727	$64,208,734	$21,720,770	$10,211,829	$4,126,529	$2,000,469	$1,440,377	$16,018
Rate Base	$1,353,326,351	$670,287,954	$276,231,682	$134,818,588	$160,374,867	$74,779,120	$36,628,541	$205,598
ROR	7.6644%	9.5793%	7.8632%	7.5745%	2.5731%	2.6752%	3.9324%	7.7911%
Index		1.25	1.03	0.99	0.34	0.35	0.51	1.02

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

				Demand					
	Energy 66.1203%			Production			Transmission	Distribution	
	Demand 33.8797%	Total	Customer	Demand	Energy	Combined			Energy
1	NOI (COS Sch 1, Ln 36)	$49,032,227	$7,508,830	$6,571,567	$12,825,195	$19,396,762	$9,470,079	$10,402,743	$2,253,814
2	NOI Ratio (Based on Ln 1)	100.0000%	15.3141%	13.4025%	26.1567%	39.5592%	19.3140%	21.2161%	4.5966%
3	Rate Base (COS Sch 1, Ln 38)	$775,661,985	$118,785,420	$103,958,464	$202,887,298	$306,845,762	$149,811,265	$164,565,479	$35,654,058
4	Rate Base Ratio (Based on Ln 3)	100.0000%	15.3141%	13.4025%	26.1567%	39.5592%	19.3140%	21.2161%	4.5966%
5	Rate of Return (Ln 1 / Ln 3)	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%	6.32%

PART B

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
6	Change in NOI (Miller Sch 18, Pg 1, Col 2, Ln 20)	$2,190,759							
7	Allocated on NOI Ratio (Ln 2)	$2,190,758	$335,494	$293,617	$573,029	$866,647	$423,123	$464,794	$100,700
8	Annualized NOI (Ln 1 + Ln 7)	$51,222,986	$7,844,324	$6,865,184	$13,398,224	$20,263,409	$9,893,202	$10,867,537	$2,354,514
9	Annualized Rate of Return (Ln 8 / Ln 3)	6.60%	6.60%	6.60%	6.60%	6.60%	6.60%	6.60%	6.60%

PART C

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
10	NOI After All Adjustments and Increase	$64,208,734 *							
11	Allocated on NOI Ratio	$64,208,735	$9,832,971	$8,605,605	$16,794,863	$25,400,469	$12,401,267	$13,622,611	$2,951,417
12	Final Rate Base After All Adjustments	$670,287,954 #							
13	Allocated on Rate Base Ratio	$670,287,953	$102,648,367	$89,835,660	$175,324,967	$265,160,627	$129,459,337	$142,209,184	$30,810,438
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	9.58%	9.58%	9.58%	9.58%	9.58%	9.58%	9.58%	9.58%

*** Total from Miller Sch 19, Page 1, Column 5, Line 20**
 # Total from Miller Sch 19, Page 1, Column 5, Line 21

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
1	NOI (COS Sch 1, Ln 36)	$17,803,773	$1,228,608	$2,696,670	$5,262,871	$7,959,541	$3,899,589	$3,760,538	$955,496
2	NOI Ratio (Based on Ln 1)	100.0000%	6.9008%	15.1466%	29.5604%	44.7070%	21.9032%	21.1221%	5.3668%
3	Rate Base (COS Sch 1, Ln 38)	$325,326,317	$22,450,219	$49,275,940	$96,167,852	$145,443,792	$71,256,743	$68,715,892	$17,459,672
4	Rate Base Ratio (Based on Ln 3)	100.0000%	6.9008%	15.1466%	29.5604%	44.7070%	21.9032%	21.1221%	5.3668%
5	Rate of Return (Ln 1 / Ln 3)	5.47%	5.47%	5.47%	5.47%	5.47%	5.47%	5.47%	5.47%

PART B

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
6	Change in NOI (Miller Sch 18, Pg 2, Col 2, Ln 20)	($728,413)							
7	Allocated on NOI Ratio (Ln 2)	($728,413)	($50,267)	($110,330)	($215,322)	($325,652)	($159,545)	($153,856)	($39,093)
8	Annualized NOI (Ln 1 + Ln 7)	$17,075,360	$1,178,341	$2,586,340	$5,047,549	$7,633,889	$3,740,044	$3,606,682	$916,403
9	Annualized Rate of Return (Ln 8 / Ln 3)	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%

PART C

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
10	NOI After All Adjustments and Increase	$21,720,770 *							
11	Allocated on NOI Ratio	$21,720,770	$1,498,914	$3,289,963	$6,420,752	$9,710,715	$4,757,535	$4,587,892	$1,165,714
12	Final Rate Base After All Adjustments	$276,231,682 #							
13	Allocated on Rate Base Ratio	$276,231,681	$19,062,281	$41,839,762	$81,655,268	$123,495,030	$60,503,466	$58,346,052	$14,824,852
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	7.86%	7.86%	7.86%	7.86%	7.86%	7.86%	7.86%	7.86%

*** Total from Miller Sch 19, Page 3, Column 5, Line 20**
 # Total from Miller Sch 19, Page 3, Column 5, Line 21

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

				Demand					
				Production			Transmission	Distribution	
	Energy 66.1203% Demand 33.8797%	Total	Customer	Demand	Energy	Combined			Energy
1	NOI (COS Sch 1, Ln 36)	$12,590,205	$40,464	$2,128,007	$4,153,057	$6,281,064	$3,050,767	$2,177,466	$1,040,444
2	NOI Ratio (Based on Ln 1)	100.0000%	0.3214%	16.9021%	32.9864%	49.8885%	24.2313%	17.2949%	8.2639%
3	Rate Base (COS Sch 1, Ln 38)	$161,595,895	$519,363	$27,313,068	$53,304,698	$80,617,766	$39,156,741	$27,947,880	$13,354,146
4	Rate Base Ratio (Based on Ln 3)	100.0000%	0.3214%	16.9021%	32.9864%	49.8885%	24.2313%	17.2949%	8.2639%
5	Rate of Return (Ln 1 / Ln 3)	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%

PART B

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
6	Change in NOI (Miller Sch 18, Pg 3, Col 2, Ln 20)	($2,802,675)							
7	Allocated on NOI Ratio (Ln 2)	($2,802,675)	($9,008)	($473,710)	($924,502)	($1,398,212)	($679,124)	($484,720)	($231,611)
8	Annualized NOI (Ln 1 + Ln 7)	$9,787,531	$31,456	$1,654,297	$3,228,555	$4,882,852	$2,371,643	$1,692,746	$808,833
9	Annualized Rate of Return (Ln 8 / Ln 3)	6.06%	6.06%	6.06%	6.06%	6.06%	6.06%	6.06%	6.06%

PART C

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
10	NOI After All Adjustments and Increase	$10,211,829 *							
11	Allocated on NOI Ratio	$10,211,829	$32,820	$1,726,012	$3,368,516	$5,094,528	$2,474,456	$1,766,128	$843,897
12	Final Rate Base After All Adjustments	$134,818,588 #							
13	Allocated on Rate Base Ratio	$134,818,589	$433,302	$22,787,146	$44,471,823	$67,258,969	$32,668,259	$23,316,767	$11,141,292
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	7.57%	7.57%	7.57%	7.57%	7.57%	7.57%	7.57%	7.57%

*** Total from Miller Sch 19, Page 5, Column 5, Line 20**
 # Total from Miller Sch 19, Page 5, Column 5, Line 21

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
1	NOI (COS Sch 1, Ln 36)	$3,311,263	$1,054	$691,135	$1,348,832	$2,039,967	$1,000,245	$0	$269,997
2	NOI Ratio (Based on Ln 1)	100.0000%	0.0318%	20.8722%	40.7347%	61.6069%	30.2074%	0.0000%	8.1539%
3	Rate Base (COS Sch 1, Ln 38)	$202,505,925	$64,490	$42,267,540	$82,490,129	$124,757,669	$61,171,654	$0	$16,512,112
4	Rate Base Ratio (Based on Ln 3)	100.0000%	0.0318%	20.8722%	40.7347%	61.6069%	30.2073%	0.0000%	8.1539%
5	Rate of Return (Ln 1 / Ln 3)	1.64%	1.63%	1.64%	1.64%	1.64%	1.64%	#DIV/0!	1.64%

PART B

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
6	Change in NOI (Miller Sch 18, Pg 4, Col 2, Ln 20)	$417,578							
7	Allocated on NOI Ratio (Ln 2)	$417,578	$133	$87,158	$170,099	$257,257	$126,139	$0	$34,049
8	Annualized NOI (Ln 1 + Ln 7)	$3,728,841	$1,187	$778,293	$1,518,931	$2,297,224	$1,126,384	$0	$304,046
9	Annualized Rate of Return (Ln 8 / Ln 3)	1.84%	1.84%	1.84%	1.84%	1.84%	1.84%	#DIV/0!	1.84%

PART C

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
10	NOI After All Adjustments and Increase	$4,126,529 *							
11	Allocated on NOI Ratio	$4,126,529	$1,314	$861,299	$1,680,928	$2,542,227	$1,246,515	$0	$336,473
12	Final Rate Base After All Adjustments	$160,374,867 #							
13	Allocated on Rate Base Ratio	$160,374,866	$51,073	$33,473,841	$65,328,180	$98,802,020	$48,444,982	$0	$13,076,791
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	#DIV/0!	2.57%

*** Total from Miller Sch 19, Page 7, Column 5, Line 20**
 # Total from Miller Sch 19, Page 7, Column 5, Line 21

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	NOI (COS Sch 1, Ln 36)	$3,655,654	$2,545	$662,513	$1,292,974	$1,955,487	$960,544	$497,126	$239,952
2	NOI Ratio (Based on Ln 1)	100.0000%	0.0696%	18.1230%	35.3692%	53.4921%	26.2756%	13.5988%	6.5639%
3	Rate Base (COS Sch 1, Ln 38)	$91,027,589	$63,377	$16,496,913	$32,195,687	$48,692,600	$23,918,007	$12,378,672	$5,974,933
4	Rate Base Ratio (Based on Ln 3)	100.0000%	0.0696%	18.1230%	35.3692%	53.4921%	26.2756%	13.5988%	6.5639%
5	Rate of Return (Ln 1 / Ln 3)	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%

PART B

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
6	Change in NOI (Miller Sch 18, Pg 5, Col 2, Ln 20)	($1,465,457)							
7	Allocated on NOI Ratio (Ln 2)	($1,465,457)	($1,020)	($265,584)	($518,320)	($783,904)	($385,057)	($199,285)	($96,191)
8	Annualized NOI (Ln 1 + Ln 7)	$2,190,197	$1,525	$396,929	$774,654	$1,171,583	$575,487	$297,841	$143,761
9	Annualized Rate of Return (Ln 8 / Ln 3)	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%

PART C

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
10	NOI After All Adjustments and Increase	$2,000,469 *							
11	Allocated on NOI Ratio	$2,000,468	$1,393	$362,544	$707,549	$1,070,093	$525,634	$272,040	$131,308
12	Final Rate Base After All Adjustments	$74,779,120 #							
13	Allocated on Rate Base Ratio	$74,779,120	$52,065	$13,552,206	$26,448,741	$40,000,947	$19,648,631	$10,169,073	$4,908,404
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	2.68%	2.68%	2.68%	2.68%	2.68%	2.68%	2.68%	2.68%

*** Total from Miller Sch 19, Page 9, Column 5, Line 20**
 # Total from Miller Sch 19, Page 9, Column 5, Line 21

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
1	NOI (COS Sch 1, Ln 36)	$298,326	$234,721	$10,749	$20,978	$31,727	$15,649	$11,702	$4,527
2	NOI Ratio (Based on Ln 1)	100.0000%	78.6794%	3.6031%	7.0319%	10.6350%	5.2456%	3.9226%	1.5175%
3	Rate Base (COS Sch 1, Ln 38)	$38,511,976	$30,300,920	$1,387,631	$2,708,127	$4,095,758	$2,020,212	$1,510,687	$584,399
4	Rate Base Ratio (Based on Ln 3)	100.0000%	78.6792%	3.6031%	7.0319%	10.6350%	5.2457%	3.9226%	1.5174%
5	Rate of Return (Ln 1 / Ln 3)	0.77%	0.77%	0.77%	0.77%	0.77%	0.77%	0.77%	0.77%

PART B

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
6	Change in NOI (Miller Sch 18, Pg 6, Col 2, Ln 20)	($15,711)							
7	Allocated on NOI Ratio (Ln 2)	($15,710)	($12,361)	($566)	($1,105)	($1,671)	($824)	($616)	($238)
8	Annualized NOI (Ln 1 + Ln 7)	$282,615	$222,360	$10,183	$19,873	$30,056	$14,825	$11,086	$4,289
9	Annualized Rate of Return (Ln 8 / Ln 3)	0.73%	0.73%	0.73%	0.73%	0.73%	0.73%	0.73%	0.73%

PART C

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
10	NOI After All Adjustments and Increase	$1,440,377 *							
11	Allocated on NOI Ratio	$1,440,377	$1,133,280	$51,898	$101,286	$153,184	$75,556	$56,500	$21,857
12	Final Rate Base After All Adjustments	$36,628,541 #							
13	Allocated on Rate Base Ratio	$36,628,541	$28,819,048	$1,319,769	$2,575,686	$3,895,454	$1,921,413	$1,436,807	$555,819
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	3.93%	3.93%	3.93%	3.93%	3.93%	3.93%	3.93%	3.93%

*** Total from Miller Sch 19, Page 11, Column 5, Line 20**
 # Total from Miller Sch 19, Page 11, Column 5, Line 21

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	NOI (COS Sch 1, Ln 36)	$11,808	$6,325	$964	$1,882	$2,846	$1,387	$844	$406
2	NOI Ratio (Based on Ln 1)	100.0000%	53.5654%	8.1640%	15.9383%	24.1023%	11.7463%	7.1477%	3.4383%
3	Rate Base (COS Sch 1, Ln 38)	$221,825	$118,821	$18,113	$35,349	$53,462	$26,052	$15,861	$7,629
4	Rate Base Ratio (Based on Ln 3)	100.0000%	53.5652%	8.1654%	15.9355%	24.1010%	11.7444%	7.1502%	3.4392%
5	Rate of Return (Ln 1 / Ln 3)	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%	5.32%

PART B

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
6	Change in NOI (Miller Sch 18, Pg 7, Col 2, Ln 20)	($2,297)							
7	Allocated on NOI Ratio (Ln 2)	($2,297)	($1,230)	($188)	($366)	($554)	($270)	($164)	($79)
8	Annualized NOI (Ln 1 + Ln 7)	$9,511	$5,095	$776	$1,516	$2,292	$1,117	$680	$327
9	Annualized Rate of Return (Ln 8 / Ln 3)	4.29%	4.29%	4.28%	4.29%	4.29%	4.29%	4.29%	4.29%

PART C

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
10	NOI After All Adjustments and Increase	$16,018 *							
11	Allocated on NOI Ratio	$16,019	$8,580	$1,308	$2,553	$3,861	$1,882	$1,145	$551
12	Final Rate Base After All Adjustments	$205,598 #							
13	Allocated on Rate Base Ratio	$205,598	$110,129	$16,788	$32,763	$49,551	$24,146	$14,701	$7,071
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%

*** Total from Miller Sch 19, Page 13, Column 5, Line 20**
 # Total from Miller Sch 19, Page 13, Column 5, Line 21

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

Ln		Total	Customer	Demand - Production Demand	Demand - Production Energy	Demand - Production Combined	Demand - Transmission	Demand - Distribution	Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$192,922,212	$26,197,214	$15,918,666	$31,067,168	$46,985,834	$17,381,891	$29,106,689	$73,250,583
2	NOI (COS Sch 1, Ln 36)	$49,032,227	$7,508,830	$6,571,567	$12,825,195	$19,396,762	$9,470,079	$10,402,743	$2,253,814
3	NOI Ratio (Based on Ln 1)	100.0000%	15.3141%	13.4025%	26.1567%	39.5592%	19.3140%	21.2161%	4.5966%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($60,621,360)							($60,621,360)
5	Removal of Rider Revenues (on NOI Ratio)	($2,842,691)	($435,332)	($380,993)	($743,553)	($1,124,546)	($549,037)	($603,109)	($130,667)
6	Removal of Facilities Charges (on NOI Ratio)	($96)	($15)	($13)	($25)	($38)	($19)	($20)	($4)
7	Removal of Load Management (assigned to production)	$35		$12	$23	$35			
8	COS Per Books Base Rate Revenue	$129,458,100	$25,761,868	$15,537,672	$30,323,613	$45,861,285	$16,832,836	$28,503,560	$12,498,552

PART B

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

Ln		Total	Customer	Demand - Production Demand	Demand - Production Energy	Demand - Production Combined	Demand - Transmission	Demand - Distribution	Energy
9	Annualized Rate Revenue Adjustment	$2,985,398							
10	Allocated on NOI Ratio (Ln 3)	$2,985,398	$457,186	$400,119	$780,881	$1,181,000	$576,599	$633,386	$137,227
11	Total Revenues (Ln 8 + Ln 10)	$132,443,498	$26,219,054	$15,937,791	$31,104,493	$47,042,285	$17,409,435	$29,136,946	$12,635,779
12	Annualized Billing Units		1,296,996	1,520,481,017	1,520,481,017	1,520,481,017	1,520,481,017	1,520,481,017	1,520,481,017
13	Unit Costs based on Annualized Revenues		$20.22 per month	$0.010482 per kWh	$0.020457 per kWh	$0.030939 per kWh	$0.011450 per kWh	$0.019163 per kWh	$0.008310 per kWh

PART C

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

Ln		Total	Customer	Demand - Production Demand	Demand - Production Energy	Demand - Production Combined	Demand - Transmission	Demand - Distribution	Energy
14	Fully Adjusted Rate Revenue Adjustment	11,085,819							
15	Allocated on NOI Ratio (Ln 3)	11,085,819	1,697,690	1,485,782	$2,899,680	4,385,462	2,141,114	2,351,982	509,570
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$140,543,919	$27,459,558	$17,023,454	$33,223,293	$50,246,747	$18,973,949	$30,855,542	$13,008,122
17	Fully Adjusted Billing Units		1,317,564	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840
18	Unit Costs based on Fully Adjusted Cost of Service		$20.84 per month	$0.010490 per kWh	$0.020473 per kWh	$0.030964 per kWh	$0.011692 per kWh	$0.019014 per kWh	$0.008016 per kWh

PART D

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

Ln		Total	Customer	Demand - Production Demand	Demand - Production Energy	Demand - Production Combined	Demand - Transmission	Demand - Distribution	Energy
19	Proposed Rate Revenue Adjustment	$30,043,524							
20	Allocated on NOI Ratio (Ln 3)	$30,043,524	$4,600,886	$4,026,597	$7,858,384	$11,884,981	$5,802,603	$6,374,074	$1,380,980
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$170,587,442	$32,060,444	$21,050,051	$41,081,677	$62,131,728	$24,776,552	$37,229,616	$14,389,102
22	Fully Adjusted Billing Units		1,317,564	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840
23	Unit Costs based on Proposed Revenue Requirement		$24.33 per month	$0.012972 per kWh	$0.025316 per kWh	$0.038288 per kWh	$0.015268 per kWh	$0.022942 per kWh	$0.008867 per kWh

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$82,094,138	$5,238,993	$6,991,303	$13,644,357	$20,635,660	$7,446,983	$13,089,788	$35,682,713
2	NOI (COS Sch 1, Ln 36)	$17,803,773	$1,228,608	$2,696,670	$5,262,871	$7,959,541	$3,899,589	$3,760,538	$955,496
3	NOI Ratio (Based on Ln 1)	100.0000%	6.9008%	15.1466%	29.5604%	44.7070%	21.9032%	21.1221%	5.3668%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($29,697,669)							($29,697,669)
5	Removal of Rider Revenues (on NOI Ratio)	($1,325,418)	($91,465)	($200,756)	($391,799)	($592,555)	($290,308)	($279,957)	($71,133)
6	Removal of Facilities Charges (on NOI Ratio)	($616,355)	($42,534)	($93,357)	($182,197)	($275,554)	($135,001)	($130,187)	($33,079)
7	Removal of Load Management (assigned to production)	$17		$6	$11	$17			
8	COS Per Books Base Rate Revenue	$50,454,714	$5,104,995	$6,697,196	$13,070,372	$19,767,568	$7,021,673	$12,679,644	$5,880,833

PART B

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
9	Annualized Rate Revenue Adjustment	($981,350)							
10	Allocated on NOI Ratio (Ln 3)	($981,350)	($67,721)	($148,641)	($290,091)	($438,733)	($214,947)	($207,282)	($52,667)
11	Total Revenues (Ln 8 + Ln 10)	$49,473,363	$5,037,274	$6,548,554	$12,780,281	$19,328,835	$6,806,727	$12,472,362	$5,828,166
12	Annualized Billing Units		217,116	745,580,278	745,580,278	745,580,278	745,580,278	745,580,278	745,580,278
13	Unit Costs based on Annualized Revenues		$23.20 per month	$0.008783 per kWh	$0.017141 per kWh	$0.025925 per kWh	$0.009129 per kWh	$0.016728 per kWh	$0.007817 per kWh

PART C

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
14	Fully Adjusted Rate Revenue Adjustment	$16,293							
15	Allocated on NOI Ratio (Ln 3)	$16,293	$1,124	$2,468	$4,816	$7,284	$3,569	$3,441	$874
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$50,471,007	$5,106,119	$6,699,663	$13,075,188	$19,774,852	$7,025,242	$12,683,086	$5,881,708
17	Fully Adjusted Billing Units		221,052	761,872,918	761,872,918	761,872,918	761,872,918	761,872,918	761,872,918
18	Unit Costs based on Fully Adjusted Cost of Service		$23.10 per month	$0.008794 per kWh	$0.017162 per kWh	$0.025956 per kWh	$0.009221 per kWh	$0.016647 per kWh	$0.007720 per kWh

PART D

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
19	Proposed Rate Revenue Adjustment	$12,973,749							
20	Allocated on NOI Ratio (Ln 3)	$12,973,749	$895,296	$1,965,085	$3,835,096	$5,800,180	$2,841,661	$2,740,334	$696,278
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$63,444,756	$6,001,416	$8,664,748	$16,910,284	$25,575,032	$9,866,903	$15,423,420	$6,577,985
22	Fully Adjusted Billing Units		221,052	761,872,918	761,872,918	761,872,918	761,872,918	761,872,918	761,872,918
23	Unit Costs based on Proposed Revenue Requirement		$27.15 per month	$0.011373 per kWh	$0.022196 per kWh	$0.033569 per kWh	$0.012951 per kWh	$0.020244 per kWh	$0.008634 per kWh

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

Ln		Total	Customer	Demand - Production Demand	Demand - Production Energy	Demand - Production Combined	Demand - Transmission	Demand - Distribution	Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$53,092,030	$132,196	$4,715,919	$9,203,677	$13,919,596	$5,324,076	$6,031,404	$27,684,759
2	NOI (COS Sch 1, Ln 36)	$12,590,205	$40,464	$2,128,007	$4,153,057	$6,281,064	$3,050,767	$2,177,466	$1,040,444
3	NOI Ratio (Based on Ln 1)	100.0000%	0.3214%	16.9021%	32.9864%	49.8885%	24.2313%	17.2949%	8.2639%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($22,690,325)							($22,690,325)
5	Removal of Rider Revenues (on NOI Ratio)	($436,077)	($1,402)	($73,706)	($143,846)	($217,552)	($105,667)	($75,419)	($36,037)
6	Removal of Facilities Charges (on NOI Ratio)	($418,566)	($1,345)	($70,746)	($138,070)	($208,816)	($101,424)	($72,391)	($34,590)
7	Removal of Load Management (assigned to production)	$9		$3	$6	$9			
8	COS Per Books Base Rate Revenue	$29,547,072	$129,450	$4,571,470	$8,921,767	$13,493,236	$5,116,985	$5,883,594	$4,923,807

PART B

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

Ln		Total	Customer	Demand - Production Demand	Demand - Production Energy	Demand - Production Combined	Demand - Transmission	Demand - Distribution	Energy
9	Annualized Rate Revenue Adjustment	($3,832,401)							
10	Allocated on NOI Ratio (Ln 3)	($3,832,401)	($12,317)	($647,756)	($1,264,172)	($1,911,927)	($928,639)	($662,811)	($316,706)
11	Total Revenues (Ln 8 + Ln 10)	$25,714,671	$117,132	$3,923,714	$7,657,595	$11,581,309	$4,188,345	$5,220,783	$4,607,101
12	Annualized Billing Units		660	1,248,843	572,194,905	1,248,843	1,349,735	1,349,735	572,194,905
13	Unit Costs based on Annualized Revenues		$177.47 per month	$3.141879 per kW	$0.013383 per kWh	$9.273631 per kW	$3.103087 per kW	$3.868006 per kW	$0.008052 per kWh

PART C

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

Ln		Total	Customer	Demand - Production Demand	Demand - Production Energy	Demand - Production Combined	Demand - Transmission	Demand - Distribution	Energy
14	Fully Adjusted Rate Revenue Adjustment	($4,374,050)							
15	Allocated on NOI Ratio (Ln 3)	($4,374,050)	($14,058)	($739,306)	($1,442,842)	($2,182,148)	($1,059,888)	($756,488)	($361,468)
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$25,173,022	$115,392	$3,832,164	$7,478,924	$11,311,088	$4,057,097	$5,127,105	$4,562,339
17	Fully Adjusted Billing Units		672	1,228,152	562,714,493	1,228,152	1,327,372	1,327,372	562,714,493
18	Unit Costs based on Fully Adjusted Cost of Service		$171.71 per month	$3.120269 per kW	$0.013291 per kWh	$9.209844 per kW	$3.056488 per kW	$3.862599 per kW	$0.008108 per kWh

PART D

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

Ln		Total	Customer	Demand - Production Demand	Demand - Production Energy	Demand - Production Combined	Demand - Transmission	Demand - Distribution	Energy
19	Proposed Rate Revenue Adjustment	$5,414,139							
20	Allocated on NOI Ratio (Ln 3)	$5,414,139	$17,401	$915,102	$1,785,930	$2,701,033	$1,311,915	$936,371	$447,420
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$30,587,161	$132,792	$4,747,266	$9,264,855	$14,012,121	$5,369,012	$6,063,476	$5,009,759
22	Fully Adjusted Billing Units		672	1,228,152	562,714,493	1,228,152	1,327,372	1,327,372	562,714,493
23	Unit Costs based on Proposed Revenue Requirement		$197.61 per month	$3.865374 per kW	$0.016465 per kWh	$11.409110 per kW	$4.044843 per kW	$4.568031 per kW	$0.008903 per kWh

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

		Total	Customer	Demand - Production - Demand	Demand - Production - Energy	Demand - Production - Combined	Demand - Transmission	Demand - Distribution	Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$47,382,196	$10,711	$3,801,518	$7,419,115	$11,220,633	$3,207,939	$0	$32,942,913
2	NOI (COS Sch 1, Ln 36)	$3,311,263	$1,054	$691,135	$1,348,832	$2,039,967	$1,000,245	$0	$269,997
3	NOI Ratio (Based on Ln 1)	100.0000%	0.0318%	20.8722%	40.7347%	61.6069%	30.2074%	0.0000%	8.1539%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($28,135,491)							($28,135,491)
5	Removal of Rider Revenues (on NOI Ratio)	$0	$0	$0	$0	$0	$0	$0	$0
6	Removal of Facilities Charges (on NOI Ratio)	($7,479)	($2)	($1,561)	($3,047)	($4,608)	($2,259)	$0	($610)
7	Removal of Load Management (assigned to production)	$14		$5	$9	$14			
8	COS Per Books Base Rate Revenue	$19,239,240	$10,709	$3,799,962	$7,416,078	$11,216,040	$3,205,680	$0	$4,806,812

PART B

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

		Total	Customer	Demand - Production - Demand	Demand - Production - Energy	Demand - Production - Combined	Demand - Transmission	Demand - Distribution	Energy
9	Annualized Rate Revenue Adjustment	$566,062							
10	Allocated on NOI Ratio (Ln 3)	$566,062	$180	$118,150	$230,584	$348,734	$170,992	$0	$46,156
11	Total Revenues (Ln 8 + Ln 10)	$19,805,303	$10,889	$3,918,112	$7,646,662	$11,564,773	$3,376,672	$0	$4,852,968
12	Annualized Billing Units		12	2,037,077	657,936,799	657,936,799	2,037,077	2,037,077	657,936,799
13	Unit Costs based on Annualized Revenues		$907.40 per month	$1.923399 per kW	$0.011622 per kWh	$0.017577 per kWh	$1.657607 per kW	$0.000000 per kW	$0.007376 per kWh

PART C

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

		Total	Customer	Demand - Production - Demand	Demand - Production - Energy	Demand - Production - Combined	Demand - Transmission	Demand - Distribution	Energy
14	Fully Adjusted Rate Revenue Adjustment	$2,783,416							
15	Allocated on NOI Ratio (Ln 3)	$2,783,416	$886	$580,962	$1,133,815	$1,714,777	$840,796	$0	$226,957
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$22,022,657	$11,595	$4,380,923	$8,549,893	$12,930,817	$4,046,476	$0	$5,033,769
17	Fully Adjusted Billing Units		12	2,265,143	731,597,816	731,597,816	2,265,143	2,265,143	731,597,816
18	Unit Costs based on Fully Adjusted Cost of Service		$966.22 per month	$1.934060 per kW	$0.011687 per kWh	$0.017675 per kWh	$1.786411 per kW	$0.000000 per kW	$0.006881 per kWh

PART D

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

		Total	Customer	Demand - Production - Demand	Demand - Production - Energy	Demand - Production - Combined	Demand - Transmission	Demand - Distribution	Energy
19	Proposed Rate Revenue Adjustment	$4,460,689							
20	Allocated on NOI Ratio (Ln 3)	$4,460,689	$1,420	$931,046	$1,817,047	$2,748,093	$1,347,456	$0	$363,720
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$26,483,346	$13,014	$5,311,969	$10,366,940	$15,678,910	$5,393,932	$0	$5,397,489
22	Fully Adjusted Billing Units		12	2,265,143	731,597,816	731,597,816	2,265,143	2,265,143	731,597,816
23	Unit Costs based on Proposed Revenue Requirement		$1,084.54 per month	$2.345092 per kW	$0.014170 per kWh	$0.021431 per kWh	$2.381277 per kW	$0.000000 per kW	$0.007378 per kWh

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

		Total	Customer	Demand - Production Demand	Demand - Production Energy	Demand - Production Combined	Demand - Transmission	Demand - Distribution	Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$21,960,945	$12,824	$2,018,163	$3,938,684	$5,956,847	$2,026,944	$1,863,537	$12,100,793
2	NOI (COS Sch 1, Ln 36)	$3,655,654	$2,545	$662,513	$1,292,974	$1,955,487	$960,544	$497,126	$239,952
3	NOI Ratio (Based on Ln 1)	100.0000%	0.0696%	18.1230%	35.3692%	53.4921%	26.2756%	13.5988%	6.5639%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($10,169,761)							($10,169,761)
5	Removal of Rider Revenues (on NOI Ratio)	($223)	($0)	($40)	($79)	($119)	($59)	($30)	($15)
6	Removal of Facilities Charges (on NOI Ratio)	($222,433)	($155)	($40,311)	($78,673)	($118,984)	($58,446)	($30,248)	($14,600)
7	Removal of Load Management (assigned to production)	$6		$2	$4	$6			
8	COS Per Books Base Rate Revenue	$11,568,533	$12,669	$1,977,813	$3,859,936	$5,837,749	$1,968,440	$1,833,258	$1,916,417

PART B

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

		Total	Customer	Demand - Production Demand	Demand - Production Energy	Demand - Production Combined	Demand - Transmission	Demand - Distribution	Energy
9	Annualized Rate Revenue Adjustment	($1,984,819)							
10	Allocated on NOI Ratio (Ln 3)	($1,984,819)	($1,382)	($359,708)	($702,014)	($1,061,722)	($521,522)	($269,912)	($130,281)
11	Total Revenues (Ln 8 + Ln 10)	$9,583,714	$11,287	$1,618,105	$3,157,923	$4,776,028	$1,446,918	$1,563,346	$1,786,136
12	Annualized Billing Units		36	96,466,999	159,019,895	255,486,894	636,467	636,467	255,486,894
13	Unit Costs based on Annualized Revenues		$313.52 per month	$0.016774 per kWh	$0.019859 per kWh	$0.018694 per kWh	$2.273359 per kW	$2.456288 per kW	$0.006991 per kWh

PART C

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

		Total	Customer	Demand - Production Demand	Demand - Production Energy	Demand - Production Combined	Demand - Transmission	Demand - Distribution	Energy
14	Fully Adjusted Rate Revenue Adjustment	($1,743,878)							
15	Allocated on NOI Ratio (Ln 3)	($1,743,878)	($1,214)	($316,043)	($616,795)	($932,838)	($458,214)	($237,147)	($114,466)
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$9,824,655	$11,454	$1,661,770	$3,243,141	$4,904,912	$1,510,226	$1,596,111	$1,801,951
17	Fully Adjusted Billing Units		36	98,893,555	163,019,923	261,913,478	652,477	652,477	261,913,478
18	Unit Costs based on Fully Adjusted Cost of Service		$318.18 per month	$0.016804 per kWh	$0.019894 per kWh	$0.018727 per kWh	$2.314605 per kW	$2.446234 per kW	$0.006880 per kWh

PART D

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

		Total	Customer	Demand - Production Demand	Demand - Production Energy	Demand - Production Combined	Demand - Transmission	Demand - Distribution	Energy
19	Proposed Rate Revenue Adjustment	$1,990,617							
20	Allocated on NOI Ratio (Ln 3)	$1,990,617	$1,386	$360,759	$704,065	$1,064,824	$523,046	$270,700	$130,662
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$11,815,272	$12,840	$2,022,529	$3,947,206	$5,969,735	$2,033,272	$1,866,812	$1,932,613
22	Fully Adjusted Billing Units		36	98,893,555	163,019,923	261,913,478	652,477	652,477	261,913,478
23	Unit Costs based on Proposed Revenue Requirement		$356.68 per month	$0.020452 per kWh	$0.024213 per kWh	$0.022793 per kWh	$3.116236 per kW	$2.861115 per kW	$0.007379 per kWh

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$6,091,377	$4,467,750	$109,237	$213,190	$322,427	$82,356	$156,719	$1,062,125
2	NOI (COS Sch 1, Ln 36)	$298,326	$234,721	$10,749	$20,978	$31,727	$15,649	$11,702	$4,527
3	NOI Ratio (Based on Ln 1)	100.0000%	78.6794%	3.6031%	7.0319%	10.6350%	5.2456%	3.9226%	1.5175%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($913,313)							($913,313)
5	Removal of Rider Revenues (on NOI Ratio)	$0	$0	$0	$0	$0	$0	$0	$0
6	Removal of Facilities Charges (on NOI Ratio)	$0	$0	$0	$0	$0	$0	$0	$0
7	Removal of Load Management (assigned to production)	$0		$0	$0	$0			
8	COS Per Books Base Rate Revenue	$5,178,064	$4,467,750	$109,237	$213,190	$322,427	$82,356	$156,719	$148,812

PART B

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
9	Annualized Rate Revenue Adjustment	($21,320)							
10	Allocated on NOI Ratio (Ln 3)	($21,320)	($16,774)	($768)	($1,499)	($2,267)	($1,118)	($836)	($324)
11	Total Revenues (Ln 8 + Ln 10)	$5,156,745	$4,450,976	$108,469	$211,691	$320,160	$81,238	$155,883	$148,488
12	Annualized Billing Units		347,796	21,480,264	21,480,264	21,480,264	21,480,264	21,480,264	21,480,264
13	Unit Costs based on Annualized Revenues		$12.80 per month	$0.005050 per kWh	$0.009855 per kWh	$0.014905 per kWh	$0.003782 per kWh	$0.007257 per kWh	$0.006913 per kWh

PART C

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
14	Fully Adjusted Rate Revenue Adjustment	$72,663							
15	Allocated on NOI Ratio (Ln 3)	$72,663	$57,171	$2,618	$5,110	$7,728	$3,812	$2,850	$1,103
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$5,250,728	$4,524,921	$111,855	$218,300	$330,155	$86,168	$159,569	$149,915
17	Fully Adjusted Billing Units		318,276	19,657,087	19,657,087	19,657,087	19,657,087	19,657,087	19,657,087
18	Unit Costs based on Fully Adjusted Cost of Service		$14.22 per month	$0.005690 per kWh	$0.011105 per kWh	$0.016796 per kWh	$0.004384 per kWh	$0.008118 per kWh	$0.007626 per kWh

PART D

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
19	Proposed Rate Revenue Adjustment	$2,067,260							
20	Allocated on NOI Ratio (Ln 3)	$2,067,260	$1,626,507	$74,486	$145,368	$219,853	$108,440	$81,089	$31,370
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$7,317,988	$6,151,428	$186,341	$363,668	$550,009	$194,608	$240,659	$181,285
22	Fully Adjusted Billing Units		318,276	19,657,087	19,657,087	19,657,087	19,657,087	19,657,087	19,657,087
23	Unit Costs based on Proposed Revenue Requirement		$19.33 per month	$0.009480 per kWh	$0.018501 per kWh	$0.027980 per kWh	$0.009900 per kWh	$0.012243 per kWh	$0.009222 per kWh

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$67,603	$35,407	$2,526	$4,930	$7,456	$2,670	$2,598	$19,472
2	NOI (COS Sch 1, Ln 36)	$11,808	$6,325	$964	$1,882	$2,846	$1,387	$844	$406
3	NOI Ratio (Based on Ln 1)	100.0000%	53.5654%	8.1640%	15.9383%	24.1023%	11.7463%	7.1477%	3.4383%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($16,290)							($16,290)
5	Removal of Rider Revenues (on NOI Ratio)	$0	$0	$0	$0	$0	$0	$0	$0
6	Removal of Facilities Charges (on NOI Ratio)	$0	$0	$0	$0	$0	$0	$0	$0
7	Removal of Load Management (assigned to production)	$0		$0	$0	$0			
8	COS Per Books Base Rate Revenue	$51,313	$35,407	$2,526	$4,930	$7,456	$2,670	$2,598	$3,182

PART B

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
9	Annualized Rate Revenue Adjustment	($3,109)							
10	Allocated on NOI Ratio (Ln 3)	($3,109)	($1,666)	($254)	($496)	($749)	($365)	($222)	($107)
11	Total Revenues (Ln 8 + Ln 10)	$48,203	$33,741	$2,272	$4,434	$6,707	$2,305	$2,376	$3,075
12	Annualized Billing Units		2,340	465,629	465,629	465,629	465,629	465,629	465,629
13	Unit Costs based on Annualized Revenues		$14.42 per month	$0.004880 per kWh	$0.009523 per kWh	$0.014403 per kWh	$0.004950 per kWh	$0.005102 per kWh	$0.006604 per kWh

PART C

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
14	Fully Adjusted Rate Revenue Adjustment	($352)							
15	Allocated on NOI Ratio (Ln 3)	($352)	($189)	($29)	($56)	($85)	($41)	($25)	($12)
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$50,961	$35,218	$2,497	$4,874	$7,371	$2,629	$2,573	$3,170
17	Fully Adjusted Billing Units		2,352	513,499	513,499	513,499	513,499	513,499	513,499
18	Unit Costs based on Fully Adjusted Cost of Service		$14.97 per month	$0.004863 per kWh	$0.009492 per kWh	$0.014355 per kWh	$0.005119 per kWh	$0.005010 per kWh	$0.006173 per kWh

PART D

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
19	Proposed Rate Revenue Adjustment	$11,468							
20	Allocated on NOI Ratio (Ln 3)	$11,468	$6,143	$936	$1,828	$2,764	$1,347	$820	$394
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$62,429	$41,361	$3,433	$6,702	$10,135	$3,976	$3,393	$3,564
22	Fully Adjusted Billing Units		2,352	513,499	513,499	513,499	513,499	513,499	513,499
23	Unit Costs based on Proposed Revenue Requirement		$17.59 per month	$0.006686 per kWh	$0.013051 per kWh	$0.019737 per kWh	$0.007742 per kWh	$0.006607 per kWh	$0.006941 per kWh

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023

SCHEDULE 1

SCHEDULE 1 - SUMMARY

Line #		NC Jur Total	Residential	SGS,CO & Muni	LGS	Schedule NS	6VP	St & Outdoor Lighting	Traffic Lighting	Allocation Basis
1	Dec 2023									
2										
3	C:[SUMMARY OF RESULTS]									
4	D:[]									
5	E:[OPERATING REVENUES]	408,196,365	195,321,873	82,981,526	53,562,335	47,857,018	22,166,767	6,237,728	69,118	NC Class Schedule 2 - Revenue/Li
6	F:[]									
7	G:[OPERATING EXPENSES]									
8	H:[OPERATION & MAINTENANCE EXPENSES]	239,139,128	104,066,737	49,459,418	31,877,097	36,213,543	13,835,586	3,644,161	42,587	NC Class Schedule 3 - O&M Exper
9	I:[DEPRECIATION EXPENSE]	60,832,913	33,134,104	13,095,805	5,630,668	4,439,623	2,137,195	2,384,367	11,150	NC Class Schedule 4 - Depreciatio
10	J:[AMORT. OF ACQ. AJUSTMENTS]	7,311	3,525	1,669	854	893	323	47	1	NC Class Schedule 4 - Depreciatio
11	K:[AMORT. OF PROP. LOSS & REG STUDY]	83,583	40,292	19,078	9,768	10,213	3,692	534	6	NC Class Schedule 6 - Net Current
12	L:[REGULATORY DEBITS AND CREDITS]	10,909,089	4,895,446	2,346,252	1,414,269	1,604,252	579,864	68,035	970	NC Class Schedule 6 - Net Current
13	N:[GAIN/LOSS ON DISPOSITION OF ALLOWANCES]	(89,091)	(35,475)	(17,379)	(13,278)	(16,464)	(5,951)	(534)	(10)	NC Class Schedule 6 - Net Current
14	O:[GAIN / LOSS ON DISPOSITION OF PROPERTY]	245,242	131,572	53,270	24,128	19,910	9,282	7,042	38	NC Class Schedule 6 - Net Current
15	Q:[ACCRETION EXPENSE - ARO]	5,133,919	2,114,449	1,029,287	738,692	897,110	324,267	29,524	589	NC Class Schedule 22 - Other Alloc
16	R:[FEDERAL INCOME TAX]									
17	S:[INVESTMENT TAX CREDIT - AMORTIZATION]	141,040	67,989	32,193	16,483	17,234	6,229	902	11	NC Class Schedule 7 - Income Tax
18	T:[FEDERAL NET CURRENT TAX]	6,833,874	3,332,221	578,990	1,946,458	500,658	826,784	(352,297)	1,061	NC Class Schedule 6 - Net Current
19	U:[FEDERAL INCOME TAX DEFERRED]	(3,208,237)	(905,759)	(436,386)	(664,235)	(855,089)	(340,139)	(6,185)	(443)	NC Class Schedule 7 - Income Tax
20	W:[STATE INCOME TAX CURRENT]	483,103	289,336	64,909	106,173	(2,147)	39,975	(15,221)	77	NC Class Schedule 6 - Net Current
21	X:[STATE INCOME TAX DEFERRED]	1,812,324	1,085,422	243,502	398,300	(8,053)	149,961	(57,099)	291	NC Class Schedule 7 - Income Tax
22	Y:[TAXES OTHER THAN INCOME TAX]	12,635,649	6,822,082	2,768,439	1,222,114	988,309	464,982	367,585	2,138	NC Class Schedule 5 - Other Taxes
23	Z:[TOTAL ELECTRIC OPERATING EXPENSES]	334,959,847	155,041,941	69,239,046	42,707,492	43,809,992	18,032,049	6,070,862	58,466	
24	AA:[]									
25	AB:[NET OPERATING INCOME]	73,236,518	40,279,932	13,742,480	10,854,843	4,047,026	4,134,719	166,867	10,652	
26	AC:[]									
27	AD:[ADJUSTMENTS TO OPERATING INCOME]									
28	AE:[ADD: ALLOWANCE FOR FUNDS]	14,108,009	6,857,031	3,200,675	1,630,435	1,680,808	618,848	119,034	1,177	NC Class Schedule 8 - Other Adjus
29	AF:[]									
30	AG:[DEDUCT: CHARITABLE & EDUCATIONAL]									
31	AH:[DONATIONS]	397,631	173,038	82,239	53,004	60,214	23,005	6,059	71	NC Class Schedule 8 - Other Adjus
32	AI:[DONATIONS - ASSIGNED]	0	0	0	0	0	0	0	0	NC Class Schedule 8 - Other Adjus
33	AJ:[INTEREST EXPENSE - CUST. DEPOSITS]	31,017	14,826	6,309	4,080	3,641	1,688	468	5	NC Class Schedule 8 - Other Adjus
34	AK:[OTHER INTEREST EXPENSE]	212,619	111,474	46,679	21,744	18,831	8,488	5,372	31	NC Class Schedule 8 - Other Adjus
35	AL:[TOTAL DEDUCTIONS]	641,268	299,339	135,227	78,829	82,686	33,181	11,900	107	
36	AM:[]									
37	AN:[ADJUSTED NET ELEC. OPERATING INCOME]	86,703,259	46,837,624	16,807,928	12,406,450	5,645,147	4,720,386	274,001	11,722	
38	AO:[]									
39	AP:[RATE BASE]	1,594,851,513	828,551,058	349,325,773	166,024,329	146,260,248	65,367,989	39,098,214	223,901	NC Class Schedule 1 - Summary/L
40	AQ:[]									
41	AR:[ROR EARNED ON RATE BASE (Including Ringfenced as applic	5.4364%	5.6530%	4.8115%	7.4727%	3.8597%	7.2213%	0.7008%	5.2355%	
42	AS:[]									
43	AV:[SYSTEM RATE OF RETURN (Excluding Ringfenced as applicat	5.4364%	5.4364%	5.4364%	5.4364%	5.4364%	5.4364%	5.4364%	5.4364%	
44	AW:[INDEX RATE OF RETURN (PRESENT) (AQ/AU)]	1.00	1.04	0.89	1.37	0.71	1.33	0.13	0.96	
45	AX:[]									

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023

SCHEDULE 1

SCHEDULE 1 - SUMMARY

Line #		NC Jur Total	Residential	SGS,CO & Muni	LGS	Schedule NS	6VP	St & Outdoor Lighting	Traffic Lighting	Allocation Basis
46	AY:[]									
47	AZ:[]									
48	BA:[RATE BASE]									
49	BB:[PLANT INVESTMENT]									
50	BC:[ELECTRIC PLANT INCL. NUCLEAR FUEL]	2,269,147,992	1,217,395,476	492,895,048	223,248,837	184,219,217	85,880,084	65,160,594	348,737	NC Class Schedule 10 - Plant in Ser
51	BD:[ACQUISITION ADJUSTMENTS]	313,057	150,911	71,456	36,585	38,253	13,827	2,001	24	NC Class Schedule 10 - Plant in Ser
52	BE:[ELECTRIC CWIP INCL FUEL]	360,345,332	176,169,569	80,084,134	41,640,385	42,304,161	15,997,253	4,115,514	34,316	NC Class Schedule 12 - Constructio
53	BF:[PLANT HELD FOR FUTURE USE]	0	0	0	0	0	0	0	0	NC Class Schedule 13 - Plant Held
54	BG:[TOTAL PLANT INVESTMENT]	2,629,806,381	1,393,715,955	573,050,637	264,925,808	226,561,631	101,891,163	69,278,109	383,078	
55	BH:[]									
56	BI:[DEDUCT:]									
57	BJ:[ACCUM. PROV. FOR DEPREC. & AMORT]	(778,067,179)	(429,874,761)	(167,884,168)	(72,948,981)	(57,212,678)	(26,470,998)	(23,558,926)	(116,667)	NC Class Schedule 11 - Accum Dep
58	BK:[AMORT OF NUCLEAR FUEL]	(55,694,591)	(22,176,751)	(10,864,121)	(8,300,666)	(10,292,639)	(3,720,343)	(334,112)	(5,959)	NC Class Schedule 11 - Accum Dep
59	BL:[ACQUISITION ADJ. FOR DEPREC. RESERVE]	(53,457)	(25,769)	(12,202)	(6,247)	(6,532)	(2,361)	(342)	(4)	NC Class Schedule 11 - Accum Dep
60	BM:[TOTAL DEPRECIATION & AMORTIZATION]	(833,815,226)	(452,077,281)	(178,760,490)	(81,255,894)	(67,511,849)	(30,193,702)	(23,893,380)	(122,630)	
61	BN:[]									
62	BO:[NET PLANT]	1,795,991,155	941,638,674	394,290,147	183,669,914	159,049,782	71,697,461	45,384,729	260,447	
63	BP:[]									
64	BQ:[DEDUCT:]									
65	BS:[ACCUMULATED DEFERRED INCOME TAXES]	185,445,996	92,300,407	39,221,972	20,832,729	20,451,464	8,500,863	4,112,600	25,961	NC Class Schedule 23 - Cost Free C
67	BW:[CUSTOMER DEPOSITS]	3,135,948	1,498,955	637,850	412,511	368,147	170,631	47,328	525	NC Class Schedule 14 - Working Ca
68	BX:[EXCESS DEFERRED INCOME TAXES]	107,582,689	57,893,843	23,544,330	10,521,259	8,557,459	4,009,741	3,040,734	15,324	NC Class Schedule 23 - Cost Free C
69	BY:[]									
70	BZ:[ADD: WORKING CAPITAL]									
71	CA:[MATERIAL & SUPPLIES]	50,733,308	24,420,376	10,742,441	6,007,089	6,203,692	2,465,605	887,995	6,109	NC Class Schedule 14 - Working Ca
73	CC:[INVESTOR FUNDS ADVANCED]	15,791,563	7,557,659	3,210,038	2,072,000	1,850,114	857,463	241,611	2,676	NC Class Schedule 14 - Working Ca
74	CD:[TOTAL ADDITIONS]	264,540,117	111,543,276	53,464,574	37,085,442	44,244,227	16,148,655	2,025,876	28,066	NC Class Schedule 14 - Working Ca
78	CH:[TOTAL DEDUCTIONS]	(236,039,996)	(104,915,722)	(48,977,275)	(31,043,617)	(35,710,497)	(13,119,962)	(2,241,335)	(31,587)	NC Class Schedule 14 - Working Ca
80	CJ:[DEFERRED FUEL]	0	0	0	0	0	0	0	0	NC Class Schedule 14 - Working Ca
82	CL:[TOTAL ALLOWANCE FOR WORK CAPITAL]	95,024,991	38,605,589	18,439,778	14,120,915	16,587,537	6,351,761	914,147	5,264	
83	CM:[]									
84	CN:[TOTAL RATE BASE]	1,594,851,513	828,551,058	349,325,773	166,024,329	146,260,248	65,367,989	39,098,214	223,901	
85	CO:[]									

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**Residential Class** **Annualized Cost of Service Summary** DESCRIPTION	(1) Residential Cost of Service	(2) Annualized Revenue Adjustment	(3) Residential Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$129,458,157	$2,964,557	$132,422,713
2	Forfeited Discounts and Miscellaneous Service Revenues	$761,746	$5,147	$766,892
3	Non-Fuel Rider Revenues	$2,842,691	$0	$2,842,691
4	Fuel Revenues	$60,621,360	$0	$60,621,360
5	Other Operating Revenues	$1,637,919	$0	$1,637,919
6	TOTAL OPERATING REVENUES	$195,321,873	$2,969,704	$198,291,576
	OPERATING EXPENSES			
7	Fuel Expense	$61,522,679		$61,522,679
8	Non-Fuel Operating and Maintenance Expense	$42,544,058	$21,629	$42,565,686
9	Depreciation and Amortization	$40,187,816		$40,187,816
10	Federal Income Tax	$2,494,451	$582,546	$3,076,998
11	State Income Tax	$1,374,758	$169,696	$1,544,454
12	Taxes Other than Income Tax	$6,822,082	$4,348	$6,826,431
13	(Gain)/Loss on Disposition of Property	$96,097		$96,097
14	TOTAL ELECTRIC OPERATING EXPENSES	$155,041,941	$778,220	$155,820,161
15	**NET OPERATING INCOME**	$40,279,932	$2,191,484	$42,471,415
	ADJUSTMENTS TO OPERATING INCOME			
16	*ADD:* AFUDC	$6,857,031		$6,857,031
17	*LESS:* Charitable Donations	$173,038		$173,038
18	Interest Expense on Customer Deposits	$14,826		$14,826
19	Other Interest Expense/(Income)	$111,474		$111,474
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$46,837,624	$2,191,484	$49,029,107
21	**RATE BASE (from Line 38 below)**	$828,551,058	$0	$828,551,058
22	**ROR EARNED ON AVERAGE RATE BASE**	5.6530%		5.9175%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$24,420,376		$24,420,376
24	Investor Funds Advanced	$7,557,659		$7,557,659
25	Total Additions	$111,543,276		$111,543,276
26	Total Deductions	($104,915,722)		($104,915,722)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$38,605,589	$0	$38,605,589
	NET UTILITY PLANT			
28	Utility Plant in Service	$1,217,395,476		$1,217,395,476
29	Acquisition Adjustments	$150,911		$150,911
30	Construction Work in Progress	$176,169,569		$176,169,569
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$452,051,512		$452,051,512
32	Provision for Acquisition Adjustments	$25,769		$25,769
33	TOTAL NET UTILITY PLANT	$941,638,674	$0	$941,638,674
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$1,498,955		$1,498,955
35	Accumulated Deferred Income Taxes	$92,300,407		$92,300,407
36	Other Cost Free Capital	$57,893,843		$57,893,843
37	TOTAL RATE BASE DEDUCTIONS	$151,693,205	$0	$151,693,205
38	**TOTAL RATE BASE**	$828,551,058	$0	$828,551,058

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**SGS & Public Authorities Class** **Annualized Cost of Service Summary** DESCRIPTION	(1) SGS Cost of Service	(2) Annualized Revenue Adjustment	(3) SGS Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load			
1	Management	$51,071,050	($988,825)	$50,082,226
2	Forfeited Discounts and Miscellaneous Service Revenues	$210,233	$2,190	$212,423
3	Non-Fuel Rider Revenues	$1,325,418	$0	
4	Fuel Revenues	$29,697,669	$0	$29,697,669
5	Other Operating Revenues	$677,157	$0	$677,157
6	TOTAL OPERATING REVENUES	$82,981,526	($986,634)	$81,994,891
	OPERATING EXPENSES			
7	Fuel Expense	$30,139,214		$30,139,214
8	Non-Fuel Operating and Maintenance Expense	$19,320,203	($7,186)	$19,313,018
9	Depreciation and Amortization	$16,492,091		$16,492,091
10	Federal Income Tax	$174,796	($193,541)	($18,745)
11	State Income Tax	$308,411	($56,379)	$252,032
12	Taxes Other than Income Tax	$2,768,439	($1,445)	$2,766,994
13	(Gain)/Loss on Disposition of Property	$35,892		$35,892
14	TOTAL ELECTRIC OPERATING EXPENSES	$69,239,046	($258,551)	$68,980,495
15	**NET OPERATING INCOME**	$13,742,480	($728,084)	$13,014,396
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$3,200,675		$3,200,675
17	LESS: Charitable Donations	$82,239		$82,239
18	Interest Expense on Customer Deposits	$6,309		$6,309
19	Other Interest Expense/(Income)	$46,679		$46,679
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$16,807,928	($728,084)	$16,079,844
21	**RATE BASE (from Line 38 below)**	$349,325,773	$0	$349,325,773
22	**ROR EARNED ON AVERAGE RATE BASE**	4.8115%		4.6031%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$10,742,441		$10,742,441
24	Investor Funds Advanced	$3,210,038		$3,210,038
25	Total Additions	$53,464,574		$53,464,574
26	Total Deductions	($48,977,275)		($48,977,275)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$18,439,778	$0	$18,439,778
	NET UTILITY PLANT			
28	Utility Plant in Service	$492,895,048		$492,895,048
29	Acquisition Adjustments	$71,456		$71,456
30	Construction Work in Progress	$80,084,134		$80,084,134
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$178,748,289		$178,748,289
32	Provision for Acquisition Adjustments	$12,202		$12,202
33	TOTAL NET UTILITY PLANT	$394,290,147	$0	$394,290,147
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$637,850		$637,850
35	Accumulated Deferred Income Taxes	$39,221,972		$39,221,972
36	Other Cost Free Capital	$23,544,330		$23,544,330
37	TOTAL RATE BASE DEDUCTIONS	$63,404,151	$0	$63,404,151
38	**TOTAL RATE BASE**	$349,325,773	$0	$349,325,773

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**LGS Class** **Annualized Cost of Service Summary** DESCRIPTION	(1) LGS Cost of Service	(2) Annualized Revenue Adjustment	(3) LGS Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load			
1	Management	$29,965,628	($3,799,269)	$26,166,359
2	Forfeited Discounts and Miscellaneous Service Revenues	$88,823	$1,416	$90,240
3	Non-Fuel Rider Revenues	$436,077	$0	
4	Fuel Revenues	$22,690,325	$0	$22,690,325
5	Other Operating Revenues	$381,483	$0	$381,483
6	TOTAL OPERATING REVENUES	$53,562,335	($3,797,853)	$49,764,482
	OPERATING EXPENSES			
7	Fuel Expense	$23,027,685		$23,027,685
8	Non-Fuel Operating and Maintenance Expense	$8,849,412	($27,660)	$8,821,752
9	Depreciation and Amortization	$7,794,253		$7,794,253
10	Federal Income Tax	$1,298,705	($744,999)	$553,707
11	State Income Tax	$504,474	($217,019)	$287,455
12	Taxes Other than Income Tax	$1,222,114	($5,561)	$1,216,553
13	(Gain)/Loss on Disposition of Property	$10,850		$10,850
14	TOTAL ELECTRIC OPERATING EXPENSES	$42,707,492	($995,239)	$41,712,253
15	**NET OPERATING INCOME**	$10,854,843	($2,802,614)	$8,052,229
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$1,630,435		$1,630,435
17	LESS: Charitable Donations	$53,004		$53,004
18	Interest Expense on Customer Deposits	$4,080		$4,080
19	Other Interest Expense/(Income)	$21,744		$21,744
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$12,406,450	($2,802,614)	$9,603,836
21	**RATE BASE (from Line 38 below)**	$166,024,329	$0	$166,024,329
22	**ROR EARNED ON AVERAGE RATE BASE**	7.4727%		5.7846%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$6,007,089		$6,007,089
24	Investor Funds Advanced	$2,072,000		$2,072,000
25	Total Additions	$37,085,442		$37,085,442
26	Total Deductions	($31,043,617)		($31,043,617)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$14,120,915	$0	$14,120,915
	NET UTILITY PLANT			
28	Utility Plant in Service	$223,248,837		$223,248,837
29	Acquisition Adjustments	$36,585		$36,585
30	Construction Work in Progress	$41,640,385		$41,640,385
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$81,249,647		$81,249,647
32	Provision for Acquisition Adjustments	$6,247		$6,247
33	TOTAL NET UTILITY PLANT	$183,669,914	$0	$183,669,914
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$412,511		$412,511
35	Accumulated Deferred Income Taxes	$20,832,729		$20,832,729
36	Other Cost Free Capital	$10,521,259		$10,521,259
37	TOTAL RATE BASE DEDUCTIONS	$31,766,499	$0	$31,766,499
38	**TOTAL RATE BASE**	$166,024,329	$0	$166,024,329

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

Schedule NS Class
Annualized Cost of Service Summary

LINE NO.	DESCRIPTION	(1) Sched NS Cost of Service	(2) Annualized Revenue Adjustment	(3) Sched NS Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$19,246,708	$563,556	$19,810,264
2	Forfeited Discounts and Miscellaneous Service Revenues	$79,098	$1,264	$80,362
3	Non-Fuel Rider Revenues	$0	$0	
4	Fuel Revenues	$28,135,491	$0	$28,135,491
5	Other Operating Revenues	$395,720	$0	$395,720
6	TOTAL OPERATING REVENUES	$47,857,018	$564,820	$48,421,837
	OPERATING EXPENSES			
7	Fuel Expense	$28,553,810		$28,553,810
8	Non-Fuel Operating and Maintenance Expense	$7,659,734	$4,114	$7,663,847
9	Depreciation and Amortization	$6,952,091		$6,952,091
10	Federal Income Tax	($337,197)	$110,797	($226,400)
11	State Income Tax	($10,200)	$32,275	$22,076
12	Taxes Other than Income Tax	$988,309	$827	$989,136
13	(Gain)/Loss on Disposition of Property	$3,445		$3,445
14	TOTAL ELECTRIC OPERATING EXPENSES	$43,809,992	$148,013	$43,958,005
15	**NET OPERATING INCOME**	$4,047,026	$416,807	$4,463,833
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$1,680,808		$1,680,808
17	LESS: Charitable Donations	$60,214		$60,214
18	Interest Expense on Customer Deposits	$3,641		$3,641
19	Other Interest Expense/(Income)	$18,831		$18,831
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$5,645,147	$416,807	$6,061,954
21	**RATE BASE (from Line 38 below)**	$146,260,248	$0	$146,260,248
22	**ROR EARNED ON AVERAGE RATE BASE**	3.8597%		4.1446%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$6,203,692		$6,203,692
24	Investor Funds Advanced	$1,850,114		$1,850,114
25	Total Additions	$44,244,227		$44,244,227
26	Total Deductions	($35,710,497)		($35,710,497)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$16,587,537	$0	$16,587,537
	NET UTILITY PLANT			
28	Utility Plant in Service	$184,219,217		$184,219,217
29	Acquisition Adjustments	$38,253		$38,253
30	Construction Work in Progress	$42,304,161		$42,304,161
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$67,505,317		$67,505,317
32	Provision for Acquisition Adjustments	$6,532		$6,532
33	TOTAL NET UTILITY PLANT	$159,049,782	$0	$159,049,782
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$368,147		$368,147
35	Accumulated Deferred Income Taxes	$20,451,464		$20,451,464
36	Other Cost Free Capital	$8,557,459		$8,557,459
37	TOTAL RATE BASE DEDUCTIONS	$29,377,071	$0	$29,377,071
38	**TOTAL RATE BASE**	$146,260,248	$0	$146,260,248

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**6VP Class** **Annualized Cost of Service Summary** DESCRIPTION	(1) 6VP Cost of Service	(2) Annualized Revenue Adjustment	(3) 6VP Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load			
1	Management	$11,790,963	($1,986,920)	$9,804,043
2	Forfeited Discounts and Miscellaneous Service Revenues	$36,671	$586	$37,257
3	Non-Fuel Rider Revenues	$223	$0	
4	Fuel Revenues	$10,169,761	$0	$10,169,761
5	Other Operating Revenues	$169,149	$0	$169,149
6	TOTAL OPERATING REVENUES	$22,166,767	($1,986,334)	$20,180,433
	OPERATING EXPENSES			
7	Fuel Expense	$10,320,965		$10,320,965
8	Non-Fuel Operating and Maintenance Expense	$3,514,621	($14,467)	$3,500,154
9	Depreciation and Amortization	$3,045,340		$3,045,340
10	Federal Income Tax	$492,874	($389,645)	$103,229
11	State Income Tax	$189,936	($113,504)	$76,432
12	Taxes Other than Income Tax	$464,982	($2,909)	$462,073
13	(Gain)/Loss on Disposition of Property	$3,330		$3,330
14	TOTAL ELECTRIC OPERATING EXPENSES	$18,032,049	($520,525)	$17,511,524
15	**NET OPERATING INCOME**	$4,134,719	($1,465,809)	$2,668,909
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$618,848		$618,848
17	LESS: Charitable Donations	$23,005		$23,005
18	Interest Expense on Customer Deposits	$1,688		$1,688
19	Other Interest Expense/(Income)	$8,488		$8,488
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$4,720,386	($1,465,809)	$3,254,577
21	**RATE BASE (from Line 38 below)**	$65,367,989	$0	$65,367,989
22	**ROR EARNED ON AVERAGE RATE BASE**	7.2213%		4.9789%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$2,465,605		$2,465,605
24	Investor Funds Advanced	$857,463		$857,463
25	Total Additions	$16,148,655		$16,148,655
26	Total Deductions	($13,119,962)		($13,119,962)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$6,351,761	$0	$6,351,761
	NET UTILITY PLANT			
28	Utility Plant in Service	$85,880,084		$85,880,084
29	Acquisition Adjustments	$13,827		$13,827
30	Construction Work in Progress	$15,997,253		$15,997,253
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$30,191,341		$30,191,341
32	Provision for Acquisition Adjustments	$2,361		$2,361
33	TOTAL NET UTILITY PLANT	$71,697,461	$0	$71,697,461
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$170,631		$170,631
35	Accumulated Deferred Income Taxes	$8,500,863		$8,500,863
36	Other Cost Free Capital	$4,009,741		$4,009,741
37	TOTAL RATE BASE DEDUCTIONS	$12,681,234	$0	$12,681,234
38	**TOTAL RATE BASE**	$65,367,989	$0	$65,367,989

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**Street and Outdoor Lighting Class** **Annualized Cost of Service Summary** DESCRIPTION	(1) Street & Outdoor Lighting Cost of Service	(2) Annualized Revenue Adjustment	(3) Street & Outdoor Lighting COS Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$5,178,063	($21,441)	$5,156,622
2	Forfeited Discounts and Miscellaneous Service Revenues	$76,019	$163	$76,182
3	Non-Fuel Rider Revenues	$0	$0	
4	Fuel Revenues	$913,313	$0	$913,313
5	Other Operating Revenues	$70,333	$0	$70,333
6	TOTAL OPERATING REVENUES	$6,237,728	($21,279)	$6,216,450
	OPERATING EXPENSES			
7	Fuel Expense	$926,892		$926,892
8	Non-Fuel Operating and Maintenance Expense	$2,717,268	($155)	$2,717,113
9	Depreciation and Amortization	$2,482,508		$2,482,508
10	Federal Income Tax	($357,581)	($4,174)	($361,755)
11	State Income Tax	($72,319)	($1,216)	($73,535)
12	Taxes Other than Income Tax	$367,585	($31)	$367,554
13	(Gain)/Loss on Disposition of Property	$6,508		$6,508
14	TOTAL ELECTRIC OPERATING EXPENSES	$6,070,862	($5,576)	$6,065,285
15	**NET OPERATING INCOME**	$166,867	($15,703)	$151,164
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$119,034		$119,034
17	LESS: Charitable Donations	$6,059		$6,059
18	Interest Expense on Customer Deposits	$468		$468
19	Other Interest Expense/(Income)	$5,372		$5,372
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$274,001	($15,703)	$258,299
21	**RATE BASE (from Line 38 below)**	$39,098,214	$0	$39,098,214
22	**ROR EARNED ON AVERAGE RATE BASE**	0.7008%		0.6606%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$887,995		$887,995
24	Investor Funds Advanced	$241,611		$241,611
25	Total Additions	$2,025,876		$2,025,876
26	Total Deductions	($2,241,335)		($2,241,335)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$914,147	$0	$914,147
	NET UTILITY PLANT			
28	Utility Plant in Service	$65,160,594		$65,160,594
29	Acquisition Adjustments	$2,001		$2,001
30	Construction Work in Progress	$4,115,514		$4,115,514
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$23,893,038		$23,893,038
32	Provision for Acquisition Adjustments	$342		$342
33	TOTAL NET UTILITY PLANT	$45,384,729	$0	$45,384,729
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$47,328		$47,328
35	Accumulated Deferred Income Taxes	$4,112,600		$4,112,600
36	Other Cost Free Capital	$3,040,734		$3,040,734
37	TOTAL RATE BASE DEDUCTIONS	$7,200,662	$0	$7,200,662
38	**TOTAL RATE BASE**	$39,098,214	$0	$39,098,214

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

Traffic Lighting Class
Annualized Cost of Service Summary

LINE NO.	DESCRIPTION	(1) Traffic Lighting Cost of Service	(2) Annualized Revenue Adjustment	(3) Traffic Lighting Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$51,314	($3,115)	$48,199
2	Forfeited Discounts and Miscellaneous Service Revenues	$899	$2	$901
3	Non-Fuel Rider Revenues	$0	$0	
4	Fuel Revenues	$16,290	$0	$16,290
5	Other Operating Revenues	$615	$0	$615
6	TOTAL OPERATING REVENUES	$69,118	($3,113)	$66,005
	OPERATING EXPENSES			
7	Fuel Expense	$16,532		$16,532
8	Non-Fuel Operating and Maintenance Expense	$26,055	($23)	$26,032
9	Depreciation and Amortization	$12,716		$12,716
10	Federal Income Tax	$629	($611)	$18
11	State Income Tax	$368	($178)	$190
12	Taxes Other than Income Tax	$2,138	($5)	$2,134
13	(Gain)/Loss on Disposition of Property	$28		$28
14	TOTAL ELECTRIC OPERATING EXPENSES	$58,466	($816)	$57,650
15	**NET OPERATING INCOME**	$10,652	($2,297)	$8,355
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$1,177		$1,177
17	LESS: Charitable Donations	$71		$71
18	Interest Expense on Customer Deposits	$5		$5
19	Other Interest Expense/(Income)	$31		$31
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$11,722	($2,297)	$9,425
21	**RATE BASE (from Line 38 below)**	$223,901	$0	$223,901
22	**ROR EARNED ON AVERAGE RATE BASE**	5.2355%		4.2095%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$6,109		$6,109
24	Investor Funds Advanced	$2,676		$2,676
25	Total Additions	$28,066		$28,066
26	Total Deductions	($31,587)		($31,587)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$5,264	$0	$5,264
	NET UTILITY PLANT			
28	Utility Plant in Service	$348,737		$348,737
29	Acquisition Adjustments	$24		$24
30	Construction Work in Progress	$34,316		$34,316
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$122,626		$122,626
32	Provision for Acquisition Adjustments	$4		$4
33	TOTAL NET UTILITY PLANT	$260,447	$0	$260,447
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$525		$525
35	Accumulated Deferred Income Taxes	$25,961		$25,961
36	Other Cost Free Capital	$15,324		$15,324
37	TOTAL RATE BASE DEDUCTIONS	$41,811	$0	$41,811
38	**TOTAL RATE BASE**	$223,901	$0	$223,901

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
ANNUALIZED COST OF SERVICE BASED ON RATES IN EFFECT DECEMBER 31, 2023
SHOWING EFFECTS OF ANNUALIZING BASE RATE NON-FUEL REVENUES

LINE NO.	**Total of All North Carolina Classes** **Annualized Cost of Service Summary** DESCRIPTION	(1) Total Cost of Service	(2) Annualized Revenue Adjustment	(3) Total Cost of Service Adjusted for Annualized Revenue (Col 1 + Col 2)
	OPERATING REVENUES			
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$246,761,884	($3,271,458)	$243,490,427
2	Forfeited Discounts and Miscellaneous Service Revenues	$1,253,489	$10,768	$1,264,257
3	Non-Fuel Rider Revenues	$4,604,409	$0	$4,604,409
4	Fuel Revenues	$152,244,208	$0	$152,244,208
5	Other Operating Revenues	$3,332,375	$0	$3,332,375
6	TOTAL OPERATING REVENUES	$408,196,365	($3,260,690)	$404,935,675
	OPERATING EXPENSES			
7	Fuel Expense	$154,507,777	$0	$154,507,777
8	Non-Fuel Operating and Maintenance Expense	$84,631,351	($23,748)	$84,607,603
9	Depreciation and Amortization	$76,966,815	$0	$76,966,815
10	Federal Income Tax	$3,766,678	($639,627)	$3,127,051
11	State Income Tax	$2,295,427	($186,324)	$2,109,103
12	Taxes Other than Income Tax	$12,635,649	($4,774)	$12,630,875
13	(Gain)/Loss on Disposition of Property	$156,151	$0	$156,151
14	TOTAL ELECTRIC OPERATING EXPENSES	$334,959,847	($854,474)	$334,105,374
15	**NET OPERATING INCOME**	$73,236,518	($2,406,216)	$70,830,302
	ADJUSTMENTS TO OPERATING INCOME			
16	ADD: AFUDC	$14,108,009	$0	$14,108,009
17	LESS: Charitable Donations	$397,631	$0	$397,631
18	Interest Expense on Customer Deposits	$31,017	$0	$31,017
19	Other Interest Expense/(Income)	$212,619	$0	$212,619
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$86,703,259	($2,406,216)	$84,297,043
21	**RATE BASE (from Line 38 below)**	$1,594,851,513	$0	$1,594,851,513
22	**ROR EARNED ON AVERAGE RATE BASE**	5.4364%		5.2856%
	ALLOWANCE FOR WORKING CAPITAL			
23	Materials and Supplies	$50,733,308	$0	$50,733,308
24	Investor Funds Advanced	$15,791,563	$0	$15,791,563
25	Total Additions	$264,540,117	$0	$264,540,117
26	Total Deductions	($236,039,996)	$0	($236,039,996)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$95,024,991	$0	$95,024,991
	NET UTILITY PLANT			
28	Utility Plant in Service	$2,269,147,992	$0	$2,269,147,992
29	Acquisition Adjustments	$313,057	$0	$313,057
30	Construction Work in Progress	$360,345,332	$0	$360,345,332
	LESS:			
31	Accumulated Provision for Depreciation & Amortization	$833,761,769	$0	$833,761,769
32	Provision for Acquisition Adjustments	$53,457	$0	$53,457
33	TOTAL NET UTILITY PLANT	$1,795,991,155	$0	$1,795,991,155
	RATE BASE DEDUCTIONS			
34	Customer Deposits	$3,135,948	$0	$3,135,948
35	Accumulated Deferred Income Taxes	$185,445,996	$0	$185,445,996
36	Other Cost Free Capital	$107,582,689	$0	$107,582,689
37	TOTAL RATE BASE DEDUCTIONS	$296,164,633	$0	$296,164,633
38	**TOTAL RATE BASE**	$1,594,851,513	$0	$1,594,851,513

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

Residential Class
Fully Adjusted Cost of Service and Revenue Requirement
Adjusted Net Operating Income and Rate of Return

LINE NO.	DESCRIPTION	(1) Residential Cost of Service	(2) Ratemaking Adjustments	(3) Residential Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) Residential Base Non-Fuel Additional Revenue Requirement	(5) Residential Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	OPERATING REVENUES					
	Base Non-Fuel Rate Revenues, Including Facilities Charges &					
1	Load Management	$129,458,157	$11,065,439	$140,523,596	$30,040,916	$170,564,512
2	Forfeited Discounts and Misc. Service Revenues	$761,746	$27,665	$789,410	($164,523)	$624,888
3	Non-Fuel Rider Revenues	$2,842,691	($2,842,691)	$0		$0
4	Fuel Revenues	$60,621,360	($6,088,841)	$54,532,519		$54,532,519
5	Other Operating Revenues	$1,637,919	($1,406)	$1,636,513		$1,636,513
6	TOTAL OPERATING REVENUES	$195,321,873	$2,160,166	$197,482,039	$29,876,393	$227,358,432
	OPERATING EXPENSES					
7	Fuel Expense	$61,522,679	($7,070,595)	$54,452,084		$54,452,084
8	Non-Fuel Operating and Maintenance Expense	$42,544,058	$8,937,389	$51,481,446	$261,342	$51,742,788
9	Depreciation and Amortization	$40,187,816	$262,685	$40,450,501		$40,450,501
10	Federal Income Tax	$2,494,451	$852,531	$3,346,983	$5,860,646	$9,207,629
11	State Income Tax	$1,374,758	$247,922	$1,622,680	$1,707,213	$3,329,892
12	Taxes Other than Income Tax	$6,822,082	$271,349	$7,093,431		$7,093,431
13	(Gain)/Loss on Disposition of Property	$96,097	($131,572)	($35,475)		($35,475)
14	TOTAL ELECTRIC OPERATING EXPENSES	$155,041,941	$3,369,709	$158,411,650	$7,829,201	$166,240,851
15	**NET OPERATING INCOME**	$40,279,932	($1,209,543)	$39,070,389	$22,047,192	$61,117,581
	ADJUSTMENTS TO OPERATING INCOME					
16	*ADD:* AFUDC	$6,857,031	($6,857,031)	$0		$0
17	*LESS:* Charitable Donations	$173,038	($173,038)	$0		$0
18	Interest Expense on Customer Deposits	$14,826		$14,826		$14,826
19	Other Interest Expense/(Income)	$111,474		$111,474		$111,474
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$46,837,624	($7,893,536)	$38,944,088	$22,047,192	$60,991,280
21	**RATE BASE (from Line 38 below)**	$828,551,058	($127,994,580)	$700,556,479	$10,571,351	$711,127,830
22	**ROR EARNED ON AVERAGE RATE BASE**	5.6530%		5.5590%		8.5767%

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Residential Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Rate Base** DESCRIPTION	**(1)** **Residential Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **Residential Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **Residential Base Non-Fuel Additional Revenue Requirement**	**(5)** **Residential Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$24,420,376	$0	$24,420,376		$24,420,376
24	Investor Funds Advanced	$7,557,659	$11,749,325	$19,306,984	$10,571,351	$29,878,335
25	Total Additions	$111,543,276	($87,221,245)	$24,322,031		$24,322,031
26	Total Deductions	($104,915,722)	$86,161,176	($18,754,546)		($18,754,546)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$38,605,589	$10,689,256	$49,294,845	$10,571,351	$59,866,196
	NET UTILITY PLANT					
28	Utility Plant in Service	$1,217,395,476	$48,064,072	$1,265,459,548		$1,265,459,548
29	Acquisition Adjustments	$150,911	($150,910)	$0		$0
30	Construction Work in Progress	$176,169,569	($176,169,569)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$452,051,512	$21,103,333	$473,154,845		$473,154,845
32	Provision for Acquisition Adjustments	$25,769	($25,769)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$941,638,674	($149,333,971)	$792,304,703	$0	$792,304,703
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$1,498,955		$1,498,955		$1,498,955
35	Accumulated Deferred Income Taxes	$92,300,407	($9,706,905)	$82,593,502		$82,593,502
36	Other Cost Free Capital	$57,893,843	($943,230)	$56,950,613		$56,950,613
37	TOTAL RATE BASE DEDUCTIONS	$151,693,205	($10,650,135)	$141,043,070	$0	$141,043,070
38	**TOTAL RATE BASE**	$828,551,058	($127,994,580)	$700,556,479	$10,571,351	$711,127,830

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	DESCRIPTION **Small General Service, County, & Muni Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return**	(1) SGS Cost of Service	(2) Ratemaking Adjustments	(3) SGS Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) SGS Base Non-Fuel Additional Revenue Requirement	(5) SGS Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$51,071,050	$8,984	$51,080,035	$12,811,129	$63,891,163
2	Forfeited Discounts and Misc. Service Revenues	$210,233	$9,925	$220,158	($24,952)	$195,206
3	Non-Fuel Rider Revenues	$1,325,418	($1,325,418)	$0		$0
4	Fuel Revenues	$29,697,669	($2,982,849)	$26,714,819		$26,714,819
5	Other Operating Revenues	$677,157	($1,312)	$675,844		$675,844
6	TOTAL OPERATING REVENUES	$82,981,526	($4,290,670)	$78,690,856	$12,786,177	$91,477,033
	OPERATING EXPENSES					
7	Fuel Expense	$30,139,214	($3,463,799)	$26,675,415		$26,675,415
8	Non-Fuel Operating and Maintenance Expense	$19,320,203	$2,355,975	$21,676,178	$111,846	$21,788,024
9	Depreciation and Amortization	$16,492,091	($29,702)	$16,462,389		$16,462,389
10	Federal Income Tax	$174,796	($268,721)	($93,924)	$2,508,176	$2,414,252
11	State Income Tax	$308,411	($78,478)	$229,933	$730,635	$960,567
12	Taxes Other than Income Tax	$2,768,439	$111,551	$2,879,990		$2,879,990
13	(Gain)/Loss on Disposition of Property	$35,892	($53,270)	($17,379)		($17,379)
14	TOTAL ELECTRIC OPERATING EXPENSES	$69,239,046	($1,426,444)	$67,812,602	$3,350,657	$71,163,259
15	**NET OPERATING INCOME**	$13,742,480	($2,864,226)	$10,878,254	$9,435,520	$20,313,774
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$3,200,675	($3,200,675)	$0		$0
17	LESS: Charitable Donations	$82,239	($82,239)	$0		$0
18	Interest Expense on Customer Deposits	$6,309		$6,309		$6,309
19	Other Interest Expense/(Income)	$46,679		$46,679		$46,679
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$16,807,928	($5,982,661)	$10,825,267	$9,435,520	$20,260,787
21	**RATE BASE (from Line 38 below)**	$349,325,773	($59,367,416)	$289,958,358	$4,805,221	$294,763,578
22	**ROR EARNED ON AVERAGE RATE BASE**	4.8115%		3.7334%		6.8736%

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Small General Service, County, & Muni Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Rate Base** DESCRIPTION	**(1)** **SGS Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **SGS Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **SGS Base Non-Fuel Additional Revenue Requirement**	**(5)** **SGS Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$10,742,441	$0	$10,742,441		$10,742,441
24	Investor Funds Advanced	$3,210,038	$4,991,642	$8,201,680	$4,805,221	$13,006,901
25	Total Additions	$53,464,574	($42,448,688)	$11,015,885		$11,015,885
26	Total Deductions	($48,977,275)	$41,424,300	($7,552,975)		($7,552,975)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$18,439,778	$3,967,254	$22,407,032	$4,805,221	$27,212,253
	NET UTILITY PLANT					
28	Utility Plant in Service	$492,895,048	$19,610,338	$512,505,386		$512,505,386
29	Acquisition Adjustments	$71,456	($71,456)	$0		$0
30	Construction Work in Progress	$80,084,134	($80,084,134)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$178,748,289	$8,351,150	$187,099,439		$187,099,439
32	Provision for Acquisition Adjustments	$12,202	($12,202)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$394,290,147	($68,884,200)	$325,405,947	$0	$325,405,947
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$637,850		$637,850		$637,850
35	Accumulated Deferred Income Taxes	$39,221,972	($5,167,241)	$34,054,730		$34,054,730
36	Other Cost Free Capital	$23,544,330	($382,289)	$23,162,041		$23,162,041
37	TOTAL RATE BASE DEDUCTIONS	$63,404,151	($5,549,530)	$57,854,621	$0	$57,854,621
38	**TOTAL RATE BASE**	$349,325,773	($59,367,416)	$289,958,358	$4,805,221	$294,763,578

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Large General Service Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **LGS Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **LGS Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **LGS Base Non-Fuel Additional Revenue Requirement**	**(5)** **LGS Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$29,965,628	($4,340,796)	$25,624,832	$5,469,866	$31,094,698
2	Forfeited Discounts and Misc. Service Revenues	$88,823	$5,654	$94,477	($14,337)	$80,140
3	Non-Fuel Rider Revenues	$436,077	($436,077)	$0		$0
4	Fuel Revenues	$22,690,325	($2,279,028)	$20,411,297		$20,411,297
5	Other Operating Revenues	$381,483	($5,540)	$375,942		$375,942
6	TOTAL OPERATING REVENUES	$53,562,335	($7,055,787)	$46,506,548	$5,455,529	$51,962,078
	OPERATING EXPENSES					
7	Fuel Expense	$23,027,685	($2,646,495)	$20,381,190		$20,381,190
8	Non-Fuel Operating and Maintenance Expense	$8,849,412	$1,967,756	$10,817,168	$47,722	$10,864,890
9	Depreciation and Amortization	$7,794,253	($114,613)	$7,679,640		$7,679,640
10	Federal Income Tax	$1,298,705	($1,065,722)	$232,984	$1,070,174	$1,303,157
11	State Income Tax	$504,474	($310,548)	$193,925	$311,743	$505,668
12	Taxes Other than Income Tax	$1,222,114	$50,443	$1,272,557		$1,272,557
13	(Gain)/Loss on Disposition of Property	$10,850	($24,128)	($13,278)		($13,278)
14	TOTAL ELECTRIC OPERATING EXPENSES	$42,707,492	($2,143,307)	$40,564,185	$1,429,638	$41,993,824
15	**NET OPERATING INCOME**	$10,854,843	($4,912,480)	$5,942,363	$4,025,891	$9,968,254
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$1,630,435	($1,630,435)	$0		$0
17	LESS: Charitable Donations	$53,004	($53,004)	$0		$0
18	Interest Expense on Customer Deposits	$4,080		$4,080		$4,080
19	Other Interest Expense/(Income)	$21,744		$21,744		$21,744
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$12,406,450	($6,489,912)	$5,916,538	$4,025,891	$9,942,429
21	**RATE BASE (from Line 38 below)**	$166,024,329	($30,863,254)	$135,161,075	$3,077,061	$138,238,136
22	**ROR EARNED ON AVERAGE RATE BASE**	7.4727%		4.3774%		7.1922%

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Large General Service Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Rate Base** DESCRIPTION	**(1)** **LGS Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **LGS Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **LGS Base Non-Fuel Additional Revenue Requirement**	**(5)** **LGS Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	<u>ALLOWANCE FOR WORKING CAPITAL</u>					
23	Materials and Supplies	$6,007,089	$0	$6,007,089		$6,007,089
24	Investor Funds Advanced	$2,072,000	$3,221,970	$5,293,971	$3,077,061	$8,371,032
25	Total Additions	$37,085,442	($30,609,859)	$6,475,583		$6,475,583
26	Total Deductions	($31,043,617)	$27,615,493	($3,428,124)		($3,428,124)
27	<u>TOTAL ALLOWANCE FOR WORKING CAPITAL</u>	$14,120,915	$227,605	$14,348,520	$3,077,061	$17,425,581
	<u>NET UTILITY PLANT</u>					
28	Utility Plant in Service	$223,248,837	$8,943,454	$232,192,291		$232,192,291
29	Acquisition Adjustments	$36,585	($36,585)	$0		$0
30	Construction Work in Progress	$41,640,385	($41,640,385)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$81,249,647	$3,779,607	$85,029,254		$85,029,254
32	Provision for Acquisition Adjustments	$6,247	($6,247)	($0)		($0)
33	<u>TOTAL NET UTILITY PLANT</u>	$183,669,914	($36,506,877)	$147,163,037	$0	$147,163,037
	<u>RATE BASE DEDUCTIONS</u>					
34	Customer Deposits	$412,511		$412,511		$412,511
35	Accumulated Deferred Income Taxes	$20,832,729	($5,245,943)	$15,586,787		$15,586,787
36	Other Cost Free Capital	$10,521,259	($170,075)	$10,351,183		$10,351,183
37	<u>TOTAL RATE BASE DEDUCTIONS</u>	$31,766,499	($5,416,018)	$26,350,481	$0	$26,350,481
38	**<u>TOTAL RATE BASE</u>**	$166,024,329	($30,863,254)	$135,161,075	$3,077,061	$138,238,136

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Schedule NS Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **Schedule NS Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **Schedule NS Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **Schedule NS Base Non-Fuel Additional Revenue Requirement**	**(5)** **Schedule NS Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$19,246,708	$2,780,965	$22,027,673	$4,461,071	$26,488,745
2	Forfeited Discounts and Misc. Service Revenues	$79,098	$5,043	$84,142	($14,866)	$69,275
3	Non-Fuel Rider Revenues	$0	$0	$0		$0
4	Fuel Revenues	$28,135,491	($2,825,943)	$25,309,548		$25,309,548
5	Other Operating Revenues	$395,720	($8,662)	$387,058		$387,058
6	TOTAL OPERATING REVENUES	$47,857,018	($48,597)	$47,808,421	$4,446,205	$52,254,626
	OPERATING EXPENSES					
7	Fuel Expense	$28,553,810	($3,281,594)	$25,272,216		$25,272,216
8	Non-Fuel Operating and Maintenance Expense	$7,659,734	$2,841,152	$10,500,886	$38,893	$10,539,779
9	Depreciation and Amortization	$6,952,091	($226,974)	$6,725,118		$6,725,118
10	Federal Income Tax	($337,197)	$273,510	($63,687)	$872,181	$808,494
11	State Income Tax	($10,200)	$79,567	$69,367	$254,067	$323,435
12	Taxes Other than Income Tax	$988,309	$43,090	$1,031,398		$1,031,398
13	(Gain)/Loss on Disposition of Property	$3,445	($19,910)	($16,464)		($16,464)
14	TOTAL ELECTRIC OPERATING EXPENSES	$43,809,992	($291,159)	$43,518,833	$1,165,142	$44,683,975
15	**NET OPERATING INCOME**	$4,047,026	$242,562	$4,289,588	$3,281,063	$7,570,651
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$1,680,808	($1,680,808)	$0		$0
17	LESS: Charitable Donations	$60,214	($60,214)	$0		$0
18	Interest Expense on Customer Deposits	$3,641		$3,641		$3,641
19	Other Interest Expense/(Income)	$18,831		$18,831		$18,831
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$5,645,147	($1,378,031)	$4,267,116	$3,281,063	$7,548,179
21	**RATE BASE (from Line 38 below)**	$146,260,248	($32,490,454)	$113,769,794	$3,173,295	$116,943,089
22	**ROR EARNED ON AVERAGE RATE BASE**	3.8597%		3.7507%		6.4546%

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Schedule NS Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Rate Base** DESCRIPTION	**(1)** **Schedule NS Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **Schedule NS Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **Schedule NS Base Non-Fuel Additional Revenue Requirement**	**(5)** **Schedule NS Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$6,203,692	$0	$6,203,692		$6,203,692
24	Investor Funds Advanced	$1,850,114	$2,878,775	$4,728,889	$3,173,295	$7,902,184
25	Total Additions	$44,244,227	($37,224,242)	$7,019,986		$7,019,986
26	Total Deductions	($35,710,497)	$32,555,197	($3,155,300)		($3,155,300)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$16,587,537	($1,790,270)	$14,797,266	$3,173,295	$17,970,562
	NET UTILITY PLANT					
28	Utility Plant in Service	$184,219,217	$7,496,965	$191,716,182		$191,716,182
29	Acquisition Adjustments	$38,253	($38,253)	$0		$0
30	Construction Work in Progress	$42,304,161	($42,304,161)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$67,505,317	$3,130,927	$70,636,244		$70,636,244
32	Provision for Acquisition Adjustments	$6,532	($6,532)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$159,049,782	($37,969,844)	$121,079,938	$0	$121,079,938
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$368,147		$368,147		$368,147
35	Accumulated Deferred Income Taxes	$20,451,464	($7,132,591)	$13,318,874		$13,318,874
36	Other Cost Free Capital	$8,557,459	($137,069)	$8,420,390		$8,420,390
37	TOTAL RATE BASE DEDUCTIONS	$29,377,071	($7,269,660)	$22,107,411	$0	$22,107,411
38	**TOTAL RATE BASE**	$146,260,248	($32,490,454)	$113,769,794	$3,173,295	$116,943,089

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	6VP Class Fully Adjusted Cost of Service and Revenue Requirement Adjusted Net Operating Income and Rate of Return DESCRIPTION	(1) 6VP Cost of Service	(2) Ratemaking Adjustments	(3) 6VP Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) 6VP Base Non-Fuel Additional Revenue Requirement	(5) 6VP Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$11,790,963	($1,745,933)	$10,045,031	$2,021,326	$12,066,357
2	Forfeited Discounts and Misc. Service Revenues	$36,671	$2,338	$39,009	($8,098)	$30,911
3	Non-Fuel Rider Revenues	$223	($223)	$0		$0
4	Fuel Revenues	$10,169,761	($1,021,456)	$9,148,305		$9,148,305
5	Other Operating Revenues	$169,149	($3,131)	$166,018		$166,018
6	TOTAL OPERATING REVENUES	$22,166,767	($2,768,405)	$19,398,362	$2,013,228	$21,411,590
	OPERATING EXPENSES					
7	Fuel Expense	$10,320,965	($1,186,154)	$9,134,811		$9,134,811
8	Non-Fuel Operating and Maintenance Expense	$3,514,621	$1,087,945	$4,602,567	$17,611	$4,620,177
9	Depreciation and Amortization	$3,045,340	($50,358)	$2,994,983		$2,994,983
10	Federal Income Tax	$492,874	($449,994)	$42,881	$394,921	$437,802
11	State Income Tax	$189,936	($131,122)	$58,814	$115,041	$173,855
12	Taxes Other than Income Tax	$464,982	$19,312	$484,293		$484,293
13	(Gain)/Loss on Disposition of Property	$3,330	($9,282)	($5,951)		($5,951)
14	TOTAL ELECTRIC OPERATING EXPENSES	$18,032,049	($719,652)	$17,312,397	$527,573	$17,839,969
15	**NET OPERATING INCOME**	$4,134,719	($2,048,753)	$2,085,965	$1,485,655	$3,571,621
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$618,848	($618,848)	$0		$0
17	LESS: Charitable Donations	$23,005	($23,005)	$0		$0
18	Interest Expense on Customer Deposits	$1,688		$1,688		$1,688
19	Other Interest Expense/(Income)	$8,488		$8,488		$8,488
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$4,720,386	($2,644,596)	$2,075,789	$1,485,655	$3,561,445
21	**RATE BASE (from Line 38 below)**	$65,367,989	($11,696,996)	$53,670,993	$1,294,301	$54,965,295
22	**ROR EARNED ON AVERAGE RATE BASE**	7.2213%		3.8676%		6.4794%

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

6VP Class
Fully Adjusted Cost of Service and Revenue Requirement
Rate Base

LINE NO.	DESCRIPTION	(1) 6VP Cost of Service	(2) Ratemaking Adjustments	(3) 6VP Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) 6VP Base Non-Fuel Additional Revenue Requirement	(5) 6VP Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$2,465,605	$0	$2,465,605		$2,465,605
24	Investor Funds Advanced	$857,463	$1,333,412	$2,190,875	$1,294,301	$3,485,177
25	Total Additions	$16,148,655	($13,461,860)	$2,686,795		$2,686,795
26	Total Deductions	($13,119,962)	$11,812,091	($1,307,871)		($1,307,871)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$6,351,761	($316,357)	$6,035,405	$1,294,301	$7,329,706
	NET UTILITY PLANT					
28	Utility Plant in Service	$85,880,084	$3,436,812	$89,316,895		$89,316,895
29	Acquisition Adjustments	$13,827	($13,827)	$0		$0
30	Construction Work in Progress	$15,997,253	($15,997,253)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$30,191,341	$1,407,212	$31,598,552		$31,598,552
32	Provision for Acquisition Adjustments	$2,361	($2,361)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$71,697,461	($13,979,119)	$57,718,343	$0	$57,718,343
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$170,631		$170,631		$170,631
35	Accumulated Deferred Income Taxes	$8,500,863	($2,533,680)	$5,967,183		$5,967,183
36	Other Cost Free Capital	$4,009,741	($64,800)	$3,944,941		$3,944,941
37	TOTAL RATE BASE DEDUCTIONS	$12,681,234	($2,598,480)	$10,082,754	$0	$10,082,754
38	**TOTAL RATE BASE**	$65,367,989	($11,696,996)	$53,670,993	$1,294,301	$54,965,295

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	Street and Outdoor Lighting Class Fully Adjusted Cost of Service and Revenue Requirement Adjusted Net Operating Income and Rate of Return DESCRIPTION	(1) St. & Out. Lighting Cost of Service	(2) Ratemaking Adjustments	(3) St. & Out. Lighting Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) St. & Out. Lighting Base Non-Fuel Additional Revenue Requirement	(5) St. & Out. Lighting Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$5,178,063	$72,544	$5,250,608	$2,067,245	$7,317,853
2	Forfeited Discounts and Misc. Service Revenues	$76,019	$1,716	$77,735	($31,835)	$45,901
3	Non-Fuel Rider Revenues	$0	$0	$0		$0
4	Fuel Revenues	$913,313	($91,734)	$821,579		$821,579
5	Other Operating Revenues	$70,333	($90)	$70,243		$70,243
6	TOTAL OPERATING REVENUES	$6,237,728	($17,563)	$6,220,165	$2,035,411	$8,255,576
	OPERATING EXPENSES					
7	Fuel Expense	$926,892	($106,525)	$820,368		$820,368
8	Non-Fuel Operating and Maintenance Expense	$2,717,268	$239,476	$2,956,744	$17,805	$2,974,549
9	Depreciation and Amortization	$2,482,508	$119,732	$2,602,240		$2,602,240
10	Federal Income Tax	($357,581)	($14,443)	($372,024)	$399,272	$27,249
11	State Income Tax	($72,319)	($4,213)	($76,532)	$116,309	$39,776
12	Taxes Other than Income Tax	$367,585	$13,790	$381,375		$381,375
13	(Gain)/Loss on Disposition of Property	$6,508	($7,042)	($534)		($534)
14	TOTAL ELECTRIC OPERATING EXPENSES	$6,070,862	$240,774	$6,311,636	$533,386	$6,845,022
15	**NET OPERATING INCOME**	$166,867	($258,337)	($91,471)	$1,502,025	$1,410,554
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$119,034	($119,034)	$0		$0
17	LESS: Charitable Donations	$6,059	($6,059)	$0		$0
18	Interest Expense on Customer Deposits	$468		$468		$468
19	Other Interest Expense/(Income)	$5,372		$5,372		$5,372
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$274,001	($371,312)	($97,311)	$1,502,025	$1,404,714
21	**RATE BASE (from Line 38 below)**	$39,098,214	($2,294,562)	$36,803,653	$277,570	$37,081,222
22	**ROR EARNED ON AVERAGE RATE BASE**	0.7008%		-0.2644%		3.7882%

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

Street and Outdoor Lighting Class
Fully Adjusted Cost of Service and Revenue Requirement
Rate Base

LINE NO.	DESCRIPTION	(1) St. & Out. Lighting Cost of Service	(2) Ratemaking Adjustments	(3) St. & Out. Lighting Fully Adjusted Cost of Service (Col 1 + Col 2)	(4) St. & Out. Lighting Base Non-Fuel Additional Revenue Requirement	(5) St. & Out. Lighting Fully Adjusted COS After Added Non-Fuel Base Revenues (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$887,995	$0	$887,995		$887,995
24	Investor Funds Advanced	$241,611	$375,222	$616,833	$277,570	$894,403
25	Total Additions	$2,025,876	($1,304,147)	$721,729		$721,729
26	Total Deductions	($2,241,335)	$1,309,101	($932,234)		($932,234)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$914,147	$380,177	$1,294,324	$277,570	$1,571,893
	NET UTILITY PLANT					
28	Utility Plant in Service	$65,160,594	$2,484,412	$67,645,006		$67,645,006
29	Acquisition Adjustments	$2,001	($2,001)	$0		$0
30	Construction Work in Progress	$4,115,514	($4,115,514)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$23,893,038	$1,148,868	$25,041,906		$25,041,906
32	Provision for Acquisition Adjustments	$342	($342)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$45,384,729	($2,781,630)	$42,603,100	$0	$42,603,100
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$47,328		$47,328		$47,328
35	Accumulated Deferred Income Taxes	$4,112,600	($56,568)	$4,056,032		$4,056,032
36	Other Cost Free Capital	$3,040,734	($50,323)	$2,990,411		$2,990,411
37	TOTAL RATE BASE DEDUCTIONS	$7,200,662	($106,891)	$7,093,771	$0	$7,093,771
38	**TOTAL RATE BASE**	$39,098,214	($2,294,562)	$36,803,653	$277,570	$37,081,222

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Traffic Lighting Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **Traffic Lighting Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **Traffic Lighting Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **Traffic Lighting Base Non-Fuel Additional Revenue Requirement**	**(5)** **Traffic Lighting Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	OPERATING REVENUES					
1	Base Non-Fuel Rate Revenues, Including Facilities Charges & Load Management	$51,314	($357)	$50,957	$11,467	$62,424
2	Forfeited Discounts and Misc. Service Revenues	$899	$20	$919	($436)	$483
3	Non-Fuel Rider Revenues	$0	$0	$0		$0
4	Fuel Revenues	$16,290	($1,636)	$14,654		$14,654
5	Other Operating Revenues	$615	($5)	$610		$610
6	TOTAL OPERATING REVENUES	$69,118	($1,978)	$67,140	$11,031	$78,171
	OPERATING EXPENSES					
7	Fuel Expense	$16,532	($1,900)	$14,632		$14,632
8	Non-Fuel Operating and Maintenance Expense	$26,055	$2,985	$29,040	$96	$29,136
9	Depreciation and Amortization	$12,716	$294	$13,010		$13,010
10	Federal Income Tax	$629	($427)	$202	$2,164	$2,366
11	State Income Tax	$368	($124)	$244	$630	$874
12	Taxes Other than Income Tax	$2,138	$96	$2,234		$2,234
13	(Gain)/Loss on Disposition of Property	$28	($38)	($10)		($10)
14	TOTAL ELECTRIC OPERATING EXPENSES	$58,466	$886	$59,352	$2,891	$62,243
15	**NET OPERATING INCOME**	$10,652	($2,864)	$7,788	$8,140	$15,928
	ADJUSTMENTS TO OPERATING INCOME					
16	ADD: AFUDC	$1,177	($1,177)	$0		$0
17	LESS: Charitable Donations	$71	($71)	$0		$0
18	Interest Expense on Customer Deposits	$5		$5		$5
19	Other Interest Expense/(Income)	$31		$31		$31
20	**ADJUSTED NET ELECTRIC OPERATING INCOME**	$11,722	($3,971)	$7,752	$8,140	$15,892
21	**RATE BASE (from Line 38 below)**	$223,901	($18,761)	$205,139	$2,061	$207,201
22	**ROR EARNED ON AVERAGE RATE BASE**	5.2355%		3.7787%		7.6699%

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Traffic Lighting Class** **Fully Adjusted Cost of Service and Revenue Requirement** **Rate Base** DESCRIPTION	**(1)** **Traffic Lighting Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **Traffic Lighting Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **Traffic Lighting Base Non-Fuel Additional Revenue Requirement**	**(5)** **Traffic Lighting Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$6,109	$0	$6,109		$6,109
24	Investor Funds Advanced	$2,676	$4,158	$6,834	$2,061	$8,895
25	Total Additions	$28,066	($21,831)	$6,235		$6,235
26	Total Deductions	($31,587)	$22,021	($9,566)		($9,566)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$5,264	$4,348	$9,612	$2,061	$11,673
	NET UTILITY PLANT					
28	Utility Plant in Service	$348,737	$13,491	$362,228		$362,228
29	Acquisition Adjustments	$24	($24)	$0		$0
30	Construction Work in Progress	$34,316	($34,316)	$0		$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$122,626	$5,841	$128,467		$128,467
32	Provision for Acquisition Adjustments	$4	($4)	($0)		($0)
33	TOTAL NET UTILITY PLANT	$260,447	($26,686)	$233,761	$0	$233,761
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$525		$525		$525
35	Accumulated Deferred Income Taxes	$25,961	($3,326)	$22,636		$22,636
36	Other Cost Free Capital	$15,324	($252)	$15,073		$15,073
37	TOTAL RATE BASE DEDUCTIONS	$41,811	($3,577)	$38,234	$0	$38,234
38	**TOTAL RATE BASE**	$223,901	($18,761)	$205,139	$2,061	$207,201

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Total of All North Carolina Classes** **Fully Adjusted Cost of Service and Revenue Requirement** **Adjusted Net Operating Income and Rate of Return** DESCRIPTION	**(1)** **Total NC Jurisdiction Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **Total NC Jurisdiction Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **Total NC Jurisdiction Base Non-Fuel Additional Revenue Requirement**	**(5)** **Total NC Jurisdiction Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	<u>OPERATING REVENUES</u>					
	Base Non-Fuel Rate Revenues, Including Facilities Charges &					
1	Load Management	$246,761,884	$7,840,847	$254,602,731	$56,883,021	$311,485,752
2	Forfeited Discounts and Misc. Service Revenues	$1,253,489	$52,361	$1,305,850	($259,047)	$1,046,803
3	Non-Fuel Rider Revenues	$4,604,409	($4,604,409)	$0	$0	$0
4	Fuel Revenues	$152,244,208	($15,291,487)	$136,952,721	$0	$136,952,721
5	Other Operating Revenues	$3,332,375	($20,146)	$3,312,229	$0	$3,312,229
6	<u>TOTAL OPERATING REVENUES</u>	$408,196,365	($12,022,834)	$396,173,531	$56,623,974	$452,797,505
	<u>OPERATING EXPENSES</u>					
7	Fuel Expense	$154,507,777	($17,757,061)	$136,750,716	$0	$136,750,716
8	Non-Fuel Operating and Maintenance Expense	$84,631,351	$17,432,677	$102,064,028	$495,315	$102,559,343
9	Depreciation and Amortization	$76,966,815	($38,935)	$76,927,880	$0	$76,927,880
10	Federal Income Tax	$3,766,678	($673,265)	$3,093,413	$11,107,535	$14,200,947
11	State Income Tax	$2,295,427	($196,997)	$2,098,430	$3,235,638	$5,334,068
12	Taxes Other than Income Tax	$12,635,649	$509,630	$13,145,279	$0	$13,145,279
13	(Gain)/Loss on Disposition of Property	$156,151	($245,242)	($89,091)	$0	($89,091)
14	<u>TOTAL ELECTRIC OPERATING EXPENSES</u>	$334,959,847	($969,192)	$333,990,655	$14,838,487	$348,829,142
15	**<u>NET OPERATING INCOME</u>**	$73,236,518	($11,053,642)	$62,182,876	$41,785,487	$103,968,363
	<u>ADJUSTMENTS TO OPERATING INCOME</u>					
16	ADD: AFUDC	$14,108,009	($14,108,009)	$0	$0	$0
17	LESS: Charitable Donations	$397,631	($397,631)	$0	$0	$0
18	Interest Expense on Customer Deposits	$31,017	$0	$31,017	$0	$31,017
19	Other Interest Expense/(Income)	$212,619	$0	$212,619	$0	$212,619
20	**<u>ADJUSTED NET ELECTRIC OPERATING INCOME</u>**	$86,703,259	($24,764,019)	$61,939,240	$41,785,487	$103,724,727
21	**<u>RATE BASE (from Line 38 below)</u>**	$1,594,851,513	($264,726,022)	$1,330,125,491	$23,200,860	$1,353,326,351
22	**<u>ROR EARNED ON AVERAGE RATE BASE</u>**	5.4364%		4.6566%		7.6644%

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
FULLY ADJUSTED COST OF SERVICE
SHOWING EFFECTS OF ACCOUNTING ADJUSTMENTS AND REVENUE INCREASE

LINE NO.	**Total of All North Carolina Classes** **Fully Adjusted Cost of Service and Revenue Requirement** **Rate Base** DESCRIPTION	**(1)** **Total NC Jurisdiction Cost of Service**	**(2)** **Ratemaking Adjustments**	**(3)** **Total NC Jurisdiction Fully Adjusted Cost of Service** (Col 1 + Col 2)	**(4)** **Total NC Jurisdiction Base Non-Fuel Additional Revenue Requirement**	**(5)** **Total NC Jurisdiction Fully Adjusted COS After Added Non-Fuel Base Revenues** (Col 3 + Col 4)
	ALLOWANCE FOR WORKING CAPITAL					
23	Materials and Supplies	$50,733,308	$0	$50,733,308	$0	$50,733,308
24	Investor Funds Advanced	$15,791,563	$24,554,504	$40,346,067	$23,200,860	$63,546,927
25	Total Additions	$264,540,117	($212,291,872)	$52,248,245	$0	$52,248,245
26	Total Deductions	($236,039,996)	$200,899,380	($35,140,616)	$0	($35,140,616)
27	TOTAL ALLOWANCE FOR WORKING CAPITAL	$95,024,991	$13,162,012	$108,187,004	$23,200,860	$131,387,864
	NET UTILITY PLANT					
28	Utility Plant in Service	$2,269,147,992	$90,049,544	$2,359,197,536	$0	$2,359,197,536
29	Acquisition Adjustments	$313,057	($313,057)	$0	$0	$0
30	Construction Work in Progress	$360,345,332	($360,345,332)	$0	$0	$0
	LESS:					
31	Accumulated Provision for Depreciation & Amortization	$833,761,769	$38,926,938	$872,688,708	$0	$872,688,708
32	Provision for Acquisition Adjustments	$53,457	($53,457)	($0)	$0	($0)
33	TOTAL NET UTILITY PLANT	$1,795,991,155	($309,482,326)	$1,486,508,829	$0	$1,486,508,829
	RATE BASE DEDUCTIONS					
34	Customer Deposits	$3,135,948	$0	$3,135,948	$0	$3,135,948
35	Accumulated Deferred Income Taxes	$185,445,996	($29,846,253)	$155,599,743	$0	$155,599,743
36	Other Cost Free Capital	$107,582,689	($1,748,038)	$105,834,651	$0	$105,834,651
37	TOTAL RATE BASE DEDUCTIONS	$296,164,633	($31,594,291)	$264,570,342	$0	$264,570,342
38	**TOTAL RATE BASE**	$1,594,851,513	($264,726,022)	$1,330,125,491	$23,200,860	$1,353,326,351

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
SUMMARY OF NORTH CAROLINA JURISDICTION AND CUSTOMER CLASS RATES OF RETURN
PER BOOKS, ANNUALIZED, FULLY ADJUSTED AND FULLY ADJUSTED WITH INCREASE

PER BOOKS CLASS RATE OF RETURNS - FROM ITEM 45a

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$86,703,259	$46,837,624	$16,807,928	$12,406,450	$5,645,147	$4,720,386	$274,001	$11,722
Rate Base	$1,594,851,513	$828,551,058	$349,325,773	$166,024,329	$146,260,248	$65,367,989	$39,098,214	$223,901
ROR	5.4364%	5.6530%	4.8115%	7.4727%	3.8597%	7.2213%	0.7008%	5.2355%
Index		1.04	0.89	1.37	0.71	1.33	0.13	0.96

PER BOOKS CLASS RATE OF RETURNS WITH ANNUALIZED REVENUE - FROM ITEM 45b

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$84,297,043	$49,029,107	$16,079,844	$9,603,836	$6,061,954	$3,254,577	$258,299	$9,425
Rate Base	$1,594,851,513	$828,551,058	$349,325,773	$166,024,329	$146,260,248	$65,367,989	$39,098,214	$223,901
ROR	5.2856%	5.9175%	4.6031%	5.7846%	4.1446%	4.9789%	0.6606%	4.2095%
Index		1.12	0.87	1.09	0.78	0.94	0.12	0.80

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS BEFORE REVENUE INCREASE - FROM ITEM 45c, COL. 3

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$61,939,240	$38,944,088	$10,825,267	$5,916,538	$4,267,116	$2,075,789	($97,311)	$7,752
Rate Base	$1,330,125,491	$700,556,479	$289,958,358	$135,161,075	$113,769,794	$53,670,993	$36,803,653	$205,139
ROR	4.6566%	5.5590%	3.7334%	4.3774%	3.7507%	3.8676%	-0.2644%	3.7787%
Index		1.19	0.80	0.94	0.81	0.83	-0.06	0.81

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS AND AFTER REVENUE INCREASE - FROM ITEM 45c, COLS. 4 & 5

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Revenue Increase	$56,623,974	$29,876,393	$12,786,177	$5,455,529	$4,446,205	$2,013,228	$2,035,411	$11,031
Adjusted NOI	$103,724,727	$60,991,280	$20,260,787	$9,942,429	$7,548,179	$3,561,445	$1,404,714	$15,892
Rate Base	$1,353,326,351	$711,127,830	$294,763,578	$138,238,136	$116,943,089	$54,965,295	$37,081,222	$207,201
ROR	7.6644%	8.5767%	6.8736%	7.1922%	6.4546%	6.4794%	3.7882%	7.6699%
Index		1.12	0.90	0.94	0.84	0.85	0.49	1.00

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	NOI (COS Sch 1, Ln 36)	$46,837,624	$6,712,820	$6,553,261	$12,789,469	$19,342,730	$9,467,235	$9,299,950	$2,014,888
2	NOI Ratio (Based on Ln 1)	100.0000%	14.3321%	13.9914%	27.3060%	41.2974%	20.2129%	19.8557%	4.3019%
3	Rate Base (COS Sch 1, Ln 38)	$828,551,058	$118,748,862	$115,926,283	$226,243,918	$342,170,201	$167,474,079	$164,514,831	$35,643,085
4	Rate Base Ratio (Based on Ln 3)	100.0000%	14.3321%	13.9914%	27.3060%	41.2974%	20.2129%	19.8557%	4.3019%
5	Rate of Return (Ln 1 / Ln 3)	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%	5.65%

PART B

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
6	Change in NOI (Miller Sch 24, Pg 1, Col 2, Ln 20)	$2,191,484							
7	Allocated on NOI Ratio (Ln 2)	$2,191,483	$314,086	$306,620	$598,406	$905,026	$442,962	$435,135	$94,274
8	Annualized NOI (Ln 1 + Ln 7)	$49,029,107	$7,026,906	$6,859,881	$13,387,875	$20,247,756	$9,910,197	$9,735,085	$2,109,162
9	Annualized Rate of Return (Ln 8 / Ln 3)	5.92%	5.92%	5.92%	5.92%	5.92%	5.92%	5.92%	5.92%

PART C

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
10	NOI After All Adjustments and Increase	$60,991,280 *							
11	Allocated on NOI Ratio	$60,991,280	$8,741,338	$8,533,562	$16,654,262	$25,187,824	$12,328,098	$12,110,262	$2,623,758
12	Final Rate Base After All Adjustments	$711,127,830 #							
13	Allocated on Rate Base Ratio	$711,127,830	$101,919,634	$99,497,074	$194,180,365	$293,677,439	$143,739,456	$141,199,596	$30,591,705
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	8.58%	8.58%	8.58%	8.58%	8.58%	8.58%	8.58%	8.58%

*** Total from Miller Sch 25, Page 1, Column 5, Line 20**
 # Total from Miller Sch 25, Page 1, Column 5, Line 21

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	NOI (COS Sch 1, Ln 36)	$16,807,928	$1,079,871	$2,632,101	$5,136,858	$7,768,959	$3,813,993	$3,305,282	$839,822
2	NOI Ratio (Based on Ln 1)	100.0000%	6.4248%	15.6599%	30.5621%	46.2220%	22.6916%	19.6650%	4.9966%
3	Rate Base (COS Sch 1, Ln 38)	$349,325,773	$22,443,388	$54,703,989	$106,761,334	$161,465,323	$79,267,720	$68,694,983	$17,454,359
4	Rate Base Ratio (Based on Ln 3)	100.0000%	6.4248%	15.6599%	30.5621%	46.2220%	22.6916%	19.6650%	4.9966%
5	Rate of Return (Ln 1 / Ln 3)	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%	4.81%

PART B

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
6	Change in NOI (Miller Sch 24, Pg 2, Col 2, Ln 20)	($728,084)							
7	Allocated on NOI Ratio (Ln 2)	($728,084)	($46,778)	($114,017)	($222,518)	($336,535)	($165,214)	($143,178)	($36,379)
8	Annualized NOI (Ln 1 + Ln 7)	$16,079,844	$1,033,093	$2,518,084	$4,914,340	$7,432,424	$3,648,779	$3,162,104	$803,443
9	Annualized Rate of Return (Ln 8 / Ln 3)	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%

PART C

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
10	NOI After All Adjustments and Increase	$20,260,787 *							
11	Allocated on NOI Ratio	$20,260,787	$1,301,710	$3,172,814	$6,192,124	$9,364,939	$4,597,503	$3,984,288	$1,012,347
12	Final Rate Base After All Adjustments	$294,763,578 #							
13	Allocated on Rate Base Ratio	$294,763,578	$18,937,891	$46,159,616	$90,085,975	$136,245,591	$66,886,667	$57,965,316	$14,728,113
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%

*** Total from Miller Sch 25, Page 3, Column 5, Line 20**
 # Total from Miller Sch 25, Page 3, Column 5, Line 21

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
1	NOI (COS Sch 1, Ln 36)	$12,406,450	$38,805	$2,115,861	$4,129,353	$6,245,214	$3,036,521	$2,088,146	$997,765
2	NOI Ratio (Based on Ln 1)	100.0000%	0.3128%	17.0545%	33.2839%	50.3384%	24.4753%	16.8311%	8.0423%
3	Rate Base (COS Sch 1, Ln 38)	$166,024,329	$519,286	$28,314,653	$55,259,410	$83,574,063	$40,635,015	$27,943,778	$13,352,186
4	Rate Base Ratio (Based on Ln 3)	100.0000%	0.3128%	17.0545%	33.2839%	50.3384%	24.4753%	16.8311%	8.0423%
5	Rate of Return (Ln 1 / Ln 3)	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%	7.47%

PART B

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
6	Change in NOI (Miller Sch 24, Pg 3, Col 2, Ln 20)	($2,802,614)							
7	Allocated on NOI Ratio (Ln 2)	($2,802,614)	($8,766)	($477,972)	($932,820)	($1,410,792)	($685,949)	($471,712)	($225,395)
8	Annualized NOI (Ln 1 + Ln 7)	$9,603,836	$30,039	$1,637,889	$3,196,533	$4,834,422	$2,350,572	$1,616,434	$772,370
9	Annualized Rate of Return (Ln 8 / Ln 3)	5.78%	5.78%	5.78%	5.78%	5.78%	5.78%	5.78%	5.78%

PART C

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
10	NOI After All Adjustments and Increase	$9,942,429 *							
11	Allocated on NOI Ratio	$9,942,430	$31,098	$1,695,634	$3,309,230	$5,004,864	$2,433,443	$1,673,424	$799,601
12	Final Rate Base After All Adjustments	$138,238,136 #							
13	Allocated on Rate Base Ratio	$138,238,137	$432,378	$23,575,851	$46,011,075	$69,586,926	$33,834,251	$23,267,047	$11,117,535
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	7.19%	7.19%	7.19%	7.19%	7.19%	7.19%	7.19%	7.19%

*** Total from Miller Sch 25, Page 5, Column 5, Line 20**
 # Total from Miller Sch 25, Page 5, Column 5, Line 21

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
1	NOI (COS Sch 1, Ln 36)	$5,645,146	$2,492	$1,140,913	$2,226,629	$3,367,542	$1,637,150	$0	$637,963
2	NOI Ratio (Based on Ln 1)	100.0000%	0.0441%	20.2105%	39.4432%	59.6538%	29.0010%	0.0000%	11.3011%
3	Rate Base (COS Sch 1, Ln 38)	$146,260,248	$64,556	$29,559,948	$57,689,750	$87,249,698	$42,416,982	$0	$16,529,012
4	Rate Base Ratio (Based on Ln 3)	100.0000%	0.0441%	20.2105%	39.4432%	59.6537%	29.0010%	0.0000%	11.3011%
5	Rate of Return (Ln 1 / Ln 3)	3.86%	3.86%	3.86%	3.86%	3.86%	3.86%	#DIV/0!	3.86%

PART B

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
6	Change in NOI (Miller Sch 24, Pg 4, Col 2, Ln 20)	$416,807							
7	Allocated on NOI Ratio (Ln 2)	$416,807	$184	$84,239	$164,402	$248,641	$120,878	$0	$47,104
8	Annualized NOI (Ln 1 + Ln 7)	$6,061,953	$2,676	$1,225,152	$2,391,031	$3,616,183	$1,758,028	$0	$685,067
9	Annualized Rate of Return (Ln 8 / Ln 3)	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	#DIV/0!	4.14%

PART C

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
10	NOI After All Adjustments and Increase	$7,548,179 *							
11	Allocated on NOI Ratio	$7,548,180	$3,332	$1,525,526	$2,977,246	$4,502,772	$2,189,049	$0	$853,027
12	Final Rate Base After All Adjustments	$116,943,089 #							
13	Allocated on Rate Base Ratio	$116,943,090	$51,616	$23,634,800	$46,126,119	$69,760,919	$33,914,703	$0	$13,215,852
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	6.45%	6.46%	6.45%	6.45%	6.45%	6.45%	#DIV/0!	6.45%

*** Total from Miller Sch 25, Page 7, Column 5, Line 20**
 # Total from Miller Sch 25, Page 7, Column 5, Line 21

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

	Energy	66.1203%							
	Demand	33.8797%							
				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
1	NOI (COS Sch 1, Ln 36)	$4,720,386	$4,583	$772,331	$1,507,296	$2,279,627	$1,108,858	$895,215	$432,102
2	NOI Ratio (Based on Ln 1)	100.0000%	0.0971%	16.3616%	31.9316%	48.2932%	23.4908%	18.9649%	9.1540%
3	Rate Base (COS Sch 1, Ln 38)	$65,367,989	$63,471	$10,695,256	$20,873,064	$31,568,320	$15,355,485	$12,396,955	$5,983,758
4	Rate Base Ratio (Based on Ln 3)	100.0000%	0.0971%	16.3616%	31.9316%	48.2932%	23.4908%	18.9649%	9.1540%
5	Rate of Return (Ln 1 / Ln 3)	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%

PART B

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
6	Change in NOI (Miller Sch 24, Pg 5, Col 2, Ln 20)	($1,465,809)							
7	Allocated on NOI Ratio (Ln 2)	($1,465,810)	($1,423)	($239,830)	($468,057)	($707,887)	($344,331)	($277,989)	($134,180)
8	Annualized NOI (Ln 1 + Ln 7)	$3,254,577	$3,160	$532,501	$1,039,239	$1,571,740	$764,527	$617,226	$297,922
9	Annualized Rate of Return (Ln 8 / Ln 3)	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%

PART C

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	**Customer**	Demand	Energy	Combined			**Energy**
10	NOI After All Adjustments and Increase	$3,561,445 *							
11	Allocated on NOI Ratio	$3,561,444	$3,458	$582,710	$1,137,228	$1,719,937	$836,613	$675,423	$326,013
12	Final Rate Base After All Adjustments	$54,965,295 #							
13	Allocated on Rate Base Ratio	$54,965,294	$53,370	$8,993,208	$17,551,315	$26,544,522	$12,911,806	$10,424,097	$5,031,499
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	6.48%	6.48%	6.48%	6.48%	6.48%	6.48%	6.48%	6.48%

*** Total from Miller Sch 25, Page 9, Column 5, Line 20**
 # Total from Miller Sch 25, Page 9, Column 5, Line 21

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	NOI (COS Sch 1, Ln 36)	$274,001	$212,342	$10,654	$20,793	$31,447	$15,530	$10,587	$4,095
2	NOI Ratio (Based on Ln 1)	100.0000%	77.4969%	3.8883%	7.5887%	11.4770%	5.6677%	3.8637%	1.4946%
3	Rate Base (COS Sch 1, Ln 38)	$39,098,214	$30,299,892	$1,520,291	$2,967,028	$4,487,319	$2,215,988	$1,510,636	$584,379
4	Rate Base Ratio (Based on Ln 3)	100.0000%	77.4969%	3.8884%	7.5887%	11.4770%	5.6677%	3.8637%	1.4946%
5	Rate of Return (Ln 1 / Ln 3)	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%

PART B

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
6	Change in NOI (Miller Sch 24, Pg 6, Col 2, Ln 20)	($15,703)							
7	Allocated on NOI Ratio (Ln 2)	($15,703)	($12,169)	($611)	($1,192)	($1,802)	($890)	($607)	($235)
8	Annualized NOI (Ln 1 + Ln 7)	$258,299	$200,173	$10,043	$19,601	$29,645	$14,640	$9,980	$3,860
9	Annualized Rate of Return (Ln 8 / Ln 3)	0.66%	0.66%	0.66%	0.66%	0.66%	0.66%	0.66%	0.66%

PART C

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
10	NOI After All Adjustments and Increase	$1,404,714 *							
11	Allocated on NOI Ratio	$1,404,715	$1,088,610	$54,620	$106,600	$161,220	$79,616	$54,274	$20,995
12	Final Rate Base After All Adjustments	$37,081,222 #							
13	Allocated on Rate Base Ratio	$37,081,222	$28,736,786	$1,441,862	$2,813,965	$4,255,828	$2,101,670	$1,432,706	$554,232
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%	3.79%

*** Total from Miller Sch 25, Page 11, Column 5, Line 20**
 # Total from Miller Sch 25, Page 11, Column 5, Line 21

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	NOI (COS Sch 1, Ln 36)	$11,722	$6,221	$973	$1,899	$2,872	$1,400	$830	$399
2	NOI Ratio (Based on Ln 1)	100.0000%	53.0665%	8.3004%	16.1967%	24.4971%	11.9455%	7.0838%	3.4070%
3	Rate Base (COS Sch 1, Ln 38)	$223,901	$118,816	$18,583	$36,266	$54,849	$26,746	$15,861	$7,628
4	Rate Base Ratio (Based on Ln 3)	100.0000%	53.0665%	8.2997%	16.1975%	24.4971%	11.9455%	7.0838%	3.4070%
5	Rate of Return (Ln 1 / Ln 3)	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%

PART B

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
6	Change in NOI (Miller Sch 24, Pg 7, Col 2, Ln 20)	($2,297)							
7	Allocated on NOI Ratio (Ln 2)	($2,297)	($1,219)	($191)	($372)	($563)	($274)	($163)	($78)
8	Annualized NOI (Ln 1 + Ln 7)	$9,425	$5,002	$782	$1,527	$2,309	$1,126	$667	$321
9	Annualized Rate of Return (Ln 8 / Ln 3)	4.21%	4.21%	4.21%	4.21%	4.21%	4.21%	4.21%	4.21%

PART C

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
10	NOI After All Adjustments and Increase	$15,892 *							
11	Allocated on NOI Ratio	$15,891	$8,433	$1,319	$2,574	$3,893	$1,898	$1,126	$541
12	Final Rate Base After All Adjustments	$207,201 #							
13	Allocated on Rate Base Ratio	$207,200	$109,954	$17,197	$33,561	$50,758	$24,751	$14,678	$7,059
14	ROR based on Proposed Rev. (Ln 11/ Ln 13)	7.67%	7.67%	7.67%	7.67%	7.67%	7.67%	7.67%	7.66%

*** Total from Miller Sch 25, Page 13, Column 5, Line 20**
 # Total from Miller Sch 25, Page 13, Column 5, Line 21

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$192,922,208	$25,116,060	$16,722,617	$32,636,176	$49,358,793	$17,912,430	$27,608,856	$72,926,069
2	NOI (COS Sch 1, Ln 36)	$46,837,624	$6,712,820	$6,553,261	$12,789,469	$19,342,730	$9,467,235	$9,299,950	$2,014,888
3	NOI Ratio (Based on Ln 1)	100.0000%	14.3321%	13.9914%	27.3060%	41.2974%	20.2129%	19.8557%	4.3019%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($60,621,360)							($60,621,360)
5	Removal of Rider Revenues (on NOI Ratio)	($2,842,691)	($407,418)	($397,734)	($776,224)	($1,173,958)	($574,590)	($564,437)	($122,289)
6	Removal of Facilities Charges (on NOI Ratio)	($96)	($14)	($13)	($26)	($40)	($19)	($19)	($4)
7	Removal of Load Management (assigned to production)	$39		$13	$26	$39			
8	COS Per Books Base Rate Revenue	$129,458,100	$24,708,628	$16,324,883	$31,859,951	$48,184,834	$17,337,821	$27,044,400	$12,182,417

PART B

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
9	Annualized Rate Revenue Adjustment	$2,985,398							
10	Allocated on NOI Ratio (Ln 3)	$2,985,398	$427,871	$417,700	$815,192	$1,232,892	$603,435	$592,772	$128,428
11	Total Revenues (Ln 8 + Ln 10)	$132,443,498	$25,136,499	$16,742,584	$32,675,143	$49,417,726	$17,941,256	$27,637,173	$12,310,844
12	Annualized Billing Units		1,296,996	1,520,481,017	1,520,481,017	1,520,481,017	1,520,481,017	1,520,481,017	1,520,481,017
13	Unit Costs based on Annualized Revenues		$19.38 per month	$0.011011 per kWh	$0.021490 per kWh	$0.032501 per kWh	$0.011800 per kWh	$0.018177 per kWh	$0.008097 per kWh

PART C

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
14	Fully Adjusted Rate Revenue Adjustment	11,085,819							
15	Allocated on NOI Ratio (Ln 3)	11,085,819	1,588,832	1,551,066	$3,027,091	4,578,157	2,240,764	2,201,170	476,896
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$140,543,919	$26,297,460	$17,875,950	$34,887,042	$52,762,991	$19,578,585	$29,245,570	$12,659,313
17	Fully Adjusted Billing Units		1,317,564	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840
18	Unit Costs based on Fully Adjusted Cost of Service		$19.96 per month	$0.011016 per kWh	$0.021499 per kWh	$0.032514 per kWh	$0.012065 per kWh	$0.018022 per kWh	$0.007801 per kWh

PART D

RESIDENTIAL CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
19	Proposed Rate Revenue Adjustment	$30,043,524							
20	Allocated on NOI Ratio (Ln 3)	$30,043,524	$4,305,871	$4,203,523	$8,203,676	$12,407,200	$6,072,663	$5,965,360	$1,292,430
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$170,587,442	$30,603,331	$22,079,473	$43,090,718	$65,170,191	$25,651,248	$35,210,930	$13,951,742
22	Fully Adjusted Billing Units		1,317,564	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840	1,622,763,840
23	Unit Costs based on Proposed Revenue Requirement		$23.23 per month	$0.013606 per kWh	$0.026554 per kWh	$0.040160 per kWh	$0.015807 per kWh	$0.021698 per kWh	$0.008598 per kWh

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$82,094,137	$5,036,976	$7,279,695	$14,207,191	$21,486,886	$7,573,220	$12,471,451	$35,525,603
2	NOI (COS Sch 1, Ln 36)	$16,807,928	$1,079,871	$2,632,101	$5,136,858	$7,768,959	$3,813,993	$3,305,282	$839,822
3	NOI Ratio (Based on Ln 1)	100.0000%	6.4248%	15.6599%	30.5621%	46.2220%	22.6916%	19.6650%	4.9966%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($29,697,669)							($29,697,669)
5	Removal of Rider Revenues (on NOI Ratio)	($1,325,418)	($85,155)	($207,559)	($405,076)	($612,634)	($300,759)	($260,644)	($66,226)
6	Removal of Facilities Charges (on NOI Ratio)	($616,355)	($39,599)	($96,520)	($188,371)	($284,892)	($139,861)	($121,206)	($30,797)
7	Removal of Load Management (assigned to production)	$18		$6	$12	$18			
8	COS Per Books Base Rate Revenue	$50,454,714	$4,912,222	$6,975,622	$13,613,756	$20,589,378	$7,132,600	$12,089,601	$5,730,912

PART B

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
9	Annualized Rate Revenue Adjustment	($981,350)							
10	Allocated on NOI Ratio (Ln 3)	($981,350)	($63,050)	($153,678)	($299,921)	($453,600)	($222,684)	($192,983)	($49,034)
11	Total Revenues (Ln 8 + Ln 10)	$49,473,363	$4,849,172	$6,821,944	$13,313,835	$20,135,779	$6,909,916	$11,896,619	$5,681,878
12	Annualized Billing Units		217,116	745,580,278	745,580,278	745,580,278	745,580,278	745,580,278	745,580,278
13	Unit Costs based on Annualized Revenues		$22.33 per month	$0.009150 per kWh	$0.017857 per kWh	$0.027007 per kWh	$0.009268 per kWh	$0.015956 per kWh	$0.007621 per kWh

PART C

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
14	Fully Adjusted Rate Revenue Adjustment	$16,293							
15	Allocated on NOI Ratio (Ln 3)	$16,293	$1,047	$2,551	$4,979	$7,531	$3,697	$3,204	$814
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$50,471,007	$4,913,268	$6,978,173	$13,618,736	$20,596,909	$7,136,297	$12,092,805	$5,731,726
17	Fully Adjusted Billing Units		221,052	761,872,918	761,872,918	761,872,918	761,872,918	761,872,918	761,872,918
18	Unit Costs based on Fully Adjusted Cost of Service		$22.23 per month	$0.009159 per kWh	$0.017875 per kWh	$0.027035 per kWh	$0.009367 per kWh	$0.015872 per kWh	$0.007523 per kWh

PART D

SGS, COUNTY, & MUNI CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
19	Proposed Rate Revenue Adjustment	$12,973,749							
20	Allocated on NOI Ratio (Ln 3)	$12,973,749	$833,534	$2,031,673	$3,965,052	$5,996,725	$2,943,955	$2,551,290	$648,244
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$63,444,756	$5,746,802	$9,009,847	$17,583,788	$26,593,634	$10,080,253	$14,644,096	$6,379,971
22	Fully Adjusted Billing Units		221,052	761,872,918	761,872,918	761,872,918	761,872,918	761,872,918	761,872,918
23	Unit Costs based on Proposed Revenue Requirement		$26.00 per month	$0.011826 per kWh	$0.023080 per kWh	$0.034906 per kWh	$0.013231 per kWh	$0.019221 per kWh	$0.008374 per kWh

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$53,092,030	$129,942	$4,768,819	$9,306,918	$14,075,737	$5,349,472	$5,910,088	$27,626,791
2	NOI (COS Sch 1, Ln 36)	$12,406,450	$38,805	$2,115,861	$4,129,353	$6,245,214	$3,036,521	$2,088,146	$997,765
3	NOI Ratio (Based on Ln 1)	100.0000%	0.3128%	17.0545%	33.2839%	50.3384%	24.4753%	16.8311%	8.0423%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($22,690,325)							($22,690,325)
5	Removal of Rider Revenues (on NOI Ratio)	($436,077)	($1,364)	($74,371)	($145,143)	($219,514)	($106,731)	($73,397)	($35,071)
6	Removal of Facilities Charges (on NOI Ratio)	($418,566)	($1,309)	($71,384)	($139,315)	($210,700)	($102,445)	($70,449)	($33,662)
7	Removal of Load Management (assigned to production)	$9		$3	$6	$9			
8	COS Per Books Base Rate Revenue	$29,547,072	$127,269	$4,623,067	$9,022,465	$13,645,532	$5,140,295	$5,766,242	$4,867,734

PART B

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
9	Annualized Rate Revenue Adjustment	($3,832,401)							
10	Allocated on NOI Ratio (Ln 3)	($3,832,401)	($11,987)	($653,598)	($1,275,573)	($1,929,171)	($937,993)	($645,037)	($308,213)
11	Total Revenues (Ln 8 + Ln 10)	$25,714,671	$115,282	$3,969,469	$7,746,892	$11,716,361	$4,202,302	$5,121,205	$4,559,520
12	Annualized Billing Units		660	1,248,843	572,194,905	1,248,843	1,349,735	1,349,735	572,194,905
13	Unit Costs based on Annualized Revenues		$174.67 per month	$3.178517 per kW	$0.013539 per kWh	$9.381773 per kW	$3.113427 per kW	$3.794230 per kW	$0.007968 per kWh

PART C

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
14	Fully Adjusted Rate Revenue Adjustment	($4,374,050)							
15	Allocated on NOI Ratio (Ln 3)	($4,374,050)	($13,681)	($745,973)	($1,455,855)	($2,201,829)	($1,070,564)	($736,202)	($351,775)
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$25,173,022	$113,588	$3,877,094	$7,566,610	$11,443,704	$4,069,731	$5,030,040	$4,515,959
17	Fully Adjusted Billing Units		672	1,228,152	562,714,493	1,228,152	1,327,372	1,327,372	562,714,493
18	Unit Costs based on Fully Adjusted Cost of Service		$169.03 per month	$3.156852 per kW	$0.013447 per kWh	$9.317824 per kW	$3.066007 per kW	$3.789472 per kW	$0.008025 per kWh

PART D

LARGE GENERAL SERVICE CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
19	Proposed Rate Revenue Adjustment	$5,414,139							
20	Allocated on NOI Ratio (Ln 3)	$5,414,139	$16,934	$923,356	$1,802,038	$2,725,393	$1,325,129	$911,261	$435,422
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$30,587,161	$130,522	$4,800,449	$9,368,648	$14,169,097	$5,394,860	$5,941,301	$4,951,381
22	Fully Adjusted Billing Units		672	1,228,152	562,714,493	1,228,152	1,327,372	1,327,372	562,714,493
23	Unit Costs based on Proposed Revenue Requirement		$194.23 per month	$3.908677 per kW	$0.016649 per kWh	$11.536925 per kW	$4.064317 per kW	$4.475988 per kW	$0.008799 per kWh

Dominion Energy North Carolina
E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$47,382,199	$12,662	$3,530,999	$6,891,165	$10,422,164	$3,504,680	$0	$33,442,693
2	NOI (COS Sch 1, Ln 36)	$5,645,146	$2,492	$1,140,913	$2,226,629	$3,367,542	$1,637,150	$0	$637,963
3	NOI Ratio (Based on Ln 1)	100.0000%	0.0441%	20.2105%	39.4432%	59.6538%	29.0010%	0.0000%	11.3011%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($28,135,491)							($28,135,491)
5	Removal of Rider Revenues (on NOI Ratio)	$0	$0	$0	$0	$0	$0	$0	$0
6	Removal of Facilities Charges (on NOI Ratio)	($7,479)	($3)	($1,512)	($2,950)	($4,462)	($2,169)	$0	($845)
7	Removal of Load Management (assigned to production)	$10		$3	$7	$10			
8	COS Per Books Base Rate Revenue	$19,239,239	$12,659	$3,529,491	$6,888,221	$10,417,712	$3,502,511	$0	$5,306,357

PART B

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
9	Annualized Rate Revenue Adjustment	$566,062							
10	Allocated on NOI Ratio (Ln 3)	$566,062	$250	$114,404	$223,273	$337,677	$164,164	$0	$63,971
11	Total Revenues (Ln 8 + Ln 10)	$19,805,301	$12,909	$3,643,895	$7,111,495	$10,755,390	$3,666,675	$0	$5,370,328
12	Annualized Billing Units		12	2,037,077	657,936,799	657,936,799	2,037,077	2,037,077	657,936,799
13	Unit Costs based on Annualized Revenues		$1,075.73	$1.788786	$0.010809	$0.016347	$1.799969	$0.000000	$0.008162
			per month	per kW	per kWh	per kWh	per kW	per kW	per kWh

PART C

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
14	Fully Adjusted Rate Revenue Adjustment	$2,783,416							
15	Allocated on NOI Ratio (Ln 3)	$2,783,416	$1,229	$562,543	$1,097,869	$1,660,412	$807,219	$0	$314,556
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$22,022,655	$13,887	$4,092,033	$7,986,091	$12,078,124	$4,309,730	$0	$5,620,913
17	Fully Adjusted Billing Units		12	2,265,143	731,597,816	731,597,816	2,265,143	2,265,143	731,597,816
18	Unit Costs based on Fully Adjusted Cost of Service		$1,157.29	$1.806523	$0.010916	$0.016509	$1.902630	$0.000000	$0.007683
			per month	per kW	per kWh	per kWh	per kW	per kW	per kWh

PART D

SCHEDULE NS CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
19	Proposed Rate Revenue Adjustment	$4,460,689							
20	Allocated on NOI Ratio (Ln 3)	$4,460,689	$1,969	$901,528	$1,759,440	$2,660,968	$1,293,645	$0	$504,107
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$26,483,344	$15,856	$4,993,562	$9,745,531	$14,739,093	$5,603,375	$0	$6,125,020
22	Fully Adjusted Billing Units		12	2,265,143	731,597,816	731,597,816	2,265,143	2,265,143	731,597,816
23	Unit Costs based on Proposed Revenue Requirement		$1,321.36	$2.204524	$0.013321	$0.020146	$2.473740	$0.000000	$0.008372
			per month	per kW	per kWh	per kWh	per kW	per kW	per kWh

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$21,960,947	$15,592	$1,765,212	$3,445,022	$5,210,234	$1,969,119	$2,404,229	$12,361,774
2	NOI (COS Sch 1, Ln 36)	$4,720,386	$4,583	$772,331	$1,507,296	$2,279,627	$1,108,858	$895,215	$432,102
3	NOI Ratio (Based on Ln 1)	100.0000%	0.0971%	16.3616%	31.9316%	48.2932%	23.4908%	18.9649%	9.1540%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($10,169,761)							($10,169,761)
5	Removal of Rider Revenues (on NOI Ratio)	($223)	($0)	($37)	($71)	($108)	($52)	($42)	($20)
6	Removal of Facilities Charges (on NOI Ratio)	($222,433)	($216)	($36,394)	($71,026)	($107,420)	($52,251)	($42,184)	($20,361)
7	Removal of Load Management (assigned to production)	$4		$1	$2	$4			
8	COS Per Books Base Rate Revenue	$11,568,534	$15,376	$1,728,783	$3,373,926	$5,102,709	$1,916,815	$2,362,003	$2,171,631

PART B

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
9	Annualized Rate Revenue Adjustment	($1,984,819)							
10	Allocated on NOI Ratio (Ln 3)	($1,984,819)	($1,927)	($324,748)	($633,785)	($958,533)	($466,251)	($376,418)	($181,689)
11	Total Revenues (Ln 8 + Ln 10)	$9,583,715	$13,448	$1,404,035	$2,740,141	$4,144,176	$1,450,564	$1,985,584	$1,989,942
12	Annualized Billing Units		36	96,466,999	159,019,895	255,486,894	636,467	636,467	255,486,894
13	Unit Costs based on Annualized Revenues		$373.57 per month	$0.014555 per kWh	$0.017231 per kWh	$0.016221 per kWh	$2.279088 per kW	$3.119697 per kW	$0.007789 per kWh

PART C

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
14	Fully Adjusted Rate Revenue Adjustment	($1,743,878)							
15	Allocated on NOI Ratio (Ln 3)	($1,743,878)	($1,693)	($285,327)	($556,849)	($842,175)	($409,652)	($330,724)	($159,634)
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$9,824,655	$13,682	$1,443,457	$2,817,078	$4,260,534	$1,507,163	$2,031,279	$2,011,997
17	Fully Adjusted Billing Units		36	98,893,555	163,019,923	261,913,478	652,477	652,477	261,913,478
18	Unit Costs based on Fully Adjusted Cost of Service		$380.07 per month	$0.014596 per kWh	$0.017281 per kWh	$0.016267 per kWh	$2.309910 per kW	$3.113180 per kW	$0.007682 per kWh

PART D

6VP CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
19	Proposed Rate Revenue Adjustment	$1,990,617							
20	Allocated on NOI Ratio (Ln 3)	$1,990,617	$1,933	$325,697	$635,637	$961,334	$467,613	$377,518	$182,220
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$11,815,273	$15,615	$1,769,154	$3,452,714	$5,221,868	$1,974,776	$2,408,797	$2,194,218
22	Fully Adjusted Billing Units		36	98,893,555	163,019,923	261,913,478	652,477	652,477	261,913,478
23	Unit Costs based on Proposed Revenue Requirement		$433.76 per month	$0.017889 per kWh	$0.021180 per kWh	$0.019937 per kWh	$3.026583 per kW	$3.691772 per kW	$0.008378 per kWh

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$6,091,376	$4,437,354	$118,295	$230,868	$349,163	$88,117	$155,204	$1,061,539
2	NOI (COS Sch 1, Ln 36)	$274,001	$212,342	$10,654	$20,793	$31,447	$15,530	$10,587	$4,095
3	NOI Ratio (Based on Ln 1)	100.0000%	77.4969%	3.8883%	7.5887%	11.4770%	5.6677%	3.8637%	1.4946%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($913,313)							($913,313)
5	Removal of Rider Revenues (on NOI Ratio)	$0	$0	$0	$0	$0	$0	$0	$0
6	Removal of Facilities Charges (on NOI Ratio)	$0	$0	$0	$0	$0	$0	$0	$0
7	Removal of Load Management (assigned to production)	$1		$0	$0	$1			
8	COS Per Books Base Rate Revenue	$5,178,064	$4,437,354	$118,295	$230,868	$349,163	$88,117	$155,204	$148,226

PART B

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
9	Annualized Rate Revenue Adjustment	($21,320)							
10	Allocated on NOI Ratio (Ln 3)	($21,320)	($16,522)	($829)	($1,618)	($2,447)	($1,208)	($824)	($319)
11	Total Revenues (Ln 8 + Ln 10)	$5,156,744	$4,420,832	$117,466	$229,250	$346,716	$86,909	$154,380	$147,907
12	Annualized Billing Units		347,796	21,480,264	21,480,264	21,480,264	21,480,264	21,480,264	21,480,264
13	Unit Costs based on Annualized Revenues		$12.71 per month	$0.005469 per kWh	$0.010673 per kWh	$0.016141 per kWh	$0.004046 per kWh	$0.007187 per kWh	$0.006886 per kWh

PART C

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
14	Fully Adjusted Rate Revenue Adjustment	$72,663							
15	Allocated on NOI Ratio (Ln 3)	$72,663	$56,312	$2,825	$5,514	$8,340	$4,118	$2,807	$1,086
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$5,250,727	$4,493,666	$121,121	$236,382	$357,503	$92,235	$158,011	$149,312
17	Fully Adjusted Billing Units		318,276	19,657,087	19,657,087	19,657,087	19,657,087	19,657,087	19,657,087
18	Unit Costs based on Fully Adjusted Cost of Service		$14.12 per month	$0.006162 per kWh	$0.012025 per kWh	$0.018187 per kWh	$0.004692 per kWh	$0.008038 per kWh	$0.007596 per kWh

PART D

STREET & OUTDOOR LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
19	Proposed Rate Revenue Adjustment	$2,067,260							
20	Allocated on NOI Ratio (Ln 3)	$2,067,260	$1,602,062	$80,381	$156,879	$237,260	$117,167	$79,873	$30,898
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$7,317,988	$6,095,728	$201,502	$393,261	$594,763	$209,402	$237,884	$180,210
22	Fully Adjusted Billing Units		318,276	19,657,087	19,657,087	19,657,087	19,657,087	19,657,087	19,657,087
23	Unit Costs based on Proposed Revenue Requirement		$19.15 per month	$0.010251 per kWh	$0.020006 per kWh	$0.030257 per kWh	$0.010653 per kWh	$0.012102 per kWh	$0.009168 per kWh

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
CUSTOMER, DEMAND, AND ENERGY UNIT COSTS

PART A

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - PER BOOKS

Energy 66.1203%
Demand 33.8797%

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
1	COS Per Books Rate Revenue (COS, Sch 2, Ln 25)	$67,604	$35,266	$2,570	$5,017	$7,587	$2,709	$2,579	$19,463
2	NOI (COS Sch 1, Ln 36)	$11,722	$6,221	$973	$1,899	$2,872	$1,400	$830	$399
3	NOI Ratio (Based on Ln 1)	100.0000%	53.0665%	8.3004%	16.1967%	24.4971%	11.9455%	7.0838%	3.4070%
4	Removal of Fuel Revenues (offset by fuel exp & reg fee)	($16,290)							($16,290)
5	Removal of Rider Revenues (on NOI Ratio)	$0	$0	$0	$0	$0	$0	$0	$0
6	Removal of Facilities Charges (on NOI Ratio)	$0	$0	$0	$0	$0	$0	$0	$0
7	Removal of Load Management (assigned to production)	$0		$0	$0	$0			
8	COS Per Books Base Rate Revenue	$51,314	$35,266	$2,570	$5,017	$7,587	$2,709	$2,579	$3,173

PART B

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ANNUALIZED REVENUE FOR TEST YEAR

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
9	Annualized Rate Revenue Adjustment	($3,109)							
10	Allocated on NOI Ratio (Ln 3)	($3,109)	($1,650)	($258)	($504)	($762)	($371)	($220)	($106)
11	Total Revenues (Ln 8 + Ln 10)	$48,204	$33,616	$2,312	$4,513	$6,825	$2,338	$2,359	$3,067
12	Annualized Billing Units		2,340	465,629	465,629	465,629	465,629	465,629	465,629
13	Unit Costs based on Annualized Revenues		$14.37 per month	$0.004965 per kWh	$0.009692 per kWh	$0.014658 per kWh	$0.005021 per kWh	$0.005065 per kWh	$0.006587 per kWh

PART C

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR ACCOUNTING ADJUSTMENTS AND CUSTOMER GROWTH

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
14	Fully Adjusted Rate Revenue Adjustment	($352)							
15	Allocated on NOI Ratio (Ln 3)	($352)	($187)	($29)	($57)	($86)	($42)	($25)	($12)
16	Total Non-Fuel Base Rate Revenues (Ln 8 + Ln 15)	$50,962	$35,079	$2,541	$4,960	$7,500	$2,667	$2,554	$3,161
17	Fully Adjusted Billing Units		2,352	513,499	513,499	513,499	513,499	513,499	513,499
18	Unit Costs based on Fully Adjusted Cost of Service		$14.91 per month	$0.004948 per kWh	$0.009659 per kWh	$0.014607 per kWh	$0.005194 per kWh	$0.004973 per kWh	$0.006156 per kWh

PART D

TRAFFIC LIGHTING CLASS - CUSTOMER, DEMAND & ENERGY COS - ADJUSTED FOR PROPOSED REVENUE INCREASE

				Demand					
				Production			Transmission	Distribution	
		Total	Customer	Demand	Energy	Combined			Energy
19	Proposed Rate Revenue Adjustment	$11,468							
20	Allocated on NOI Ratio (Ln 3)	$11,468	$6,086	$952	$1,857	$2,809	$1,370	$812	$391
21	Total Non-Fuel Base Rate Revenues (Ln 15 + Ln 20)	$62,430	$41,165	$3,493	$6,817	$10,310	$4,037	$3,366	$3,552
22	Fully Adjusted Billing Units		2,352	513,499	513,499	513,499	513,499	513,499	513,499
23	Unit Costs based on Proposed Revenue Requirement		$17.50 per month	$0.006802 per kWh	$0.013276 per kWh	$0.020077 per kWh	$0.007862 per kWh	$0.006556 per kWh	$0.006917 per kWh

Dominion Energy North Carolina
Estimation of Maximum Revenue Requirement Impact of Distributed Generators
Based on SWPA Allocation Methodology Class Cost of Service Study & Study Modified for Distributed Generators
Docket No. E-22, Sub 694

Distributed Generation Treated as a Distribution Demand Customer at NC Class Level

Ln #	Line	NC Jur Total	Residential	SGS,CO & Muni	LGS	Schedule NS	6VP	St & Outdoor Lighting	Traffic Lighting	Distributed Generation Output
1	Revenues	100,960,657	50,102,002	14,402,683	3,757,117	21,861	1,601,118	7,391,744	27,390	23,656,742
2	O&M Expenses	18,002,279	8,772,004	2,557,117	624,658	3,936	361,078	1,643,081	6,364	4,034,040
3	Depreciation Expense	23,967,043	12,149,348	3,422,779	853,181	7,669	310,059	1,967,003	6,524	5,250,479
4	Income Tax Expense	14,017,251	6,922,894	2,001,863	542,762	2,350	222,906	894,980	3,446	3,426,051
5	Taxes Other Than Income Tax Expense	4,138,090	2,089,519	588,963	155,306	1,059	57,691	279,362	1,017	965,172
6	Total Operating Expense (Lns 2 + 3 + 4 + 5)	60,124,664	29,933,766	8,570,722	2,175,906	15,015	951,734	4,784,427	17,352	13,675,742
7	Net Operating Income (Ln 1 - Ln 6)	40,835,993	20,168,237	5,831,961	1,581,211	6,846	649,384	2,607,317	10,038	9,981,000
8	Plant in Service	839,572,368	425,478,336	119,485,217	31,641,056	191,767	11,773,441	53,540,352	205,433	197,256,767
9	Accumulated Depreciation	306,765,681	162,333,729	43,392,842	11,010,244	102,442	3,300,617	19,521,448	74,458	67,029,901
10	Rate Base (Ln 8 - Ln 9)	532,806,687	263,144,608	76,092,375	20,630,811	89,325	8,472,823	34,018,903	130,975	130,226,866
11	Rate of Return (Ln 7 / Ln 10)	7.664%	7.664%	7.664%	7.664%	7.664%	7.664%	7.664%	7.664%	7.664%

SWPA NC Class Study with No Modifications

Ln #	Line	NC Jur Total	Residential	SGS,CO & Muni	LGS	Schedule NS	6VP	St & Outdoor Lighting	Traffic Lighting
12	Revenues	90,334,145	56,783,314	18,218,438	5,587,488	21,861	2,536,720	7,160,194	26,131
13	O&M Expenses	17,931,805	11,007,450	3,559,264	1,054,640	3,936	632,603	1,667,299	6,614
14	Depreciation Expense	21,387,154	13,530,285	4,222,362	1,238,579	7,669	475,940	1,906,143	6,176
15	Income Tax Expense	11,979,019	7,561,037	2,453,751	775,737	2,350	339,080	843,928	3,135
16	Taxes Other Than Income Tax Expense	4,138,090	2,657,225	834,630	258,602	1,059	101,265	284,238	1,071
17	Total Operating Expense (Lns 13 + 14 + 15 + 16)	55,436,068	34,755,996	11,070,007	3,327,558	15,015	1,548,888	4,701,608	16,996
18	Net Operating Income (Ln 12 - Ln 17)	34,898,077	22,027,317	7,148,431	2,259,930	6,846	987,832	2,458,586	9,134
19	Plant in Service	749,198,101	481,088,608	151,109,169	46,819,642	191,767	18,333,943	51,461,081	193,891
20	Accumulated Depreciation	293,866,233	193,687,688	57,840,178	17,333,256	102,442	5,445,229	19,382,730	74,711
21	Rate Base (Ln 19 - Ln 20)	455,331,868	287,400,920	93,268,992	29,486,386	89,325	12,888,714	32,078,351	119,180
22	Rate of Return (Ln 18 / Ln 21)	7.664%	7.664%	7.664%	7.664%	7.664%	7.664%	7.664%	7.664%

Ln #	Line	NC Jur Total	Residential	SGS,CO & Muni	LGS	Schedule NS	6VP	St & Outdoor Lighting	Traffic Lighting
23	Revenue Requirement Difference (Ln 12 - Ln 1)	13,030,230	6,681,311	3,815,755	1,830,371	-	935,603	(231,550)	(1,260)

DIRECT TESTIMONY
OF
PAUL M. MCLEOD AND CHRISTOPHER J. LEE
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 694

Q. Mr. McLeod, please state your name, business address, position of employment, and area of responsibility within the Company.

A. My name is Paul M. McLeod, and my business address is 120 Tredegar Street, Richmond, Virginia 23219. I am Director, Regulatory Accounting for Virginia Electric and Power Company, which does business in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company"). I am responsible primarily for overseeing the analysis and development of revenue requirement calculations for the Company. A statement of my background and qualifications is attached as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes. I provided direct, supplemental, rebuttal, and stipulation support testimony to the North Carolina Utilities Commission ("Commission") in the Company's 2016 rate case in Docket No. E-22, Sub 521 and in the most recent rate case in Docket No. E-22, Sub 562 ("2019 Rate Case").

Q. Mr. Lee, please state your name, business address, position of employment, and area of responsibility within the Company.

A. My name is Christopher J. Lee, and my business address is 120 Tredegar Street, Richmond, Virginia 23219. I am a Manager, Regulatory Accounting for DENC. I am responsible primarily for overseeing the analysis and development of revenue requirement calculations for the Company. A statement of my background and qualifications is attached as Appendix B.

Q. Have you previously testified before this Commission?

A. No. I have provided testimony to the State Corporation Commission of Virginia in a number of proceedings, most recently in the Company's Virginia Biennial Rate Review in Case No. PUR-2023-00101.

Q. Mr. McLeod, please describe the purpose of your joint testimony in this proceeding.

A. Our testimony supports the Company's proposed increase to North Carolina retail annual non-fuel revenue of approximately $56.6 million. Our testimony includes an overview of the significant issues involved in developing the revenue requirement, an explanation of our exhibits, and a detailed discussion of the Company's regulatory accounting adjustments, as further detailed in the Company's Form E-1, being filed in support of DENC's Application ("Form E-1").

We also discuss the Company's proposal to change how coal combustion residual ("CCR") remediation costs are treated for ratemaking purposes. Specifically, we propose to transition away from deferred recovery and incorporate an ongoing annual level of expenses in the base non-fuel rate cost of service. Additionally, we discuss a request for approval to begin recognizing certain asset retirement obligation ("ARO") costs in a manner consistent with how they are recognized for financial reporting purposes. Finally, we support a request for approval to defer the benefits from nuclear production tax credits ("NPTC") pursuant to the Inflation Reduction Act ("IRA"). The Company has not included any NPTC benefits in its revenue requirement in this case due to uncertainty with respect to the financial impacts. Instead, the Company requests that the Commission allow for deferral of any benefits received to a regulatory liability account to be addressed in a future general rate case proceeding.

Q. How is your joint testimony organized?

A. Our testimony is divided into the following sections:

I. OVERVIEW OF BASE RATE REVENUE REQUIREMENT

II. RATE OF RETURN STATEMENT – ADJUSTED

III. RATE BASE STATEMENT – ADJUSTED

IV. EXPLANATION OF ACCOUNTING ADJUSTMENTS

V. CCR COST RECOVERY PROPOSAL

VI. OTHER ASSET RETIREMENT OBLIGATION COSTS

VII. NPTC DEFERRAL REQUEST

VIII. CONCLUSION

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Company Regulatory Accounting ("RA") Exhibit 1 which supports the revenue requirement and requested revenue increase. Exhibit RA-1 consists of the follow schedules:

Schedule 1 – Rate of Return Statement – Adjusted

Schedule 2 – Rate Base Statement – Adjusted

Schedule 3 – Detail of Accounting Adjustments

Schedule 4 – Lead/Lag Cash Working Capital Calculation – Adjusted

Schedule 5 – Lead/Lag Cash Working Capital Calculation – Additional Revenue Requirement

These schedules were prepared under our supervision and direction and are accurate and complete to the best of our knowledge and belief.

Q. Mr. McLeod, when does the Company intend to implement the base rates proposed in the Application?

A. Due to the significant earnings deficiency under current rates, and in an effort to mitigate regulatory lag, the Company intends to implement proposed rates on a temporary basis subject to refund on November 1, 2024, with new permanent rates requested to become effective on and after February 1, 2025. Our analysis shows the Company earning a return on common equity capital of 5.01% during the fully-adjusted test period presented in our Schedule 1.

Q. Does the revenue requirement presented in this proceeding incorporate an updated base fuel component?

A. Yes. As further described by Company Witness Christopher C. Hewett, the Company is proposing a "placeholder" base fuel rate revenue requirement in the Application. This placeholder base fuel rate is based on the current base fuel rates plus Fuel Rider A approved by Commission in the Company's most recent fuel proceeding, Docket No. E-22, Sub 675 ("2023 Fuel Case"). The Company proposes to supplement the base fuel portion of the revenue requirement after the Company files its annual fuel case in August 2024. This approach to calculating the fuel component of base rates is consistent with the Company's approach in its most recent general rate case, Docket No. E-22, Sub 562 ("2019 Rate Case").

Q. Have you proposed any adjustments to the base non-fuel revenue requirement to reflect changes to the composition of costs recovered through non-fuel rates versus the fuel clause?

A. Yes. The adjustments to purchased energy expenses reflect an updated marketer percentage of 68% supported by Company Witness Jeffrey D. Matzen. The base fuel rate revenue requirement in the supplemental filing will reflect the 68% marketer percentage.

I. OVERVIEW OF BASE RATE REVENUE REQUIREMENT

Q. Mr. McLeod, please define the term "revenue requirement" as discussed in your joint testimony.

A. The revenue requirement represents the annual revenues necessary for DENC to recover its cost of providing utility service to the Company's North Carolina jurisdictional customers. DENC's cost of service includes its operating expenses (including depreciation and taxes) and a fair return on the investment in rate base. The cost of service study, sponsored by Company Witness Robert E. Miller, is used to determine the portion of the system level costs allocable to the North Carolina retail jurisdiction. Our analysis makes necessary regulatory accounting adjustments to the cost of service and demonstrates the revenue required to serve DENC's customers, including the required return on investment to continue to provide this service, as supported by Company Witness Jennifer D. Nelson. To determine the increase in revenue required by the Company, the Company compares the revenue requirement with the operating revenues under existing rates.

Q. Why is the Company seeking a base rate increase in this proceeding?

A. The Company is seeking a rate increase in this proceeding because current base rates are insufficient to fully recover the Company's prudently incurred costs to serve the North Carolina jurisdictional customers and to provide an adequate return on investment to the Company's investors.

Q. What is the test period used to develop the cost of service and proposed revenue increase in this proceeding?

A. The Company's ratemaking test period in this proceeding is the twelve months ended December 31, 2023 ("Test Year"). Pursuant to N.C.G.S. § 62-133(b) and (c), and Rule R1-17 of the Commission's Rules and Regulations, the Company is also proposing ratemaking adjustments to certain revenues, expenses, and investments through June 30, 2024 ("Update Period") based on budgetary information. These adjustments will be updated with actual information in a supplemental filing in August 2024.

Q. What is the amount of the base non-fuel rate revenue increase that DENC is requesting?

A. As presented in Column 5 of Schedule 1 – Rate of Return Statement – Adjusted, the Company's fully-adjusted Test Year reflects an ROE of 5.01%. The Company is requesting a base non-fuel revenue increase of $56.6 million as shown on Column 6 of Schedule 1. This will provide for the recovery of the jurisdictional cost of service after adjustments including an overall rate of return on rate base of 7.66%. The overall rate of return is based on the Company's capital structure and cost of debt supported by Company Witness Richard M. Davis, Jr. and an ROE of 10.60% supported by Company Witness Nelson.

Q. What significant factors are contributing to the Company's need for the revenue increase requested in this proceeding?

A. DENC has made substantial investments in its generation, transmission, and distribution plant in service since the 2019 Rate Case. As discussed by Company Witnesses Edward H. Baine and Jeffrey G. Miscikowski, the Company has continued investing in new generating facilities in order to ensure the continued reliability of the generation fleet moving into the future.

The Company has also made substantial investments in its transmission and distribution systems since the 2019 Rate Case. Company Witness Kevin L. Fields describes the Company's transmission investments and provides details on the Company's efforts to expand and strengthen its power delivery systems in North Carolina. These investments are essential to the Company's ongoing commitment to providing efficient and reliable electric service today and in the future.

In addition to the inclusion of new capital investments in DENC's system, the Company's proposed revenue requirement in this proceeding includes a recovery of expenditures made during the period July 1, 2019 through June 30, 2024 in continued compliance with federal and state environmental regulations associated with managing CCR at several of DENC's generating stations. The CCR regulations and related remediation activities are discussed by Company Witness Miscikowski.

Additionally, purchased power expenses (both capacity and energy) have increased significantly since the 2019 Rate Case. The amount reflected for ratemaking in this case is $9.8 million greater than the amount approved in the 2019 Rate Case.

II. RATE OF RETURN STATEMENT – ADJUSTED

Q. Mr. McLeod, please describe Schedule 1 of Exhibit RA-1.

A. Schedule 1 contains DENC's Rate of Return Statement – Adjusted, which summarizes operating income and rate base for the Test Year, the Company's proposed accounting adjustments, and the revenue requirement necessary for the Company to recover its costs and earn its proposed ROE. Column 1, "Total Company," represents the actual operating income per books (adjusted for the allowance for funds used during construction ("AFUDC"), charitable donations, and interest income and expense other than interest expense on debt), as reported in the Federal Energy Regulatory Commission ("FERC") Form 1, for the legal entity Virginia Electric and Power Company ("VEPCO").[1] The rate base section in Column 1 is a summary of rate base for the total VEPCO system. Schedule 2 of Exhibit RA-1 contains the Rate Base Statement – Adjusted that includes more details on the Company's rate base. I discuss Schedule 2 later in our testimony.

Column 2 represents the difference between the system and North Carolina jurisdictional cost of service. Column 3 contains the North Carolina jurisdictional per books cost of service for the Test Year. These results are supported by the jurisdictional cost of service study sponsored by Company Witness Miller. Column 4 summarizes the accounting adjustments to the jurisdictional per books cost of service in order to pro-form the Test Year to the fully-adjusted Update Period. Schedule 3 of Company Exhibit RA-1 provides an itemized listing of each accounting adjustment in Column 4 of Schedule 1.

[1] See the reconciliation between Column 1, Schedule 1 and the FERC Form 1 in the work papers included in NCUC Form E-1 Item 10.

Q. What does Column 5 of Schedule 1 represent?

A. Column 5 of Schedule 1 contains the North Carolina jurisdictional cost of service after the Company's accounting adjustments. Column 5 is derived by adding the jurisdictional per books cost of service in Column 3 and the accounting adjustments in Column 4. Interest expense on long-term debt is calculated by multiplying the weighted cost of long-term debt, as supported by Company Witness Davis by the fully-adjusted rate base. Interest expense on long-term debt is subtracted from the fully-adjusted jurisdictional cost of service to calculate income available for common equity. The resulting income available for common equity, derived from revenues under current tariff rates less a fully adjusted cost of service, produces an ROE of 5.01%. This return is lower than the Company's proposed cost of common equity of 10.60% as supported by Company Witness Nelson and demonstrates the need for additional base rate revenue in order to reestablish the Company's rates as just and reasonable.

Q. Column 6 of Schedule 1 shows the calculation of the base non-fuel rate revenue deficiency of $56.6 million. What does this represent?

A. This represents the incremental increase in base rates necessary to allow the Company the opportunity to recover the North Carolina jurisdictional operating expenses and earn a return on rate base sufficient to compensate both debt and equity investors.

Q. How was the revenue deficiency in Column 6 of Schedule 1 calculated?

A. The revenue deficiency was calculated in several steps. First, the Company calculates the amount of operating income required for the Company to cover interest expense on debt and to earn the proposed ROE of 10.60%. The operating income requirement is compared to the fully-adjusted operating income on Line 21, Column 5. The difference between the actual and required operating income is divided by the retention factor (*i.e.*, grossed-up for uncollectible expenses, regulatory filing fees, and income taxes), which converts the operating income deficiency to the revenue deficiency of $56.6 million. The impact on cash working capital associated with the requested increase in non-fuel base rates is calculated in Schedule 5.

III. RATE BASE STATEMENT – ADJUSTED

Q. Mr. McLeod, please describe Schedule 2 of Company Exhibit RA-1.

A. Schedule 2 contains DENC's Rate Base Statement – Adjusted, which summarizes the components of rate base and the Company's proposed accounting adjustments to jurisdictional per books rate base. Rate base is comprised of the Allowance for Working Capital, Net Utility Plant, and Other Rate Base Deductions, which are summarized on Schedule 1, Rows 25-28. Column 1, "Total Company," represents the actual rate base per books, as reported in the FERC Form 1, for the legal entity VEPCO.

Column 2 represents the difference between the system and North Carolina jurisdictional rate base. Column 3 contains the North Carolina jurisdictional rate base per books for the Test Year. These results are supported by the jurisdictional Cost of Service Study sponsored by Company Witness Miller. Column 4 summarizes the accounting adjustments to the jurisdictional per books rate base in order to pro-form the Test Year to the fully-adjusted Update Period. Schedule 3 of Company Exhibit RA-1 provides an itemized listing of each accounting adjustment in Column 4 of Schedule 2. Column 5 presents the fully-adjusted North Carolina jurisdictional rate base for calculating the revenue requirement in this proceeding.

IV. EXPLANATION OF ACCOUNTING ADJUSTMENTS

Q. Mr. Lee, what is the purpose of Schedule 3 of Exhibit RA-1?

A. Schedule 3 presents a sequential listing of proposed accounting adjustments to DENC's cost of service using a test year method of estimating the annual revenue needs of the Company's generation, transmission, and distribution services. Some of the adjustments adjust the Test Year from a financial accounting basis to a regulatory accounting basis, while other ratemaking adjustments reflect going-forward costs, revenues, and investments during the Update Period. In the ensuing section, I will discuss each of the regulatory accounting and ratemaking adjustments (collectively referred to as regulatory accounting adjustments) to the cost of service proposed by the Company in this proceeding.

Q. Please list the regulatory accounting adjustments included in Schedule 3.

A. The table below lists the regulatory accounting adjustments to the Test Year cost of service and the page of testimony in which each adjustment is discussed:

Accounting Adjustment No(s). – Description	Page No.
NC-1, NC-4, and NC-6 – Annualize Revenue for Usage, Weather, and Customer Growth as of June, 30, 2024	17
NC-2 and NC-9 – Eliminate DSM and REPS Rider Revenues and Costs	17
NC-3, NC-7, NC-8 and NC-25 – Annualize Fuel Revenues and Expenses at Current Rates	17-18
NC-5 – Normalization of Ancillary Services Revenue	18
NC-10, NC-31, NC-50, NC-58, NC-61, NC-68 and NC-75 – Eliminate the Effects of ASC 410-20 – Asset Retirement Obligations	18-19
NC-11 – Update Purchased Power Capacity	19-20
NC-12 – Update Purchased Power Energy	20
NC-13 – Levelize Nuclear Refueling and Maintenance Outage Expense	20-21
NC-14 – Annualize Salary and Wages – Salaried Payroll	21
NC-15 – Annualize Salary and Wages – Hourly Payroll	21
NC-16 – Annualize Salary and Wages – Services Company	21
NC-17 – Adjust Employee Benefits to June 30, 2024	22
NC-18 – Normalize Annual Incentive Plan Costs	22
NC-19 – Adjust Executive Compensation	22
NC-20 – Normalize Storm Expense	22-23
NC-21 – Eliminate Promotional Advertising Expenses	23
NC-22 – Reclassify Certain Non-Operating Expenses	23
NC-23 – Adjust Certain Operations and Maintenance Expenses for Inflation	23
NC-24 – North Carolina Regulatory Fee	23-24
NC-26 – AMI Opt-out Expenses	24
NC-27 – Amortize Retired Plant Closure Cost Regulatory Asset	24
NC-28 – Amortize Retired Plant Inventory	24-25
NC-29 – Annualize On-Going Coal Combustion Residual Expenditures	25
NC-30 – Eliminate Chesterfield Power Station and Yorktown Power Station Net Operating Expense	25
NC-32, NC-66, NC-74 and NC-76 – Eliminate Acquisition Adjustments	25
NC-33, NC-70 and NC-78 – Annualize Depreciation Expense	26
NC-34, NC-43, NC-63, NC-71 and NC-83 – Eliminate Incremental Costs of Certain Underground Transmission Projects	26
NC-35, NC-44, NC-64, NC-72 and NC-79 – Eliminate AC Cycling Program Costs	27

NC-36 – Amortize Plant Impairment Regulatory Asset	27-28
NC-37 – Amortize CCR Expenditures Regulatory Asset	28-29
NC-38, NC-55 and NC-84 – Adjust Existing Regulatory Assets	29-32
NC-39, NC-60, NC-65, NC-73 and NC-87 – Incorporate Other Certain AROs	32
NC-40 and NC-45 – Interest Synchronization Adjustment	32
NC-41 and NC-46 – Federal and State Income Tax Effect of Adjustments	33
NC-42 and NC-47 – Eliminate the Effects of FIN 48	33-34
NC-48 – Annualize Property Taxes Based on Plant In Service as of June 30, 2024	34
NC-49 – Adjust Payroll Tax for Incremental Payroll	34
NC-51, NC-59 and NC-67 – Eliminate AFUDC Income and CWIP Balance	34-35
NC-52 – Eliminate Charitable Contributions	35
NC-53 – Reflect Interest Expense Based on Proposed Capital Structure, Debt Costs and Adjusted Rate Base	35
NC-54 – CWC Effect of Lead/Lag Study and Accounting Adjustments	35
NC-56 and NC-85 – Adjust Rate Base for New Regulatory Assets	36
NC-57 and NC-81 – Eliminate Nuclear Outage Deferral Balance and Joint Owner Credits	36
NC-62, NC-69 and NC-77 – Update Plant in Service, Accumulated Depreciation, and ADIT to June 30, 2024	36
NC-80 – Eliminate Deferred Fuel ADIT	36
NC-82 – Eliminate Other Nuclear Decommissioning ADIT	37
NC-86 – Update Excess Deferred Income Taxes to June 30, 2024	37

Q. Under what authority does the Company propose to annualize or update operating revenues, expenses, and rate base beyond the end of the Test Year?

A. N.C.G.S. § 62-133(c) requires that rates are fixed based upon a test period that consists of twelve months of historical operating experience prior to the date rates are proposed to become effective. However, this provision allows the Commission to consider relevant, material, and competent evidence demonstrating actual changes in operating revenues, expenses, and rate base within a reasonable time after the test period. Rule R1-17 also provides guidance as discussed below. Therefore, the Company proposes accounting adjustments to annualize or update the cost of service based on budgetary information through June 30, 2024.

Q. Is there also a practical reason for including annualized and updated information beyond the end of the Test Period?

A. Yes. When establishing future rates based on the costs contained in a historical test period, generally the closer the historic test period is updated to the period of time that rates are to be effective, the more likely it is that the cost of service used to establish rates is representative of the utility's actual cost of service while rates are in effect. This also mitigates regulatory lag.

Q. Why did the Company use estimates when N.C.G.S. § 62-133(c) requires that a twelve-month historic test period be used to establish rates?

A. Commission Rule R1-17 governing the Filing of Increased Rates, Application for Authority to Adjust Rates states:

> In the event any affected utility wishes to rely on G.S. 62-133(c) and offers evidence on actual changes based on circumstances and events leading up to the time the hearing is closed, such utility shall file with any general rate application detailed estimates of any such data and such estimates should be expressly identified and presented in the context of the filed test year data and, if possible, in the context of a 12 month period of time ending the last day of the month nearest and following 120 days from the date of the application.

Rule R1-17 therefore allows the Company to file its application for a base rate increase supported by estimates. N.C.G.S. § 62-133(c) does require that the final cost of service used to establish rates include actual historical data. As such, the Company will file supplemental testimony in August 2024 that updates the estimates with actual June 30, 2024 results. This approach is also consistent with the Company's approach in prior rate cases.

Q. Why did the Company select June 30, 2024 as the update point for the estimated costs included in the cost of service?

A. Since Rule R1-17 allows estimates of costs up to 120 days after the date of the application, the Company proposes to utilize the latest quarterly reporting period that falls within this 120-day period. The Company has included the necessary normalizing and annualizing adjustments required to appropriately update the revenues, costs, and investments to amounts either outstanding at June 30, 2024, or amounts based on the level included in the twelve months ending June 30, 2024.

Q. Mr. Lee, please proceed with your explanation of each adjustment in Schedule 3.

A. I will discuss each of the accounting adjustments in the order that it appears on Schedule 3. In cases where several adjustments relate to a single subject, I will discuss each of the related adjustments within that one section, in which case, those adjustments will be discussed out of numeric order. The detailed work papers supporting these adjustments are included in Item 10 of Form E-l.

Adjustment NC-1, NC-4, and NC-6 – Annualize Revenue for Usage, Weather, and Customer Growth as of June, 30, 2024

The Company annualized base non-fuel tariff revenues based on projected customer levels and weather normalized usage as of June 30, 2024. Company Witness Givens discusses this adjustment in his testimony.

Adjustments NC-2 and NC-9 – Eliminate Demand-Side Management ("DSM") and Renewable Energy Portfolio Standard ("REPS") Rider Revenues and Costs

These adjustments eliminate revenues and expenses associated with the Company's DSM and REPS programs that are recovered through North Carolina jurisdictional riders. This ensures that costs recovered under these mechanisms have no effect on the North Carolina jurisdictional base rate cost of service.

Adjustments NC-3, NC-7, NC-8 and NC-25 – Annualize Fuel Revenues and Expenses at Current Rates

These adjustments eliminate the net effect of fuel costs and recoveries from the cost of service per books. The cost of service per books includes the fuel clause revenue recorded during the Test Year, including deferred fuel revenue entries related to the Company's Experience Modification Factor. This adjustment annualizes fuel clause revenue by applying the current base fuel rate plus Rider A to the annualized and normalized customer usage at June 30, 2024. In conjunction with this adjustment to fuel clause revenue, an adjustment is made to fuel clause expense to make fuel clause expense equal to fuel clause revenue, net of the regulatory fee.

Adjustment NC-5 – Adjust Ancillary Service Margins

The going-level of ancillary services revenue is based on the projected net revenues received by the Company from the PJM Interconnection, L.L.C. ("PJM") markets during calendar year 2024. All ancillary services revenue is presented net of amounts related to jointly-owned facilities providing PJM ancillary services and ancillary services charges recorded when the Company is required to purchase ancillary services instead of providing its own. The projection will be updated with actual net revenues in the Company's supplemental filing in August 2024.

Adjustments NC-10, NC-31, NC-50, NC-58, NC-61, NC-68 and NC-75 – Eliminate the Effects of ASC 410-20 – Asset Retirement Obligations

Statement of Financial Accounting Standard ("SFAS") No. 143 (now codified as Accounting Standard Codification ("ASC") 410-20) was implemented in 2003 for financial reporting purposes to recognize liabilities for the expected cost of retiring tangible long-lived assets for which a legal obligation exists. For financial reporting purposes, these AROs are recognized at fair value and are capitalized as part of the cost of the related long-lived assets. As discussed in more detail by Mr. McLeod in Section V of this testimony, the Company eliminates all the effects of ARO accounting pursuant to ASC 410-20 from the North Carolina jurisdictional cost of service. The Commission has historically provided for recovery through base rates of nuclear decommissioning costs, a significant ARO for the Company, over the service lives of the facilities and placed these collections in external trusts. The Company is proposing separate adjustments to address CCR ARO costs, as well as other non-nuclear AROs. I discuss these adjustments later in my testimony.

Adjustment NC-11 – Update Purchased Power Capacity

The change in capacity costs for the twelve months ending June 30, 2024, reflects the ongoing level of costs of capacity purchased from the PJM capacity market, power purchase agreements ("PPA"), and other third parties.

The estimated costs of capacity purchases from PJM are based on the Company's total load requirements as measured by PJM less any Company controlled sources of load available for use in the PJM market. For this capacity purchased through the PJM capacity market, the Company applied a normalized capacity rate to its projected load position for the PJM delivery year beginning June 1, 2024. By using the Company's net load position over the PJM delivery year, the purchase of capacity from the PJM market incorporates newer generation resources. The normalized PJM purchased capacity rate was based on the average of the 10 years from June 1, 2014 through May 31, 2023. This period of time represents both a historical range and three forward delivery years.

The PPA capacity purchases are based on an estimate for the twelve months ended June 30, 2024 for those Independent Power Producer contracts that extend beyond the Update Period. This adjustment excludes from base non-fuel cost of service capacity costs associated with qualifying facilities under the Public Utility Regulatory Policies Act of 1978 that are not subject to economic dispatch or curtailment. The Company will reflect these costs as recoverable through the fuel clause in its 2024 fuel clause filing.

Adjustment NC-12 – Update Purchased Power Energy

The purpose of this adjustment is to adjust the Test Year non-fuel purchased power energy expenses recovered through base non-fuel rates based on projected activity during the twelve months ending June 30, 2024. As discussed by Company Witness Matzen, the Company proposes to use an updated marketer percentage of 68% for purchased energy costs from PJM for recovery through the base fuel component. This adjustment eliminates 68% of the Company's energy costs purchased from PJM from the purchased power energy estimate and recognizes the impact of moving all PPA energy purchases to base fuel rates.

Adjustment NC-13 – Levelize Nuclear Refueling and Maintenance Outage Expense

DENC operates four nuclear units: two units at the Surry Power Station and two units at the North Anna Power Station. The Company utilizes a "3/3/2" planning practice for scheduling nuclear outages. This means the Company performs three outages in two successive years, then two outages every third year. Refueling outages occur on a fixed timeline and are therefore scheduled to occur every eighteen months for each nuclear unit. The Company incurs substantial outage costs during the refueling outages and the costs fluctuate from year to year. This adjustment calculates a levelized amount of costs based on the costs for the most recent outage at each of the four nuclear units.

Adjustment NC-14 – Annualize Salary and Wages as of June 30, 2024 – Salaried Payroll

Salaries and wages for salaried DENC employees are annualized based on the Test Year ending headcount and actual average rate during the month of December 2023 including the budgeted merit increase of 3.25% in March 2024.

Adjustment NC-15 – Annualize Salary and Wages as of June 30, 2024 – Hourly Payroll

Salaries and wages for hourly DENC employees are annualized based on the Test Year ending headcount and actual average rate during the month of December 2023 including the actual merit increase of 2.75% in March 2024.

Adjustment NC-16 – Annualize Salary and Wages as of June 30, 2024 – Services Company

Salaries and wages for Dominion Energy Services, Inc. employees are annualized based on the Test Year ending headcount and actual average rate during the month of December 2023 including the budgeted merit increase of 3.25% in March 2024.

Adjustment NC-17 – Adjust Employee Benefits Costs to June 30, 2024

Employee benefit costs are adjusted based on the six months of actual benefits costs for July through December 2023 and six months of projected benefits costs for January through June 2024. This adjustment includes the following employee benefits costs: pension; other post-employment benefits; medical, dental, and vision insurance; life insurance; employee savings plan; long-term disability; education benefits; and other miscellaneous benefits.

Adjustment NC-18 – Normalize Annual Incentive Plan Costs

The Annual Incentive Plan represents at-risk compensation paid out to Company employees only upon meeting certain operational and financial goals during the plan year. This adjustment provides for 100% of the plan target based on employees meeting all operational and financial goals during the year.

Adjustment NC-19 – Adjust Executive Compensation

This adjustment removes 50% of the compensation of the three executives with the highest level of compensation allocated to DENC during the Test Year.

Adjustment NC-20 – Normalize Major Storm Restoration Expense

Given the unpredictable nature of storm activity, which can cause a material level of expense in a short period of time, it is appropriate to include a normalized level of storm expense in the cost of service for ratemaking purposes. The Company relied upon an historical average of storm activity and cost during the nine years of 2015-2023 in determining a normalized level in order to capture a broad range of its experience responding to a variety of storm types, durations and severity.

Adjustment NC-21 – Eliminate Promotional Advertising Expenses

This adjustment eliminates all promotional advertising expenses from the Test Year.

NC-22 – Reclassify Certain Non-Operating Expenses

This adjustment reclassifies certain expenses associated with ongoing maintenance of a beneficial use site that are considered non-operating.

Adjustment NC-23 – Adjust Certain Operations and Maintenance Expenses for Inflation

The Company adjusts O&M expenses in the cost of service not adjusted elsewhere. The unadjusted items are increased by an inflation factor measured as the difference of the Producer Price Index Finished Goods less Food and Energy between the midpoint of the Test Year and the end of the Update Period.

Adjustment NC-24 – North Carolina Regulatory Fee

The Company pays the North Carolina regulatory fee to the Commission based on a percentage of North Carolina jurisdictional revenues. Effective July 1, 2023, the regulatory fee percentage rate increased to 0.1475%. This adjustment recalculates the Test Year regulatory fee expense based on this new, higher rate. The Retention Factor used to calculate the incremental revenue requirement also reflects the latest regulatory fee percentage rate.

Adjustment NC-26 – AMI Opt-out Expenses

This adjustment reflects the projected costs for Residential customers expected to opt-out of the Company's AMI program in 2024, as discussed in the pre-filed direct testimony of Company Witness Robert Miller.

Adjustment NC-27 – Amortize Retired Plant Closure Cost Regulatory Asset

Between 2014 and 2023 the Company has retired multiple units at several of its fossil fuel-powered generation facilities. The Company began incurring decommissioning costs and other costs in connection with these closures in 2013 and continues to incur these types of costs through the Update Period in this case. This adjustment includes amortization of costs incurred from July 1, 2019 through June 30, 2024, to be recovered over a three-year period. This methodology is consistent with the treatment of similar costs in the Company's prior rate cases.

Adjustment NC-28 – Amortize Retired Plant Inventory

The Company ceased operation of Possum Point Power Station ("Possum Point") Unit 5 in December 2020, Chesterfield Power Station ("Chesterfield) Units 5 and 6 and Yorktown Power Station ("Yorktown") Unit 3 in May 2023. Materials & supplies inventory for these units were written-off for financial reporting purposes between January 1, 2020 and December 31, 2023. This adjustment amortizes the inventory write-offs over a three-year period. This methodology is consistent with the treatment of similar costs in the Company's prior rate cases.

Adjustment NC-29 – Annualize On-Going Coal Combustion Residual Expenditures

In this proceeding, the Company is proposing to recover an on-going level of CCR compliance costs for ratemaking purposes, as further discussed by Company Witness McLeod in Section V of this testimony. This adjustment annualizes CCR costs based on projected costs during the first six months of 2024 (*i.e.,* from January 1, 2024 through June 30, 2024).

Adjustment NC-30 – Eliminate Chesterfield Power Station and Yorktown Power Station Net Operating Expense

This adjustment eliminates all net operating expenses attributable to Chesterfield Units 5 and 6 and Yorktown Unit 3 during the Test Year in order to remove the impact of these retired units' operating expenses from the revenue requirement going forward. The amortization of deferred impairment costs is discussed later in my testimony.

Adjustments NC-32, NC-66, NC-74 and NC-76 – Eliminate Acquisition Adjustments

These adjustments eliminate acquisition amortization and net balances from rate base.

Adjustments NC-33, NC-70 and NC-78 – Annualize Depreciation Expense

Adjustment NC-33 annualizes depreciation expense based on projected plant in service as of June 30, 2024 and the composite depreciation rate from the Company’s most recent depreciation study. This corresponds with the Company’s fully-adjusted plant in service. Adjustments NC-70 and NC-78 reflect the impact of annualizing depreciation expense on accumulated depreciation and ADIT, respectively. Depreciation rates for certain generating stations have been changed since the study was completed. The revenue requirement impact of any changes in depreciation rates will be reflected in the Company's supplemental filing.

Adjustments NC-34, NC-43, NC-63, NC-71 and NC 83 – Eliminate Incremental Costs of Certain Underground Transmission Projects

In the 2012 Rate Case, the Commission excluded from cost of service the incremental costs associated with undergrounding certain transmission projects versus constructing the systems overhead.[2] The specific projects are the Pleasant View-Hamilton, Garrisonville, and Dupont-Fabros projects. These adjustments eliminate the incremental depreciation expense, excess deferred income taxes, plant in service, accumulated depreciation, and ADIT associated with undergrounding these projects.

[2] Order Granting General Rate Increase at 9, Docket No. E-22, Sub 479 (Dec. 21, 2012) (“2012 Rate Order”).

Adjustments NC-35, NC-44, NC-64, NC-72 and NC-79 – Eliminate AC Cycling Program Costs

These adjustments are necessary to eliminate costs associated with the Company's AC Cycling Program that are recovered through the DSM Rider. This ensures that the program has no effect on the North Carolina jurisdictional base rate cost of service.

Adjustment NC-36 – Amortize Plant Impairment Regulatory Asset

As previously discussed in this testimony, Possum Point Unit 5 ceased operations in 2020 and Chesterfield Units 5 and 6 and Yorktown Unit 3 ceased operations in 2023. The Company proposes to recover the Possum Point Unit 5, Chesterfield Units 5 and 6, and Yorktown Unit 3 impairment losses on a levelized basis over a 10-year amortization period. In order to calculate the impairment losses for ratemaking purposes in this case, the Company determined the net book value as of December 31, 2020 (Possum Point unit) and May 31, 2023 (Chesterfield and Yorktown units) assuming the facilities had not been impaired early for financial reporting purposes. This balance was derived starting with the balance as of the date the units ceased operations, adjusted for additional depreciation expense during the interim years. This methodology is consistent with the Commission's treatment of similar production plant early retirement costs in the Company's prior rate cases.

The Company is proposing to deduct the excess amortization associated with various expired generation-related regulatory assets from the requested deferred impairment loss. This amount represents excess amortization from the expiration date of these generation-related regulatory assets through the date interim rates are expected to be implemented (November 1, 2024).[3] These expired generation-related regulatory assets are described in more detail later in my testimony (under the "Adjust Existing Regulatory Assets" heading).

Adjustment NC-37 – Amortize CCR Expenditures Regulatory Asset

As discussed by Company Witness Miscikowski, the Environmental Protection Agency's 2015 regulations ("Federal CCR Rule") requires an owner/operator of an existing coal combustion residual CCR surface impoundment unit to close the unit under certain circumstances and in certain ways. In 2019, Virginia enacted legislation that specifies exceptions to the closure options granted under the Federal CCR Rule. Witness Miscikowski provides additional detail on DENC's ongoing efforts to close such ash ponds, as required under the CCR Rule.

In this proceeding, the Company is proposing to recover its CCR ARO-related cash expenditures, incurred from July 1, 2019 through June 30, 2024 ("2024 CCR ARO deferrals"), over a five-year amortization period. The Company is also proposing to deduct the excess amortization associated with expired CCR ARO-related regulatory assets ("2016 CCR ARO deferrals") from the

[3] In the 2019 Rate Order, the Commission required the Company to "continue to record all revenue received" for expired regulatory assets "until the Company's next general rate case" (Finding of Fact 63). The Company has recorded all such "excess" amortization to a regulatory liability account and is being addressed through various adjustments discussed herein.

requested 2024 CCR ARO deferrals. This amount represents excess amortization from the expiration date of the 2016 CCR ARO deferrals regulatory asset through the date interim rates are expected to be implemented (November 1, 2024). The 2016 CCR ARO deferral regulatory asset was approved in the Company's 2016 Rate Case.

From the period July 1, 2019 through the end of the Test Year, the Company's CCR-related cash expenditures totaled $516.6 million, and the Company anticipates spending an additional $105.0 million during the Update Period, resulting in total projected cash expenditures of $621.6 million. The North Carolina jurisdictional portion of these expenditures is $26.7 million. This accounting adjustment also reflects the cost of capital associated with these expenditures incurred during the July 1, 2019 through October 31, 2024 (the date prior to the effective date of interim rates requested in this proceeding) spending period totaling $4.6 million based on the weighted average cost of capital approved in the 2019 Rate Case.

Adjustment NC-38, NC-55 and NC-84 – Adjust Existing Regulatory Assets

These adjustments are made to reflect the appropriate level of amortization and rate base balances associated with the following existing regulatory assets:

<u>CCR Expenditures Regulatory Asset</u> – Costs associated with CCR expenditures being proposed for recovery in this proceeding are incorporated

into the cost of service through separate accounting adjustments as discussed previously in my testimony. As such, the amortization and balances of the proposed regulatory assets net of ADIT per books are eliminated. The regulatory assets representing the CCR ARO-related cash expenditures incurred from July 1, 2016 through June 30, 2019 ("2019 CCR ARO") were approved for recovery over a 10-year amortization period and this adjustment reflects the appropriate level of amortization consistent with the 2019 Rate Order.[4] These regulatory assets were approved for recovery without a return, therefore the associated per books rate base balances net of ADIT are eliminated in this adjustment.

Yorktown Units 1 and 2 and Cold Reserve Plant Impairments – Yorktown Units 1 and 2 were impaired for financial reporting purposes in 2019. In addition, ten older, less efficient generating units that had been in a "cold reserve" state since 2018 were also impaired for financial reporting purposes in 2019 ("Cold Reserve Plants"). The Commission allowed for recovery of the Yorktown Units 1 and 2 and the Cold Reserve Plants impairments on a levelized basis over a ten-year period.[5] The regulatory assets established on the Company's books only include the principal amount (nominal impairment). It is necessary to adjust the amortization in the cost of service to a revenue requirement level that includes both the principal and return

[4] Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Increase, Docket No. E-22, Sub 562 (Feb. 24, 2020) ("2019 Rate Order") (Finding of Fact 53).
[5] 2019 Rate Order at 58.

component. The regulatory asset balances net of ADIT are eliminated from rate base since the return on these regulatory assets is provided through the levelized amortization.

Possum Point Unit 5 Impairment Deferral – Possum Point Unit 5 was impaired for financial reporting purposes in 2019. The Commission allowed for the impairment losses to be deferred for financial reporting purposes in the 2019 Rate Case.[6] However, the Commission deferred contemplation of the retirement of Possum Point Unit 5 until the facility was physically retired from service.[7] Costs associated with the Possum Point Unit 5 impaired assets are incorporated into the cost of service through the "Amortize Retired Plant Impairment Regulatory Asset" accounting adjustment previously discussed in my testimony. As such, the per books amortization and rate base balances of these regulatory assets net of ADIT are eliminated in this adjustment.

Chesapeake Energy Center Impairment and Gordonsville NUG Buyout Deferral – These regulatory assets will be fully-amortized before the date permanent rates in this proceeding become effective (February 1, 2025). This adjustment eliminates the amortization and rate base balances associated with these regulatory assets.

Other Expired Regulatory Deferrals – The following regulatory assets were fully-amortized prior to the beginning of the Test Year:

---

[6] *Id.*
[7] *Id.*

- 2016 CCR ARO deferrals;
- Birchwood NUG termination;
- North Branch Power Station impairment;
- Mount Storm Fuel Flexibility Project impairment;
- Greensville Power Station deferral;
- Chesapeake Energy Center Closure Costs; and
- Retired Plant Materials and Supplies Inventory.

This adjustment eliminates the amortization and rate base associated with these expired regulatory assets.

Adjustments NC-39, NC-60, NC-65, NC-73 and NC-87 – Incorporate Other Certain AROs

These adjustments are made to reflect the appropriate level of expenses and rate base balances associated with certain AROs not otherwise recovered by the Company through existing mechanisms. The Company's proposal to recover these other certain ARO-related costs is discussed in more detail by Company Witness McLeod in Section VI of this testimony.

Adjustments NC-40 and NC-45 – Interest Synchronization Adjustment

These adjustments reflect the federal and state income tax impacts of adjusting interest expense based on fully-adjusted rate base.

Adjustments NC-41 and NC-46 – Federal and State Income Tax Effect of Adjustments

These adjustments reflect the change in federal income tax expense produced by aggregating all of the accounting adjustments to revenues and expenses and determining the relevant federal and state income tax expense on the adjusted level of pre-tax book income.

Adjustments NC-42 and NC-47 – Eliminate the Effect of FASB Interpretation No. 48 ("FIN 48")

FIN 48, *Accounting for Uncertainty in Income Taxes,* adopted by the Company effective January 1, 2007, established standards for recognition and measurement for tax positions taken on tax returns for which there is uncertainty concerning the application of tax law and, therefore, uncertainty about whether the tax position will ultimately be sustained. Accordingly, the Company is required by FIN 48 to record income tax expense and related current and deferred taxes to reflect only those tax return positions, or portions thereof, which will more likely than not be sustained. Those tax positions that are not recognized in the financial statements represent contingencies that may be settled in a future audit, appeals process, or litigation, or by expiration of the applicable statute of limitations. However, for regulatory accounting purposes, since the Company has actually received the cash benefit from the tax return position taken, current and deferred income tax expense included in Test Year cost of service and related ADIT have been adjusted to reflect the tax positions taken in tax returns filed.

In the event the Company is not successful in sustaining such tax return positions and pays additional taxes, the Company will make an adjustment for regulatory accounting purposes at that time to reflect the related increase in current taxes and decrease in deferred tax liabilities. Likewise, if, subsequent to filing a tax return, the Company presents a claim for additional deductions and ultimately receives a refund or pays less tax, the Company will make an adjustment for regulatory accounting purposes at that time to reflect the related decrease in current taxes and increase in deferred tax liabilities.

Adjustment NC-48 – Annualize Property Taxes Based on Plant in Service as of June 30, 2024

Property taxes are annualized based on the projected level of plant in service as of June 30, 2024. Property taxes are calculated by applying the ratio of 2023 property tax expense and the December 31, 2023 plant in service balance. This ratio is then applied to the projected level of plant in service as of June 30, 2024.

Adjustment NC-49 – Adjust Payroll Tax for Incremental Payroll

This adjustment incorporates incremental payroll tax expense associated with the ratemaking adjustments to salaries and wage expenses.

Adjustment NC-51 – Eliminate AFUDC Income;

Adjustment NC-59 – Eliminate CWIP Accounts Payable and Accrued Payroll; and

Adjustment NC-67 – Eliminate CWIP Balance

AFUDC, CWIP, and related working capital items are eliminated so that these items have no effect on the fully-adjusted ratemaking analysis.

Adjustment NC-52 – Eliminate Charitable Contributions

This adjustment eliminates charitable contributions from the cost of service consistent with the Company's practices in previous rate cases.

Adjustment NC-53 – Reflect Interest Expense Based on Proposed Capital Structure, Debt Costs, and Adjusted Rate Base

This adjustment reflects the change necessary to present interest that would arise based on the capital structure, debt costs and rate base proposed in this proceeding.

Adjustment NC-54 – CWC Effect of Lead/Lag Study and Accounting Adjustments

This adjustment to cash working capital ("CWC") is based on a lead/lag study prepared based on calendar year 2021 data. The CWC requirement included in the cost of service per books is adjusted based on the adjusted CWC requirement as determined for regulatory purposes. The revenue lag and uncollectible expense lead used has been updated to reflect continuing changes to customer behavior since the onset of the COVID-19 pandemic and the return to a more traditional payment pattern. The calculation of the adjusted CWC requirement is included in Schedule 4 of Exhibit RA-1. See Form E-1 Item 14 for workpapers supporting the Company's 2021 lead/lag study.

Adjustment NC-56 and NC-85 – Adjust Rate Base for New Regulatory Assets

This adjustment incorporates in rate base the balances of new North Carolina jurisdictional regulatory assets being requested in this proceeding. The Company deducted one year of amortization from the balance of each new regulatory asset, and the remaining balance is included net of ADIT.

Adjustment NC-57 and NC-81 – Eliminate Nuclear Outage Deferral Balance and Joint Owner Receivables

This adjustment eliminates the nuclear outage deferral balance and associated ADIT from rate base as well as joint owner receivables from the allowance for working capital.

Adjustments NC-62, NC-69, and NC-77 – Update Plant in Service, Accumulated Depreciation, and ADIT to June 30, 2024

These adjustments update plant in service, accumulated depreciation, and plant-related ADIT to the end of the Update Period based on budgetary information.

Adjustment NC-80 – Eliminate Deferred Fuel ADIT

This adjustment eliminates ADIT associated with the deferred fuel balance because the associated deferred fuel balance is not included as a component of rate base.

Adjustment NC-82 – Eliminate Other Nuclear Decommissioning ADIT

This adjustment eliminates ADIT associated with earnings on the decommissioning trust funds of the nuclear power stations because the Company does not have use of these funds due to the regulations under which the decommissioning trusts operate.

Adjustment NC-86 – Update Excess Deferred Income Taxes to June 30, 2024

This adjustment updates certain categories of excess deferred income taxes to the end of the Update Period based on budgetary information.

V. CCR COST RECOVERY PROPOSAL

Q. Mr. McLeod, please describe the Company's proposed cost recovery method for recovering CCR ARO costs in this case.

A. The Company has proposed two adjustments in this case to address ARO costs in connection with compliance with federal and state environmental requirements related to closing coal ash ponds. The first adjustment uses a similar methodology as approved in the Company's two most recent rate cases of amortizing CCR expenditures incurred since the Company's last rate case (*i.e.*, CCR expenditures incurred from July 1, 2019 through June 30, 2024) over a multi-year period. The second adjustment, which is new for this proceeding, incorporates an ongoing annual level of expenses the Company will incur in the future. As discussed in more detail by Company Witness Miscikowski, the Company has several long-term projects to comply with federal and state environmental regulations. In my view, given these facts and the nature of the costs, it is preferrable to treat these costs as operating expenses for ratemaking purposes.

Q. Please elaborate.

A. In the absence of ARO accounting, it's possible that these expenses would be charged to O&M expense for financial reporting purposes. Further, as described by Company Witness Miscikowski, the cash flows over the next several years are projected to be steady. These facts support a more traditional cost recovery methodology (*i.e.,* treating as an operating expense) rather than deferring costs in between rate cases and amortizing them over an extended period of time. The traditional recovery method is more predictable, allows for timely recovery of costs, and avoids the "pancaking" of costs (*i.e.,* overlapping vintages of CCR regulatory asset amortizations across multiple, future rate cases).

Q. Why is the Company proposing two separate adjustments in this proceeding?

A. If the Commission approves the Company's proposal to begin treating these costs as operating expenses, then this case represents a transition away from the previously approved methodology to the new methodology. The Company will capture costs incurred since the last case to be recovered through regulatory asset amortization. However, beginning November 1, 2024, the implementation date of interim rates, the Company will begin recovering the costs as operating expenses and will no longer need to defer cash expenditures between rate cases. There will only remain five months of deferred costs to be addressed in the Company's next rate case (*i.e.,* expenditures from July 1, 2024 through October 31, 2024), which likely will be a lower amount as compared to CCR regulatory assets proposed in this case and approved in prior cases as it is a much shorter time period.

Q. Please quantify the amount of ongoing CCR costs the Company is proposing to include for ratemaking purposes in this proceeding.

A. The Company calculates an annualized level based on projected costs during the first six months of 2024 expected to be incurred (i.e., from January 1, 2024 through June 30, 2024). Annualized on-going CCR compliance costs totaled $209.9 million at the system level and $9.0 million at the North Carolina jurisdictional level.

VI. OTHER ASSET RETIREMENT OBLIGATION COSTS

Q. Mr. McLeod, please briefly describe "asset retirement obligations" including the financial reporting requirements.

A. Asset retirement obligations (previously defined as "ARO") represent obligations that result from laws, statutes, contracts, and regulations related to the eventual retirement of certain of the Company's long-lived assets. The Company recognizes liabilities for the expected cost of retiring tangible long-lived assets for which a legal obligation exists and the ARO can be reasonably estimated. These AROs are recognized at fair value as incurred or when sufficient information becomes available to determine fair value and are generally capitalized as part of the cost of the related long-lived assets pursuant to ASC 410. The Asset Retirement Cost ("ARC") is depreciated over those remaining useful lives of the assets. The ARO liability is adjusted for the passage of time by accreting the balance over the period from initial measurement to the expected timing of settlement. These changes are recognized as an increase in the carrying amount of the liability with a corresponding accretion expense recognized as a period cost in the income statement.

Q. Please discuss the various AROs reflected on the Company's books for financial reporting purposes.

A. The Company's AROs are primarily associated with the decommissioning of nuclear generation facilities and ash pond and landfill closures. Additionally, the Company has a number of other AROs primarily for asbestos removal and decommissioning of other fossil and renewable generating facilities. These AROs other than nuclear and CCR represent approximately 6% of the Company's outstanding ARO liability as of December 31, 2023.

Q. Has the Commission addressed how ARO accounting pursuant to ASC 410 should be treated for ratemaking purposes?

A. On April 8, 2004, the Company filed a statement of accounting treatment in Docket No. E-22, Sub 420 with respect to the adoption of Statement of Financial Accounting Standard ("SFAS") No. 143 (now codified as ASC 410). In its Order Allowing Utilization of Certain Accounts, the Commission stated the following regarding the ratemaking treatment of AROs:

> That the adoption of SFAS 143 shall have no impact upon [DENC]'s operating results or return on rate base for North Carolina retail regulatory purposes, and that the net effect of the deferral accounting allowed shall be to reset [DENC]'s North Carolina retail rate base, net operating income, and regulatory return on common equity to the same levels as would have existed had SFAS 143 not been implemented. Therefore, the intent and outcome of the deferral process shall be to continue the Commission's currently existing accounting and ratemaking practices for nuclear decommissioning costs and other ARO costs.[8]

For ratemaking purposes, the Company historically has reversed all entries made on its books in connection with ASC 410.

Q. How does the Company recover its North Carolina jurisdictional ARO costs for ratemaking purposes?

A. The Company has mechanisms to address recovery of the two largest categories of AROs for decommissioning of nuclear generation facilities and ash pond and landfill closures. Nuclear decommissioning costs are recovered through rates and the proceeds are placed in external trusts that will ultimately be used to pay the nuclear decommissioning costs when the plants reach the end of their useful lives. Ash pond and landfill closure expenditures have historically been deferred and amortized over a multi-year period.[9] However, for the remaining AROs, the Company currently does not have an established process for recovering other AROs.

---

[8] *Order Allowing Utilization of Certain Accounts,* Docket No. E-22, Sub 420, (Aug. 06, 2004) ("2004 ARO Accounting Order"), Ordering paragraph 2.

[9] The Company is proposing in this case to transition to treating CCR costs as operating expenses for ratemaking purposes beginning with expenditures incurred on and after November 1, 2024.

Q. How does the Company propose to recover the North Carolina jurisdictional ARO costs other than nuclear and CCR?

A. The Company proposes to begin recognizing ARO costs other than nuclear and CCR for ratemaking in the manner that they are recognized for financial reporting purposes. This requires inclusion of ARC depreciation and accretion expense in the revenue requirement along with ARC asset and ARO liability (and associated ADIT) in rate base.[10] This methodology works well for ratemaking as it aligns cost recovery of the ARO over the life of the asset. Over time, as the ARC asset is depreciated and carrying amount of ARO liability increases, rate base is reduced for ARO costs recovered from customers but remediation activities have not yet occurred. Once remediation activities have occurred, the liability is relieved and a gain or loss is recognized for the difference between the actual cost of settling the ARO and the recorded liability.

Q. Have any of the Company's other jurisdictions approved similar ratemaking treatment for ARO costs other than nuclear and CCR?

A. Yes. In its Virginia retail jurisdiction, the Company has alternative recovery mechanisms for nuclear and CCR AROs as it does in the North Carolina jurisdiction. All other ARO costs, however, are recognized in the Virginia jurisdiction for regulatory accounting and ratemaking purposes consistent with

[10] To the extent an ARO liability is established for property that has already reached end of life (*i.e.*, is no longer in service), the offset to the ARO liability is immediately charged to operating income.

financial reporting pursuant to ASC 410. The proposed treatment for these other ARO costs will therefore align treatment between the jurisdictions.

Q. Please discuss the Company's request for accounting treatment related to these "other" AROs.

A. The Company requests that the Commission allow the Company to recognize ASC 410 ARO costs for regulatory accounting and ratemaking purposes effective November 1, 2024, the effective date of interim rates in this case.

Q. How does the Company propose to reflect these in its cost of service for this case and in future cases?

A. In this case, the Company has ratemaking adjustments to remove all ARO expenses and rate base balances through a series of accounting adjustments. This is consistent with the Company's methodology in prior rate cases. Then, separate adjustments are made to add back in the expenses and rate base balances for other AROs not otherwise recovered by the Company through existing mechanisms. If the Commission approves the Company's request, the Company will no longer eliminate these AROs from its per books cost of service study results thereby reflecting the ASC 410 ARO costs for regulatory accounting and ratemaking purposes.

VII. NUCLEAR PTC DEFERRAL REQUEST

Q. Mr. McLeod, please discuss the Company's deferral request in this proceeding.

A. The Company is requesting approval to defer benefits from nuclear production tax credits (previously defined as "NPTC") pursuant to the Inflation Reduction Act ("IRA"). Under the new law, the Company's North Anna and Surry nuclear power stations may be eligible for significant benefits. However, the Company has not included any NPTC benefits in its revenue requirement in this case due to uncertainty with respect to the financial impacts. Instead, the Company requests the Commission allow for deferral of any benefits received, net of costs, to a regulatory liability account to be addressed in a future general rate case proceeding. NPTCs are expected to produce customer benefits by reducing the cost of nuclear production from the Company's North Anna and Surry Power Stations. The deferral ensures customers will receive any such benefits achieved between now and the Company's next rate case.

Q. Please briefly describe the IRA and provisions relating to NPTC.

A. On August 16, 2022, President Biden signed the IRA into law. The IRA introduces new and expands existing federal tax credits that are intended to incentivize the development and use of renewable and alternative carbon-free energy sources. Of relevance here, the IRA creates a new, zero emission nuclear power production credit under new IRC § 45U for producing electricity at a qualified nuclear power facility that is sold by the taxpayer to an unrelated person. The Company is currently waiting for guidance from the U.S. Treasury to provide clarity on how the NPTC is calculated.

Q. Why is deferral of NPTC to a regulatory liability account the appropriate mechanism for addressing these benefits in this proceeding?

A. Any benefits the Company realizes from NPTCs are expected to flow back to customers by reducing the Company's cost of service and revenue requirement in future rate cases; however, the exact amounts cannot be determined at this time until the U.S. Treasury issues further guidance. Establishment of the deferral will allow the Company to track and capture the actual benefits associated with NPTCs, net of costs, to be addressed in a future ratemaking proceeding.

VIII. CONCLUSION

Q. Mr. McLeod, please summarize your testimony.

A. My testimony supports the following:

1) The Company's fully-adjusted rate base for ratemaking purposes in this proceeding is $1.14 billion as depicted in Column 5 of Schedule 2 in Company Exhibit RA-1. As shown in Column 6 of Schedule 1 of Company Exhibit RA-1, the Company requires additional base non-fuel revenues of $56.6 million in order to achieve the Company's total base rate revenue requirement of $452.8 million as depicted in Column 7. This will provide the Company with just and reasonable rates that enable DENC to provide reliable and cost-effective electric service to

its North Carolina retail jurisdictional customers, recover its costs of providing that service, and earn an adequate rate of return on its investments.

2) The Company respectfully requests that the Commission approve its proposal to transition away from deferred recovery of CCR costs and incorporate an ongoing annual level of expenses in the base non-fuel rate cost of service.

3) The Company respectfully requests that the Commission approve the Company to begin recognizing certain ARO costs in a manner consistent with how they are recognized for financial reporting purposes.

4) The Company respectfully requests that the Commission allow the Company to defer NPTC benefits to a regulatory liability account to be addressed in a future rate case.

Q. Does this conclude your joint direct testimony?

A. Yes.

APPENDIX A

BACKGROUND AND QUALIFICATIONS
OF
PAUL M. MCLEOD

Paul M. McLeod joined the Company's Regulatory Accounting Group in 2015 and was promoted to his current position as Director – Regulatory Accounting in 2022. His responsibilities include overseeing the analysis and calculation of revenue requirements for Dominion Energy North Carolina.

Mr. McLeod graduated from Virginia Commonwealth University in 2010 with a Bachelor of Science degree in Accounting. He received an MBA from the College of William & Mary in 2018. Mr. McLeod is also a Certified Public Accountant licensed in Virginia. From 2010 through 2015, he was employed as an auditor with the Utility Accounting and Finance Division of the Virginia State Corporation Commission reviewing rate applications and compliance filings for electric, natural gas, and water utilities.

Mr. McLeod has previously presented testimony before the North Carolina Utilities Commission and Virginia State Corporation Commission.

APPENDIX B

BACKGROUND AND QUALIFICATIONS OF CHRISTOPHER J. LEE

Christopher J. Lee received a Bachelor of Science in Accounting from Virginia Commonwealth University in May 2000 and is a certified public accountant. Mr. Lee joined the Company in 2006 as a Senior Accountant in the Financial Reporting Department. He has held numerous accounting positions within the Company prior to joining the Regulatory Accounting Department in December 2018. His current position as Manager of Regulation in the Regulatory Accounting Department includes responsibility for analyzing, calculating and overseeing the development of revenue requirements for Dominion Energy North Carolina rate proceedings.

During his career with the Company, Mr. Lee has prepared and reviewed interrogatory responses, and analyzed revenue requirements for rate proceedings before the North Carolina Utilities Commission.

DOMINION ENERGY NORTH CAROLINA
DOCKET NO. E-22, SUB 694
RATE OF RETURN STATEMENT - ADJUSTED
TWELVE MONTHS ENDED DECEMBER 31, 2023
(Thousands of Dollars)

Line No.			(Col. 1) Total Company	(Col. 2) Non-Jurisdictional	(Col. 3) North Carolina Jurisdictional Cost of Service (1) - (2)	(Col. 4) Accounting Adjustments	(Col. 5) North Carolina Jurisdictional Cost of Service After Adjustments (3) + (4)	(Col. 6) Additional Revenue Required for a 10.60% ROE	(Col. 7) North Carolina Jurisdictional Amounts After Proposed Increase (5) + (6)
1	**OPERATING REVENUE**								
2	Base Non-Fuel Rate Revenues		$ 6,098,973	$ 5,847,607	$ 251,366	$ 3,236	$ 254,603	$ 56,883	$ 311,486
3	Base Fuel Rate Revenues		2,936,349	2,784,105	152,244	(15,291)	136,953		136,953
4	Late Payment Fees		16,434	15,760	674	43	717	95	811
5	Other Operating Revenues		449,034	445,122	3,912	(11)	3,901	(354)	3,548
6	**TOTAL OPERATING REVENUE**		$ 9,500,791	$ 9,092,595	$ 408,196	$ (12,023)	$ 396,174	$ 56,624	$ 452,798
7	**OPERATING REVENUE DEDUCTIONS**								
8	Fuel Expenses		2,543,614	2,389,106	154,508	(17,757)	136,751		136,751
9	Other Operation & Maintenance Expense		2,078,584	1,993,952	84,631	17,433	102,064	$ 495	102,559
10	Depreciation & Amortization		2,052,595	1,975,628	76,967	(39)	76,928		76,928
11	Federal Income Taxes		259,078	255,311	3,767	(673)	3,093	11,108	14,201
12	State Income Taxes		104,694	102,399	2,295	(197)	2,098	3,236	5,334
13	Taxes Other Than Income Taxes		298,505	285,870	12,636	510	13,145		13,145
14	(Gain)/Loss on Disposition of Property		3,529	3,373	156	(245)	(89)		(89)
15	**TOTAL OPERATING REVENUE DEDUCTIONS**		$ 7,340,600	$ 7,005,640	$ 334,960	$ (969)	$ 333,991	$ 14,838	$ 348,829
16	**OPERATING INCOME**		$ 2,160,191	$ 2,086,955	$ 73,237	$ (11,054)	$ 62,183	$ 41,785	$ 103,968
17	PLUS: Allowance for Funds Used During Construction		99,281	85,173	14,108	(14,108)	-		-
18	LESS: Charitable Donations		7,637	7,239	398	(398)	-		-
19	Interest Expense On Customer Deposits		1,134	1,103	31	-	31		31
20	Other Interest Expense/Income		4,912	4,699	213	-	213		213
21	**ADJUSTED OPERATING INCOME**		$ 2,245,790	$ 2,159,087	$ 86,703	$ (24,764)	$ 61,939	$ 41,785	$ 103,725
22	PLUS: Other Income/(Expenses)		45,103	45,103	-	-	-		-
23	LESS: Interest Expense on Debt	(1)	839,217	808,015	31,202	(5,179)	26,023	454	26,477
24	**INCOME AVAILABLE FOR COMMON EQUITY**		$ 1,451,676	$ 1,396,175	$ 55,501	$ (19,585)	$ 35,916	$ 41,332	$ 77,248
25	Allowance for Working Capital		(3,077,379)	(3,172,404)	95,025	13,162	108,187	23,201	131,388
26	PLUS: Net Utility Plant		43,086,818	41,290,827	1,795,991	(309,482)	1,486,509		1,486,509
27	LESS: Other Rate Base Deductions		6,587,338	6,291,173	296,165	(31,594)	264,570		264,570
28	**TOTAL RATE BASE**		$ 33,422,102	$ 31,827,250	$ 1,594,852	$ (264,726)	$ 1,330,125	$ 23,201	$ 1,353,326
29	Total Capital		$ 33,422,102	$ 31,827,250	$ 1,594,852	$ (264,726)	$ 1,330,125		$ 1,353,326
30	Common Equity Capital		$ 17,997,490	$ 17,138,678	$ 858,813	$ (142,552)	$ 716,260		$ 728,754
31	% Rate of Return Earned on Rate Base				5.44%		4.66%		7.66%
32	% Rate Of Return Earned On Common Equity				6.46%		5.01%		10.60%
33	% Rate of Return Requested						10.60%		10.60%

Notes:
(1) NC Jurisdictional Interest Expense = NC Jurisdictional Year End Rate Base * Debt Weighted Cost of Capital Percentage
$31,202 = $ 1,594,852 * 1.956%

DOMINION ENERGY NORTH CAROLINA
DOCKET NO. E-22, SUB 694
RATE BASE STATEMENT - ADJUSTED
TWELVE MONTHS ENDED DECEMBER 31, 2023
(Thousands of Dollars)

Line No.		(Col. 1) Total Company	(Col. 2) Non-Jurisdictional	(Col. 3) North Carolina Jurisdictional Cost of Service (1)-(2)	(Col. 4) Accounting Adjustments	(Col. 5) North Carolina Jurisdictional Cost of Service After Adjustments (3)+(4)
1	ALLOWANCE FOR WORKING CAPITAL					
2	Materials & Supplies	$ 1,187,574	$ 1,136,840	$ 50,733	$ -	$ 50,733
3	Investor Funds Advanced	364,880	349,088	15,792	24,555	40,346
4	Total Additions	842,687	578,147	264,540	(212,292)	52,248
5	Total Deductions	(5,472,519)	(5,236,479)	(236,040)	200,899	(35,141)
6	TOTAL ALLOWANCE FOR WORKING CAPITAL	$ (3,077,379)	$ (3,172,404)	$ 95,025	$ 13,162	$ 108,187
7	NET UTILITY PLANT					
8	Utility Plant in Service	$ 53,644,013	$ 51,374,865	$ 2,269,148	$ 90,050	$ 2,359,198
9	Acquisition Adjustments	52,041	51,728	313	(313)	-
10	Construction Work in Progress	8,022,233	7,661,887	360,345	(360,345)	-
11	Less: Accumulated Provision for Depreciation &					
12	Amortization	18,587,167	17,753,405	833,762	38,927	872,689
13	Provision for Acquisition Adjustments	44,302	44,248	53	(53)	-
14	TOTAL NET UTILITY PLANT	$ 43,086,818	$ 41,290,827	$ 1,795,991	$ (309,482)	$ 1,486,509
15	OTHER RATE BASE DEDUCTIONS					
16	Customer Deposits	$ 114,643	$ 111,507	$ 3,136	$ -	$ 3,136
17	Accumulated Deferred Income Taxes	4,112,057	3,926,611	185,446	(29,846)	155,600
18	Other Cost Free Capital	2,360,638	2,253,055	107,583	(1,748)	105,835
19	TOTAL OTHER RATE BASE DEDUCTIONS	$ 6,587,338	$ 6,291,173	$ 296,165	$ (31,594)	$ 264,570
20	**TOTAL RATE BASE**	**$ 33,422,102**	**$ 31,827,250**	**$ 1,594,852**	**$ (264,726)**	**$ 1,330,125**

DOMINION ENERGY NORTH CAROLINA
DOCKET NO. E-22, SUB 694
DETAIL OF ADJUSTMENTS
REFLECTED IN COLUMN 4 OF SCHEDULES 1 AND 2
(Thousands of Dollars)

Adjustment Number	Description	Amount
	OPERATING REVENUE	
	Base Non-Fuel Rate Revenues	
NC-1	Annualize Revenue for Usage, Weather, and Customer Growth as of June 30, 2024	7,841
NC-2	Eliminate DSM and REPS Rider Revenues	(4,604)
	Total Adjustments to Non-Fuel Rate Revenues	**3,236**
	Base Fuel Rate Revenues	
NC-3	Annualize Fuel Revenues & Expenses at Current Rates	(15,291)
	Total Adjustments to Base Fuel Rate Revenues	**(15,291)**
	Late Payment Fees	
NC-4	Annualize Revenue for Usage, Weather, and Customer Growth as of June 30, 2024	43
	Total Adjustments to Late Payment Fees	**43**
	Other Operating Revenues	
NC-5	Adjust Ancillary Services Margins	79
NC-6	Annualize Revenue for Usage, Weather, and Customer Growth as of June 30, 2024	9
NC-7	Annualize Fuel Revenues & Expenses at Current Rates	(99)
	Total Adjustments to Other Operating Revenues	**(11)**
	TOTAL ADJUSTMENTS TO OPERATING REVENUE	**(12,023)**
	OPERATING REVENUE DEDUCTIONS	
	Fuel Expenses	
NC-8	Annualize Fuel Revenues & Expenses at Current Rates	**(17,757)**
	Other Operation & Maintenance Expense	
NC-9	Eliminate DSM and REPS Rider Costs	(1,139)
NC-10	Eliminate the Effects of ASC 410-20 -- Asset Retirement Obligations	0
NC-11	Update Purchased Power Capacity	2,306
NC-12	Update Purchased Power Energy	1,158
NC-13	Levelize Nuclear Refueling and Maintenance Outage Expense	(385)
NC-14	Annualize Salary and Wages as of June 30, 2024 - Salaried Payroll	649
NC-15	Annualize Salary and Wages as of June 30, 2024 - Hourly Payroll	184
NC-16	Annualize Salary and Wages as of June 30, 2024 - Services Company	778
NC-17	Adjust Employee Benefits Costs to June 30, 2024	953
NC-18	Normalize Annual Incentive Plan Costs	(36)
NC-19	Adjust Executive Compensation	(55)
NC-20	Normalize Storm Expense	1,247
NC-21	Eliminate Promotional Advertising Expenses	(73)
NC-22	Reclassify Certain Non-Operating Expenses	(17)

DOMINION ENERGY NORTH CAROLINA
DOCKET NO. E-22, SUB 694
DETAIL OF ADJUSTMENTS
REFLECTED IN COLUMN 4 OF SCHEDULES 1 AND 2
(Thousands of Dollars)

Adjustment Number	Description	Amount
NC-23	Adjust Certain Operating & Maintenance Expenses for Inflation	612
NC-24	North Carolina Regulatory Fee	19
NC-25	Adjust North Carolina Regulatory Fee for Annualization of Fuel Revenue	(23)
NC-26	AMI Opt-Out Expense	61
NC-27	Amortize Retired Plant Closure Costs	1,698
NC-28	Amortize Retired Plant Inventory	974
NC-29	Annualize On-Going Coal Combustion Residual Expenditures	9,005
NC-30	Eliminate Chesterfield Power Station and Yorktown Power Station Net Operating Expense	(483)
	Total Adjustments to Other Operation & Maintenance Expenses	**17,433**
	Depreciation & Amortization	
NC-31	Eliminate the Effects of ASC 410-20 -- Asset Retirement Obligations	(5,448)
NC-32	Eliminate Acquisition Adjustments	(7)
NC-33	Annualize Depreciation Expense	3,570
NC-34	Eliminate Incremental Costs for Certain Underground Transmission Projects	(129)
NC-35	Eliminate AC Cycling Program Costs	(10)
NC-36	Amortize Retired Plant Impairment Regulatory Asset	1,111
NC-37	Amortize CCR ARO Regulatory Asset	5,728
NC-38	Adjust Existing Regulatory Assets	(5,421)
NC-39	Incorporate Other Certain AROs	566
	Total Adjustments to Depreciation & Amortization	**(39)**
	Federal Income Tax Expense	
NC-40	Interest Synchronization Adjustment - Federal	1,683
NC-41	Federal Income Tax Effect of Adjustments	(2,360)
NC-42	Eliminate the Effect of FIN 48	0
NC-43	Eliminate Incremental Costs for Certain Underground Transmission Projects	3
NC-44	Eliminate AC Cycling Program Costs	0
	Total Adjustments to Federal Income Tax Expense	**(673)**
	State Income Tax Expense	
NC-45	Interest Synchronization Adjustment - State	490
NC-46	State Income Tax Effect of Adjustments	(687)
NC-47	Eliminate the Effect of FIN 48	0
	Total Adjustments to State Income Tax Expense	**(197)**

DOMINION ENERGY NORTH CAROLINA
DOCKET NO. E-22, SUB 694
DETAIL OF ADJUSTMENTS
REFLECTED IN COLUMN 4 OF SCHEDULES 1 AND 2
(Thousands of Dollars)

Adjustment Number	Description	Amount
	Taxes Other Than Income Taxes	
NC-48	Annualize Property Taxes Based on Plant in Service as of June 30, 2024	389
NC-49	Adjust Payroll Tax for Incremental Payroll	120
	Total Adjustments to Taxes Other than Income Taxes	**510**
	Gain/Loss on Disposition of Property	
NC-50	Eliminate the Effects of ASC 410-20 -- Asset Retirement Obligations	(245)
	Total Adjustments to Gain/Loss on Disposition of Property	**(245)**
	TOTAL ADJUSTMENTS TO OPERATING REVENUE DEDUCTIONS	**(969)**
	TOTAL ADJUSTMENTS TO OPERATING INCOME	**(11,054)**
	Allowance for Funds Used During Construction	
NC-51	Eliminate AFUDC Income	(14,108)
	Charitable Donations	
NC-52	Eliminate Charitable Contributions	(398)
	TOTAL ADJUSTMENTS TO ADJUSTED OPERATING INCOME	**(24,764)**
	Interest Expense	
NC-53	Reflect Interest Expense Based on Proposed Capital Structure, Debt Costs, and Adjusted Rate Base	(5,179)
	TOTAL ADJUSTMENTS TO INCOME AVAILABLE FOR COMMON EQUITY	**(19,585)**
	ALLOWANCE FOR WORKING CAPITAL	
	Investor Funds Advanced	
NC-54	Cash Working Capital Effect of Lead/Lag Study and Accounting Adjustments	24,555
	Total Adjustments to Investor Funds Advanced	**24,555**
	Total Additions	
NC-55	Adjust Existing Regulatory Assets	(231,467)
NC-56	Adjust Rate Base for New Regulatory Assets	22,984
NC-57	Eliminate Nuclear Outage Deferral Balance & Joint Owner Receivables	(3,809)
	Total Adjustments to Total Additions	**(212,292)**
	Total Deductions	
NC-58	Eliminate the Effects of ASC 410-20 -- Asset Retirement Obligations	189,529
NC-59	Eliminate CWIP Accounts Payable and Accrued Payroll	22,701
NC-60	Incorporate Other Certain AROs	(11,330)
	Total Adjustments to Total Deductions	**200,899**
	TOTAL ADJUSTMENTS TO ALLOWANCE FOR WORKING CAPITAL	**13,162**

DOMINION ENERGY NORTH CAROLINA
DOCKET NO. E-22, SUB 694
DETAIL OF ADJUSTMENTS
REFLECTED IN COLUMN 4 OF SCHEDULES 1 AND 2
(Thousands of Dollars)

Adjustment Number	Description	Amount
	NET UTILITY PLANT	
	Utility Plant in Service	
NC-61	Eliminate the Effects of ASC 410-20 -- Asset Retirement Obligations	5,701
NC-62	Update Plant in Service to June 30, 2024	85,291
NC-63	Eliminate Incremental Costs for Certain Underground Transmission Projects	(4,890)
NC-64	Eliminate AC Cycling Program Costs	0
NC-65	Incorporate Other Certain AROs	3,947
	Total Adjustments to Utility Plant in Service	**90,050**
	Acquisition Adjustments	
NC-66	Eliminate Acquisition Adjustments	(313)
	Total Adjustments to Acquisition Adjustments	**(313)**
	Construction Work In Progress	
NC-67	Eliminate CWIP Balance	(360,345)
	Total Adjustments to Construction Work In Progress	**(360,345)**
	Accumulated Provision for Depreciation & Amortization	
NC-68	Eliminate the Effects of ASC 410-20 -- Asset Retirement Obligations	813
NC-69	Update Accumulated Provision for Depreciation and Amortization to June 30, 2024	35,158
NC-70	Annualize Depreciation Expense	3,570
NC-71	Eliminate Incremental Costs for Certain Underground Transmission Projects	(1,391)
NC-72	Eliminate AC Cycling Program Costs	0
NC-73	Incorporate Other Certain AROs	776
	Total Adjustments to Accumulated Provision for Depreciation & Amortization	**38,927**
	Accumulated Provision for Acquistion Adjustments	
NC-74	Eliminate Acquisition Adjustments	(53)
	Total Adjustments to Accumulated Provision for Acquistion Adjustments	**(53)**
	TOTAL ADJUSTMENTS TO NET UTILITY PLANT	**(309,482)**
	OTHER RATE BASE DEDUCTIONS	
	Accumulated Deferred Income Taxes	
NC-75	Eliminate the Effects of ASC 410-20 -- Asset Retirement Obligations	52,459
NC-76	Eliminate Acquisition Adjustments	0
NC-77	Update Accumulated Deferred Income Taxes to June 30, 2024	5,812
NC-78	Annualize Depreciation Expense	(912)
NC-79	Eliminate AC Cycling Program Costs	1,581
NC-80	Eliminate Deferred Fuel ADIT	(9,486)
NC-81	Eliminate Nuclear Outage Deferral Balance	(799)

DOMINION ENERGY NORTH CAROLINA
DOCKET NO. E-22, SUB 694
DETAIL OF ADJUSTMENTS
REFLECTED IN COLUMN 4 OF SCHEDULES 1 AND 2
(Thousands of Dollars)

Adjustment Number	Description	Amount
NC-82	Eliminate Other Nuclear Decommissioning ADIT	(22,580)
NC-83	Eliminate Incremental Costs for Certain Underground Transmission Projects	(952)
NC-84	Adjust Existing Regulatory Assets	(58,668)
NC-85	Adjust Rate Base for New Regulatory Assets	5,873
NC-86	Update Excess Deferred Income Taxes to June 30, 2024	(1,748)
NC-87	Incorporate Other Certain AROs	(2,173)
	Total Adjustments to Accumulated Deferred Income Taxes	**(31,594)**
	TOTAL ADJUSTMENTS TO OTHER RATE BASE DEDUCTIONS	**(31,594)**
	TOTAL ADJUSTMENTS TO RATE BASE	**(264,726)**

DOMINION ENERGY NORTH CAROLINA
DOCKET NO. E-22, SUB 694
LEAD/LAG CASH WORKING CAPITAL CALCULATION - ADJUSTED
TWELVE MONTHS ENDED DECEMBER 31, 2023
(Thousands of Dollars)

Line No.	Item	(Col. 1) NC Retail Per Books Amounts	(Col. 2) Accounting Adjustments	(Col. 3) Amounts After Adjustments	(Col. 4) Average Daily Amounts	(Col. 5) (Lead) / Lag Days	(Col. 6) Working Capital (Provided)/ Required
1	Operating Revenue						
2	Rate Revenues	$ 403,611	$ (12,055)	$ 391,555	$ 1,073	60.23	$ 64,614
3	Sales for Resale	827	-	827	2	40.15	91
4	Other Operating Revenue	3,759	32	3,791	10	28.68	298
5	Total Operating Revenue	$ 408,196	$ (12,023)	$ 396,174			$ 65,003
6	Operation & Maintenance Expense						
7	Account 501 - Fuel	$ 12,676	$ 5,897	$ 18,573	51	(34.78)	$ (1,770)
8	Account 518 - Nuclear Fuel	6,935	3,226	10,161	28	(0.59)	(16)
9	Account 547 - Other Fuel	41,199	19,167	60,366	165	(34.78)	(5,752)
10	Account 555 - Purchased Power	41,359	19,241	60,600	166	(15.77)	(2,618)
11	Account 557 - Deferred Fuel	65,289	(65,289)	-	-	-	-
12	Payroll Expense	21,016	1,574	22,590	62	(28.43)	(1,760)
13	Benefits and Pension Expense	3,342	953	4,295	12	(35.22)	(414)
14	OPEB Expense	(1,584)	-	(1,584)	(4)	(59.78)	259
15	Uncollectible Expense	2,940	-	2,940	8	(428.87)	(3,454)
16	Stores Expense	10,392	-	10,392	28	(51.92)	(1,478)
17	Accrued Vacation Expense	116	-	116	0	-	-
18	Worker's Compensation Expense	57	-	57	0	-	-
19	Prepaid Insurance Amortization Expense	774	-	774	2	-	-
20	Director's Deferred Compensation Expense	1	-	1	0	-	-
21	Miscellaneous Prepaid Expense	466	-	466	1	-	-
22	Other O&M Expense	34,161	14,906	49,067	134	(48.30)	(6,494)
23	Total Operation & Maintenance Expense	$ 239,139	$ (324)	$ 238,815			$ (23,497)
24	Depreciation & Amortization Expense	$ 76,967	$ (39)	$ 76,928	211	-	$ -
25	Income Tax Expense						
26	Current Federal & State Income Taxes	$ 7,317	$ (870)	$ 6,447	18	367.58	$ 6,492
27	Deferred Federal & State Income Taxes	(1,396)	-	(1,396)	(4)	-	-
28	Deferred ITC	141	-	141	0	-	-
29	Total Income Tax Expense	$ 6,062	$ (870)	$ 5,192			$ 6,492
30	Taxes Other Than Income Taxes						
31	North Carolina Franchise Tax	$ 0	$ -	$ 0	0	(166.50)	$ (0)
32	Property Tax Expense	10,381	389	10,770	30	(113.20)	(3,340)
33	West Virginia B&O Tax Expense	371	-	371	1	(41.26)	(42)
34	Payroll Taxes	1,862	120	1,982	5	(28.74)	(156)
35	Other Taxes	22	-	22	0	(91.10)	(5)
36	Total Taxes Other than Income	$ 12,636	$ 510	$ 13,145			$ (3,544)
37	Gain/Loss on Disposition of Property	$ 156	$ (245)	$ (89)	(0)	-	$ -
38	Total Operating Revenue Deductions	$ 334,960	$ (969)	$ 333,991			$ (20,549)
39	AFUDC	$ 14,108	$ (14,108)	-	-	-	$ -
40	Charitable Donations	398	(398)	-	-	-	-
41	Interest on Customer Deposits	31	-	31	0	(182.50)	(16)
42	Interest of Tax Deficiencies	213	-	213	1	-	-
							-
43	Interest Expense on Debt	31,202	(5,179)	26,023	71	(91.21)	(6,503)
44	Income Available for Common Equity	55,501	(19,585)	35,916	98	-	-
45	Total Requirement	$ 408,196	$ (12,023)	$ 396,174			$ (27,067)
46	Cash Working Capital from Operations (Line 5 + Line 45)						$ 37,936
47	Plus: Customer Utility Taxes						2,410
48	**TOTAL CASH WORKING CAPITAL**						$ 40,346

DOMINION ENERGY NORTH CAROLINA
DOCKET NO. E-22, SUB 694
LEAD/LAG CASH WORKING CAPITAL CALCULATION - ADDITIONAL REVENUE REQUIREMENT
TWELVE MONTHS ENDED DECEMBER 31, 2023
(Thousands of Dollars)

		(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)	(Col. 12)	(Col. 13)
				Iteration 1			Iteration 2			Iteration 3			After Increase	
Line No.	Item	NC Retail Amounts Adjustments	Net (Lead) / Lag Days	Increase	With Increase	CWC Change	Increase	With Increase	CWC Change	Increase	With Increase	CWC Change	Cumulative Increase	After Increase
1	Operating Revenue													
2	Rate Revenues	$ 391,555	60.23	$ 54,477	$ 446,032	$ 8,990	$ 2,315	$ 448,347	$ 382	$ 88	$ 448,435	$ 14	$ 56,879	$ 448,435
3	Sales for Resale	827	40.15	-	827	-	-	827	-	-	827	-	-	827
4	Other Operating Revenue	3,791	28.68	(262)	3,529	(21)	4	3,533	0	0	3,533	0	(258)	3,533
5	Total Operating Revenue	$ 396,174		$ 54,214	$ 450,388	$ 8,969	$ 2,319	$ 452,706	$ 382	$ 88	$ 452,794	$ 14	$ 56,621	$ 452,794
6	Operation & Maintenance Expense													
7	Account 501 - Fuel	$ 18,573	(34.78)	$ -	$ 18,573	$ -	$ -	$ 18,573	$ -	$ -	$ 18,573	$ -	$ -	$ 18,573
8	Account 518 - Nuclear Fuel	10,161	(0.59)	-	10,161	-	-	10,161	-	-	10,161	-	-	10,161
9	Account 547 - Other Fuel	60,366	(34.78)	-	60,366	-	-	60,366	-	-	60,366	-	-	60,366
10	Account 555 - Purchased Power	60,600	(15.77)	-	60,600	-	-	60,600	-	-	60,600	-	-	60,600
11	Account 557 - Deferred Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Payroll Expense	22,590	(28.43)	-	22,590	-	-	22,590	-	-	22,590	-	-	22,590
13	Benefits and Pension Expense	4,295	(35.22)	-	4,295	-	-	4,295	-	-	4,295	-	-	4,295
14	OPEB Expense	(1,584)	(59.78)	-	(1,584)	-	-	(1,584)	-	-	(1,584)	-	-	(1,584)
15	Uncollectible Expense	2,940	(428.87)	395	3,334	(464)	17	3,351	(20)	1	3,352	(1)	412	3,352
16	Stores Expense	10,392	(51.92)	-	10,392	-	-	10,392	-	-	10,392	-	-	10,392
17	Accrued Vacation Expense	116	-	-	116	-	-	116	-	-	116	-	-	116
18	Worker's Compensation Expense	57	-	-	57	-	-	57	-	-	57	-	-	57
19	Prepaid Insurance Amortization Expense	774	-	-	774	-	-	774	-	-	774	-	-	774
20	Director's Deferred Compensation Expense	1	-	-	1	-	-	1	-	-	1	-	-	1
21	Miscellaneous Prepaid Expense	466	-	-	466	-	-	466	-	-	466	-	-	466
22	Other O&M Expense	49,067	(48.30)	79	49,146	(11)	3	49,150	(0)	0	49,150	(0)	83	49,150
23	Total Operation & Maintenance Expense	$ 238,815		$ 474	$ 239,289	$ (474)	$ 20	$ 239,309	$ (20)	$ 1	$ 239,310	$ (1)	$ 495	$ 239,310
24	Depreciation & Amortization Expense	$ 76,928	-	$ -	$ 76,928	$ -	$ -	$ 76,928	$ -	$ -	$ 76,928	$ -	$ -	$ 76,928
25	Income Tax Expense													
26	Current Federal & State Income Taxes	$ 6,447	367.58	$ 13,733	$ 20,180	$ 13,830	$ 587	$ 20,767	$ 591	$ 22	20,789	22	14,342	20,789
27	Deferred Federal & State Income Taxes	(1,396)	-	-	(1,396)	-	-	(1,396)	-	-	(1,396)	-	-	(1,396)
28	Deferred ITC	141	-	-	141	-	-	141	-	-	141	-	-	141
29	Total Income Tax Expense	$ 5,192		$ 13,733	$ 18,925	$ 13,830	$ 587	$ 19,512	$ 591	$ 22	$ 19,534	$ 22	$ 14,342	$ 19,534
30	Taxes Other Than Income Taxes													
31	North Carolina Franchise Tax	0	(166.50)	-	0	-	-	0	-	-	0	-	-	0
32	Property Tax Expense	10,770	(113.20)	-	10,770	-	-	10,770	-	-	10,770	-	-	10,770
33	West Virginia B&O Tax Expense	371	(41.26)	-	371	-	-	371	-	-	371	-	-	371
34	Payroll Taxes	1,982	(28.74)	-	1,982	-	-	1,982	-	-	1,982	-	-	1,982
35	Other Taxes	22	(91.10)	-	22	-	-	22	-	-	22	-	-	22
36	Total Taxes Other than Income	$ 13,145		$ -	$ 13,145	$ -	$ -	$ 13,145	$ -	$ -	$ 13,145	$ -	$ -	$ 13,145
37	Gain/Loss on Disposition of Property	$ (89)	-	$ -	$ (89)	$ -	$ -	$ (89)	$ -	$ -	$ (89)	$ -	$ -	$ (89)
38	Total Operating Revenue Deductions	$ 333,991		$ 14,207	$ 348,198	$ 13,355	$ 608	$ 348,805	$ 571	$ 23	$ 348,828	$ 22	$ 14,838	$ 348,828
39	AFUDC	-	-											
40	Charitable Donations	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Interest on Customer Deposits	31	(182.50)	-	31	-	-	31	-	-	31	-	-	31
42	Other Expense/Income	213	-	-	213	-	-	213	-	-	213	-	-	213
43	Interest Expense on Debt	26,023	(91.21)	-	26,023	-	437	26,460	(109)	17	26,476	(4)	453	26,476
44	Income Available for Common Equity	35,916	-	40,007	75,924	-	1,274	77,198	0	48	77,246	0	41,330	77,246
45	**Total Requirement**	$ 396,174		$ 54,214	$ 450,388	$ 13,355	$ 2,319	$ 452,706	$ 462	$ 88	$ 452,794	$ 17	$ 56,621	$ 452,794
46	Cumulative change in working capital					$ 22,325			23,169			23,201		23,201
47	Common equity capital under present rates	1,330,125				1,330,125			1,330,125			1,330,125		1,330,125
48	Common equity capital after rate increase					1,352,450			1,353,294			1,353,326		1,353,326
49	Overall rate of return	4.657%				7.538%			7.660%			7.664%		7.664%
50	Target rate of return	7.664%				7.664%			7.664%			7.664%		7.664%

DIRECT TESTIMONY
OF
C. ALAN GIVENS
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 694

Q. Please state your name, position of employment, and business address.

A. My name is C. Alan Givens, and my business address is 120 Tredegar Street, Richmond, Virginia 23219. My title is Manager – Regulation Rate Design for Dominion Energy North Carolina ("DENC" or the "Company").

Q. Please describe your area of responsibility within the Company.

A. I am responsible for the Company's rate design activities, including the preparation and support of the Company's various rate filings and the implementation of rates. A statement of my background and qualifications is attached as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes. I have provided testimony on behalf of the Company in a number of annual DSM/EE cost recovery (Docket No. E-22, Subs 494, 513, 524, and 536) and REPS cost recovery (Docket No. E-22, Subs 503, 514, 525, and 535) proceedings.

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

A. The primary purpose of my testimony is to i) address the Company's proposed apportionment of the non-fuel base rate revenue requirement increase among the customer classes, ii) then to revise DENC's base rates, inclusive of changes in base fuel and non-fuel cost recovery, and charges specified in the Company's Terms and Conditions in order to produce the additional revenues being sought by the Company through its Application, and iii) present the Company's proposed new experimental small general service ("SGS") rate schedule, designated Schedule SGS-EV to address, promote, and incentivize third party development and investment in electric vehicle ("EV") charging.

Finally, I address how the Company's proposed non-fuel base, base fuel and the projected EMF fuel adjustments will impact customers' rates.

Q. How is your testimony organized?

A. I have divided my testimony into the following sections:

I. BASE RATES

II. APPORTIONMENT OF NON-FUEL BASE RATE INCREASE AND PROPOSED RATE DESIGN

III. SUMMARY SHEET AND TYPICAL BILLS

IV. RATE SCHEDULES

V. EXPERIMENTAL SMALL GENERAL SERVICES RATE SCHEDULE

VI. TERMS AND CONDITIONS AND EXISTING RIDERS

VII. RULE R-17 AND E-1 REQUIREMENTS

Q. Will you introduce any exhibits as part of your testimony?

A. Yes. I am sponsoring Company Exhibit CAG-1. Company Exhibit CAG-1, consisting of Schedules 1 through 6, was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief. Each schedule is identified and described below:

- Page 1 of my Schedule 1 shows the proposed non-fuel base rate revenue increase for the North Carolina jurisdiction. This page shows the changes in revenue associated with various miscellaneous items such as late payment charges, miscellaneous service charges, and facilities charges. These changes in various miscellaneous items are subtracted from the jurisdictional revenue increase to calculate the change in revenue to be recovered from the rate schedules, including the Company's Rider EDR tariff. This page then develops target proposed changes in base non-fuel revenue for the customer classes to be recovered from the rate schedules within each customer class as well as the resulting percentage change compared to present revenue. Page 2 of my Schedule 1 presents the summary of final rate design that reflects all adjustments made to the target revenue changes developed on Page 1 based on an analysis of the rate design for each rate schedule and for each element within each rate schedule. This summary of final rate design presented in Page 2 shows on lines 54 – 57 the final present and proposed total revenues, including fuel and all riders, and the resulting change and percentage change for each customer class and the North Carolina jurisdiction.
- My Schedule 2 shows the class rates of return and their indices before and after the apportionment of the non-fuel base rate revenue increase.

- My Schedule 3 presents a summary sheet showing the change in non-fuel base rate revenue or basic revenue amounts compared to total current revenues and their corresponding percent changes for each rate schedule and for the various miscellaneous revenue items discussed above.
- My Schedule 4 presents a summary sheet showing the change in base rate revenue amounts, including non-fuel and base-fuel revenues, the projected change in total fuel revenue compared to total current revenues and their corresponding percent changes for each rate schedule and for the various miscellaneous revenue items discussed above.
- My Schedule 5 provides the rate design and supporting workpapers for the proposed new experimental small general service rate.
- My Schedule 6 provides a list of changes in the Terms and Conditions, including changes to proposed miscellaneous service charges, that the Company is proposing to update in this docket.

Finally, I am sponsoring Company Appendix 1, Company Exhibit I and Company Exhibit II as required by Rule R1-17 and Items 39 a.–c., 40, and 42 a.–c. that are included in the Company's Form E-1. In conjunction with Item 42 a., I am sponsoring the revenue adjustment associated with customer growth, changes in usage, and weather normalization.

I. BASE RATES

Q. What is the total increase in non-fuel base rate revenues that the Company is seeking in this proceeding?

A. As presented in Company Witness Paul M. McLeod's RA-1, Schedule 1 Schedule 1, the Company is requesting to increase total annual non-fuel base rate revenues by $56.624 million.

Q. Does the proposed total annual non-fuel base rate revenue increase include the Company's proposed rate changes for the "miscellaneous charges," *i.e.*, proposed rate changes associated with excess facilities charges, late payment charges, and other miscellaneous non-rate schedule charges contained in the Company's Terms and Conditions?

A. Yes. The Company first subtracts the aggregate revenue increase associated with the proposed rate changes for these miscellaneous charges/revenues and Rider EDR of approximately ($337) thousand from the proposed annual non-fuel base rate revenue increase of $56.624 million. The remainder of the non-fuel base rate revenue increase of $56.961 million is then apportioned to the customer classes in accordance with my Schedule 1. As I describe later, the apportioned revenue requirement will be recovered through increased charges in the Company's rate schedules.

II A. APPORTIONMENT OF NON-FUEL BASE RATE INCREASE

Q. What is the Company's goal in apportioning the revenue requirement among its customer classes?

A. The Company's overall goal is to fairly apportion the revenue requirement in a way that moves the classes towards parity with the jurisdictional rate of return ("ROR"), while also considering other factors that impact customers and the jurisdiction. Ultimately, revenue apportionment and rate design should provide the means to recover just and reasonable utility system costs in a manner that is:

(i) consistent with the ways costs are incurred;

(ii) fair to the entire body of customers;

(iii) fair to each customer class;

(iv) fair to customers within an individual class; and

(v) fair to the utility's shareholders.

These concepts attempt to recognize a need to recover costs in a manner that is fair to all system customers, in a way that avoids arbitrariness while promoting stability and predictability of rates. To achieve the goal of moving toward parity, the Company first reviewed the existing class rates of return, which are shown in Company Witness Robert Miller's Schedules 8, 14, 20, and 26. Pages 1-4 of my Schedule 2 duplicate this information and provide the customer class rates of return, and their respective rate of return indices (class rate of return / jurisdictional rate of return), from the Company's class cost of service study.

As discussed by Company Witness Miller, the Company has prepared four cost of service studies as presented in his Schedules 8, 14, 20 and 26 for the Summer Winter Peak and Average ("SWPA") method, the Summer Winter

Coincident Peak ("SWCP") method, the Average and Excess Baseline ("A&E") method and the Modified Average and Excess ("Modified A&E") method respectively, using the following allocation methodologies to allocate production and transmission demand fixed costs and related expenses:

i) SWPA method used to allocate both system costs to the Company's jurisdictions and to the North Carolina customer classes,

ii) SWPA method used to allocate system costs to the Company's jurisdictions and then use the SWCP method to allocate North Carolina jurisdictional costs to the customer classes,

iii) SWPA method used to allocate system costs to the Company's jurisdictions and then use the A&E method to allocate North Carolina jurisdictional costs to the customer classes, and

iv) SWPA method used to allocate system costs to the Company's jurisdictions and then use the Modified A&E method to allocate North Carolina jurisdictional costs to the customer classes.[1]

The top fourth of this exhibit shows the "per-books" rates of return, prior to any ratemaking adjustments. The second fourth shows the per-books rates of

[1] Company Witness Miller explains the Modified A&E method in his testimony. Effectively, Mr. Miller has replaced the class peak demand for the 6VP and NS customer classes with their average demand in the calculation of this method. Under the traditional A&E, the class peak demand is the highest demand measured during any hour of the year for these respective classes. This level of demand does not reflect the specific operating arrangements and rate schedule provisions of these two classes which provide significant load reductions during periods when system load is highest. As Mr. Miller explains, this results in a higher allocation of production and transmission fixed costs then is appropriate. Therefore, he has proposed the use of the Modified A&E method.

return with annualized revenues. The next block shows the class rates of return and rate of return indices after all ratemaking adjustments, but prior to any revenue increase. It is important to note that there is no impact on the adjusted Net Operating Income, due to differences in fuel revenue and fuel expenses. Therefore, any revenue deficiency that needs to be addressed by the revenue requirement in this case is designed to impact non-fuel base rates. This portion of the exhibit is used as a guide in developing a methodology to distribute the base rate revenue increase among the classes.

For the purpose of apportioning the revenue increase to the customer classes, I have considered three of the four cost of service studies prepared by Company Witness Miller. These are (i) SWPA, (ii) SWPA for system to jurisdiction allocation and SWCP for allocation to the North Carolina customer classes, and (iv) SWPA for system to jurisdiction allocation and Modified A&E for allocation to the North Carolina customer classes.

Tables 1A, 1B, and 1C below summarize the results of the 2023 class cost of service studies using the three allocation methods I am considering in apportioning the revenue increase to the customer classes.

Table 1A
SWPA Cost Allocation to Jurisdictions and Customer Classes
Summary of 2023 Class Cost of Service Study

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS BEFORE REVENUE INCREASE

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$61,939,239	$39,281,392	$12,733,509	$5,132,276	$3,523,732	$1,191,949	$69,834	$6,547
Rate Base	$1,330,125,491	$696,222,134	$265,887,221	$145,058,094	$123,220,232	$64,825,046	$34,692,015	$220,750
ROR	4.6566%	5.6421%	4.7891%	3.5381%	2.8597%	1.8387%	0.2013%	2.9657%
Index	1.00	1.21	1.03	0.76	0.61	0.39	0.04	0.64

Table 1B
SWPA Cost Allocation to Jurisdictions and
SWCP Cost Allocation to Customer Classes
Summary of 2023 Class Cost of Service Study

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS BEFORE REVENUE INCREASE

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$61,939,240	$31,064,235	$12,424,838	$7,199,057	$8,842,687	$2,094,720	$306,136	$7,567
Rate Base	$1,330,125,491	$800,010,254	$269,769,715	$118,974,000	$56,020,257	$53,432,045	$31,711,691	$207,529
ROR	4.6566%	3.8830%	4.6057%	6.0510%	15.7848%	3.9203%	0.9654%	3.6462%
Index	1.00	0.83	0.99	1.30	3.39	0.84	0.21	0.78

Table 1C
SWPA Cost Allocation to Jurisdictions and
Modified A&E Cost Allocation to Customer Classes
Summary of 2023 Class Cost of Service Study

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS BEFORE REVENUE INCREASE

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$61,939,239	$38,944,088	$10,825,267	$5,916,538	$4,267,116	$2,075,789	($97,311)	$7,752
Rate Base	$1,330,125,491	$700,556,479	$289,958,358	$135,161,075	$113,769,794	$53,670,993	$36,803,653	$205,139
ROR	4.6566%	5.5590%	3.7334%	4.3774%	3.7507%	3.8676%	-0.2644%	3.7787%
Index	1.00	1.19	0.80	0.94	0.81	0.83	-0.06	0.81

As shown in the versions of Table 1 above, the different cost studies produce different results in terms of evaluating the reasonability of the Company's current rates for each customer class relative to their responsibility for costs. The three cost of service studies all have good reason for being considered in the course of apportioning the revenue increase to the classes in this proceeding. First, the SWPA is the cost allocation methodology approved by the Commission in the Company's 2019 rate case. In that rate case, the Company and CIGFUR reached a Stipulation of Partial Settlement that included a provision to consider the SWCP cost allocation methodology and cost of service study when apportioning the revenue change in the Company's next general rate case.[2] And finally, my understanding is that the Company has filed the A&E class factors and/or cost of service studies periodically in past general rate cases dating back to the early 1990's.

Q. Based on the result of these class costs of service studies, how does the Company propose to distribute the non-fuel base rate revenue requirement among the various customer classes?

A. As described above, the class cost of service study and resulting rates of return and rates of return indices in my Schedule 2 are being used as a guide in apportioning the non-fuel base rate revenue increase. After reviewing the class cost of service study information, placing more emphasis on the

[2] Docket No. E-22, Sub 562 Agreement and Stipulation of Partial Settlement between the Company and CIGFUR at Paragraph III.C. ("The Stipulating Parties agree that in its next general rate case, in addition to filing a class cost of service study based on the SWPA method weighted using the system load factor, the Company shall also file the results of a class cost of service study with production and transmission costs allocated on the basis of the Summer/Winter Coincident Peak method and consider such results for the sole purpose of apportionment of the change in revenue to the customer classes.")

modified A&E method, I then apply the following general and class-specific principles to equitably distribute the proposed base rate revenue changes:

- All customer classes should share in the non-fuel base rate revenue increase in a manner that moves each class of customers closer to parity with the North Carolina jurisdictional ROR.
- Generally, if a customer class has a ROR index less than 1.00, such class should receive a percentage increase that is greater than the overall jurisdiction percentage base rate increase. If a customer class has a ROR index greater than 1.00, such class should receive a percentage increase that is less than or equal to the overall jurisdiction percentage base rate increase.
- For those classes outside of a reasonable return index range of 0.90 and 1.10 ("Parity Index Range"), an effort must be made to more reasonably align the rates that customers pay with their responsibility for costs, even if the index achieved after apportionment remains outside of the Parity Index Range.
- For purposes of apportioning the increase to the LGS, 6VP, and NS classes, which include the Company's large non-residential customers including the largest industrial customers, in addition to the class rates of return and resulting indices, consideration is also given to the appropriate increase for these customer classes based upon certain non-cost factors as described below that support a

lesser increase for large industrial customers with high load factors within these classes.

- For the 6VP class, all customers take service under Schedule 6VP which provides both a day classification price signal (A, B, and C days with on / off-peak pricing) and up to 150 hours during the year when system load is the highest an additional price signal through a capacity surcharge rate in excess of 40 cents per kWh. The customers in the class respond to this strong price signal by reducing load during these hours when the capacity surcharge rate is in effect. Such load response benefits not only the specific customers in the 6VP class but all customers in the North Carolina jurisdiction.

- In addition, specifically for apportioning the increase to the NS class, I also balance the need to equitably address the unique nature of the Company's electric service arrangement with a very large and energy-intensive customer, Nucor, and how that arrangement benefits both the system and the customers in the North Carolina jurisdiction.

Q. Please elaborate on other non-cost factors that the Company has taken into account in apportioning the revenue requirement.

A. In apportioning the revenue increase to the LGS, 6VP, and NS classes, the Company has specifically considered several non-cost factors, including the quantity of its large industrial manufacturing customers' electric usage in their industrial operations and the time of that usage. In general, these types of customers may operate during all hours of the day, including weekends, in multiple shifts. Industrial customers that utilize their facilities and manufacturing operations around the clock often use a lot of energy relative to their maximum demand for electricity. These customers' loads typically vary less from one hour to the next over the course of the year than do other classes of customers.

For example, in terms of the NS class, the Company has an arrangement with Nucor that partially interrupts load during certain hours when the Company's system anticipates peak load conditions to occur. This partial interruption of Nucor's service benefits the system by reducing capacity that is needed to serve load. As discussed in the testimony of Company Witness Miller, the SWPA allocation method used in the cost of service that establishes the Company's requested revenue requirement recognizes the Nucor load during the hour of the system summer and winter peak. The loads during these two hours recognize that Nucor's load has been partially interrupted. This benefits the North Carolina jurisdiction and its customers by having a lower allocation of production and transmission demand plant and related costs that is used as a basis for establishing a revenue requirement.

In apportioning the revenue increase, I also consider factors such as factory utilization and the economic vitality of the Company's North Carolina service territory, as it relates to these industrial customers. High factory utilization (and increased employment) should be considered good indicators of the economic vitality of the region. In terms of employment, seven of the large high load factor industrial customers in the Company's LGS (three customers), Schedule 6VP (three customers), and Schedule NS classes employ thousands of people.

Q. Taking the foregoing guiding principles and other factors into account, please present the Company's proposed apportionment of the North Carolina jurisdictional cost of service to the customer classes.

A. The following tables present information on i) allocated rate base; ii) class rates of return and rates of return indices based upon the fully adjusted cost of service before apportioning the non-fuel base rate increase; iii) the apportionment of the non-fuel base rate increase; and iv) class rates of return and rates of return indices after apportionment.

TABLE 2A
SWPA Cost Allocation to Jurisdictions and Customer Classes

	NC Juris	Res	SGS / PA	LGS	NS	6VP	Out Lts	Traffic
Rate Base	$1,330,125,491	$696,222,134	$265,887,221	$145,058,094	$123,220,232	$64,825,046	$34,692,015	$220,750
% of Jurisdictional Rate Base	100.0%	52.3%	20.0%	10.9%	9.3%	4.9%	2.6%	0.0%
Fully Adjusted COS ROR	4.6566%	5.6421%	4.7891%	3.5381%	2.8597%	1.8387%	0.2013%	2.9657%
ROR Index Before Change	1.00	1.21	1.03	0.76	0.61	0.39	0.04	0.64
Non-fuel Increase - All Charges	$56,623,974	$29,876,494	$12,786,745	$5,455,296	$4,445,983	$2,012,965	$2,035,460	$11,031
ROR After Non-fuel Base Increase	7.6644%	8.6773%	8.1942%	6.1797%	5.3813%	4.0453%	4.4966%	6.5891%
ROR Index After Change	1.00	1.13	1.07	0.81	0.70	0.53	0.59	0.86

TABLE 2B

SWPA Cost Allocation to Jurisdictions and SWCP Cost Allocation to Customer Classes

	NC Juris	Res	SGS / PA	LGS	NS	6VP	Out Lts	Traffic
Rate Base	$1,330,125,491	$800,010,254	$269,769,715	$118,974,000	$56,020,257	$53,432,045	$31,711,691	$207,529
% of Jurisdictional Rate Base	100.0%	60.1%	20.3%	8.9%	4.2%	4.0%	2.4%	0.0%
Fully Adjusted COS ROR	4.6566%	3.8830%	4.6057%	6.0510%	15.7848%	3.9203%	0.9654%	3.6462%
ROR Index Before Change	1.00	0.83	0.99	1.30	3.39	0.84	0.21	0.78
Non-fuel Increase - All Charges	$56,623,974	$29,874,049	$12,786,653	$5,455,911	$4,447,566	$2,013,234	$2,035,531	$11,031
ROR After Non-fuel Base Increase	7.6644%	6.5473%	7.9651%	9.2044%	20.6022%	6.5425%	5.6580%	7.4938%
ROR Index After Change	1.00	0.85	1.04	1.20	2.69	0.85	0.74	0.98

TABLE 2C

SWPA Cost Allocation to Jurisdictions and Modified A&E Cost Allocation to Customer Classes

	NC Juris	Res	SGS / PA	LGS	NS	6VP	Out Lts	Traffic
Rate Base	$1,330,125,491	$700,556,479	$289,958,358	$135,161,075	$113,769,794	$53,670,993	$36,803,653	$205,139
% of Jurisdictional Rate Base	100.0%	52.7%	21.8%	10.2%	8.6%	4.0%	2.8%	0.0%
Fully Adjusted COS ROR	4.6566%	5.5590%	3.7334%	4.3774%	3.7507%	3.8676%	-0.2644%	3.7787%
ROR Index Before Change	1.00	1.19	0.80	0.94	0.81	0.83	-0.06	0.81
Non-fuel Increase - All Charges	$56,623,974	$29,876,393	$12,786,177	$5,455,529	$4,446,205	$2,013,228	$2,035,411	$11,031
ROR After Non-fuel Base Increase	7.6644%	8.5767%	6.8736%	7.1922%	6.4546%	6.4794%	3.7882%	7.6699%
ROR Index After Change	1.00	1.12	0.90	0.94	0.84	0.85	0.49	1.00

Q. What allocation method did the Company utilize to apportion the revenue requirement to the North Carolina jurisdictional customer classes?

A. As noted above, I considered three of the four class cost of service studies presented by Company Witness Miller. The results described below are based on the utilization of the modified A&E cost of service study shown on Table 2C above and Company Witness Miller's Schedule 26.

Q. Please explain the Company's apportionment of the North Carolina jurisdictional non-fuel base rate increase to the residential class.

A. As shown in Table 2, the North Carolina jurisdictional rate of return including the $56.624 million proposed revenue increase is 7.6644% which reflects the jurisdictional rate of return index of 1.0. In terms of cost responsibility for rate base, the residential class is the largest with an allocation of $700.6 million or 52.7% of the jurisdictional total rate base. The class ROR on this allocated rate base is 5.5590% with an index of 1.19 before any apportionment of the non-fuel base rate increase and is above the desired Parity Index Range of 0.90 to 1.10. The large size of this class in terms of responsibility for rate base and related expenses, means that it will be responsible for the greatest portion of the non-fuel base rate increase, with a target percentage increase of 21.38% (jurisdictional increase is 22.50%). The index after the increase of 1.12 shows that the residential class will have rates that help move the class closer to the Parity Index Range.

Q. Please explain the Company's apportionment of the North Carolina jurisdictional non-fuel base rate increase to the SGS and Public Authority class.

A. As shown in Table 2, the SGS and Public Authority class is the second largest in the jurisdiction with an allocation of almost $290.0 million or 21.8% of the jurisdictional total rate base. The class ROR on this allocated rate base is 3.7334% with an index of 0.80 before any apportionment of the non-fuel base rate increase. This class is large in terms of cost responsibility for rate base and related expenses, and it will bear responsibility for the second highest portion of the non-fuel base rate increase. To more reasonably align rates with responsibility for cost, I have apportioned a target percentage increase in non-fuel base revenue for this class of 25.8%, which is more than the non-fuel base percentage increase for the jurisdiction of 22.5%. While the Company is endeavoring through this apportionment to bring this class toward the Parity Index Range, the index after the apportionment increase moves from 0.80 to 0.90 and reflects that the class will still pay rates that are below cost, and this class's ROR is just at the lower end of the desired Parity Index Range.

Q. Please explain the Company's apportionment of the North Carolina jurisdictional non-fuel base rate increase to the LGS and the 6VP classes.

A. The LGS class is composed of large general service customers with some classified as commercial/public authority and others classified as industrial. There is a wide range of customers in this class in terms of size and operations, factors that impact these customers' quantity consumed and manner of use of electric service. This class includes large retail stores, grocery stores, colleges, health care facilities, governmental facilities, and industrial manufacturers - both small and large. As shown in Table 2, this is the third largest class with an allocation of rate base of $135.2 million or approximately 10.2% of the jurisdictional rate base. Its ROR is 4.3774% resulting in an index of 0.94. This class is currently within the Parity Index Range and remains so after its proposed revenue increase.

The 6VP class is composed of large industrial customers engaged in manufacturing. As shown in Table 2, this class has been allocated responsibility for $113.8 million or about 8.6% of the jurisdictional rate base. Its ROR is 3.7507% resulting in an index of 0.81.

Both the LGS and 6VP classes have a ROR that is below the desired Parity Index Range. Taking this into account and considering the nature of these customers' usage, as well as concerns about the economic competitiveness of industrial customers and maintaining the economic vitality of the Company's North Carolina service territory, I have apportioned a target percentage increase less than the jurisdictional target increase. The apportioned increase results in an improved ROR index of 0.84 for the 6VP class.

Q. Please explain the Company's apportionment of the North Carolina jurisdictional non-fuel base rate increase to the NS class.

A. As shown in Table 1, Nucor has been allocated responsibility for $53.7 million or 4.0% of jurisdictional rate base. The fully adjusted cost of service shows that the Schedule NS class has a ROR of 3.8676% with an index of 0.83.

With an ROR Index of 0.83 and considering the operational benefit to the system and the benefit in cost allocation because of the partially interruptible nature of service to Nucor, I believe that the apportionment of the non-fuel revenue to this important large industrial customer should move it closer to an index that is approximately 10 basis points below the Parity Index Range, consistent with the apportionment proposed and approved in the 2019 proceeding. Therefore, I have apportioned a target percentage increase in non-fuel base rate revenue for the NS class to bring it closer to the Parity Index Range with an index of 0.85%.

Q. Is the Company taking any other steps to work with Nucor regarding its existing service under Schedule NS?

A. Yes. The current agreement underlying Schedule NS expires December 31, 2025. The Company continuously works with Nucor regarding the renewal and/or amendment of its agreement. The Company has developed its allocation and rate design proposals based upon the assumption of continued service, inclusive of the requested base rate increase, under current Schedule NS and the existing Nucor agreement.

Q. Finally, please explain the Company's apportionment of the North Carolina jurisdictional non-fuel base rate increase to the Outdoor / Street Lighting and Traffic Lights classes.

A. As shown in Table 2, the Outdoor/Street Lighting and Traffic Lights classes are the two smallest customer classes in terms of responsibility for rate base. The ROR before the non-fuel base rate increase for the Outdoor/Street Lighting class is 3.7787% with an index of 0.81. The proposed increase to the Outdoor/Street Lighting class brings the class to parity with an index of 1.10. The ROR for the Traffic Lighting class is -0.2644% with an index of -0.06, which is significantly below the Parity Index Range. The rates the Traffic Lighting class is currently paying are not reasonably aligned with cost.

Therefore, effort is being made to apportion more than the jurisdictional percentage increase to this class to begin bringing rates in line with cost responsibility. After the apportioned increase of 39.4%, the Traffic Lights class has an index of 0.49, still significantly below the Parity Index Range.

Q. Do you have any concluding comments regarding DENC's proposed apportionment of the base non-fuel rate increase among the customer classes?

A. Yes. The resulting non-fuel base rate revenue target increases are shown on Page 4 of my Schedule 2. The last section on Page 4 of my Schedule 2 shows the class rates of return and indices after accounting for all ratemaking adjustments, including the base rate revenue increases, as just described.

It should be noted that these percentage increases are not "total bill" percentage increases, rather the increases represent an apportionment percentage applied only to the non-fuel base component of the rate structure for each customer class. As I describe in Section III below, while the Company's customer classes will experience an increase in non-fuel base rates, their total bill will be substantially moderated when the proposed projected fuel components of DENC's rate structure are taken into consideration as discussed more in the testimonies of Company Witness Christopher C. Hewett and Company Witness Jeffrey D. Matzen.

II B. PROPOSED RATE DESIGN

Q. Given the apportionment of the non-fuel base rate increase to the customer classes and the target percentage increases that you have just described, please now describe how the components of the rate schedules are adjusted to achieve these non-fuel base rate increases.

A. Form E-1 Item 39 Part C provides a page for each rate schedule that shows the annualized revenue calculated based on current rates applied to the 2023 billing determinants as of December 31, 2023. This calculation is by each rate component or "block" in the rate schedule. For purposes of reference, the rates placed in effect November 1, 2019 as a result of the 2019 Rate Case in Docket No. E-22, Sub 562 are considered the "present rates." The revenue based on these present rates is considered the "present revenue."

Next, the target percentage increase for each customer class is applied to the total present revenue to calculate the target revenue increase for the rate schedule. Next, a factor to adjust each rate component is developed. The factor is then applied to each present rate component to calculate the proposed rate. Proposed revenue by rate component is calculated by multiplying the proposed rate times the billing determinant. The proposed revenue is summed and compared to the present revenue. The final change in revenue is calculated in a similar manner for each rate schedule.

The final proposed revenue and the final change in revenue is reported on the summary sheet shown in Form E-1 Item 42a. The proposed base non-fuel revenue or basic revenue is specifically shown in Column 7 and the proposed change in such revenue is shown in Column 11. As will be discussed later, this final summary sheet is also presented in my testimony Schedule 3. In total, the final change in revenue equals the revenue increase of $56.624 million proposed by Company Witness McLeod.

Q. For each rate schedule, does the final change in revenue for each function exactly equal the proposed target revenue increase?

A. No. There are minor differences between the target revenue increase and the final change in revenue due to rounding. Also, due to the need to match the total revenue requirement increase for the jurisdiction, certain rate components may have been adjusted by very small amounts.

Q. Has the Company considered the unit cost study prepared by Company Witness Miller and provided in Form E-1, Item 45e during the development of rates?

A. Yes. I reviewed the study and noted the fully supported customer charges for the customer classes. I analyzed the differences in the current basic customer charge compared to the fully supported unit customer cost as provided by Company Witness Miller for each customer class. The Company's goal was to move the basic customer charge closer to the fully supported unit cost based on the current relationship of each rate schedule's basic customer cost and the unit customer cost for the class. For residential Schedule 1 customers, the Company proposes increasing the basic customer charge from $10.67 to $14.54. This approach to the rate design of the customer charges generally produces a proposed customer charge that is less than the fully supported customer charges prepared by Company Witness Miller in Form E-1, Item 45e. There may be exceptions for a limited number of rate schedules in certain classes that require metering arrangements that are more costly in order to properly bill the rate schedule determinants than the metering required for standard rate schedules in the class.

III. SUMMARY SHEET AND TYPICAL BILLS

Q. Do you provide a schedule showing the non-fuel base rate revenue amount and percent change by rate schedule associated with the non-fuel base rate revenue increase?

A. Yes. My Schedule 3, Column 19 shows the increase in the non-fuel base rate revenues by rate schedule. Column 27 shows the percent change in non-fuel base rate revenue compared to existing non-fuel base rate revenues. Column 34 shows the percent change in total revenue (*i.e.* non-fuel base rate revenue plus rider revenue, fuel revenue associated with the Placeholder Base Fuel Rate as discussed in the direct testimony of Company Witness Hewett, and the currently approved EMF, also discussed in the testimony of Company Witness Hewett).

Q. What is the effective date of the changes that the Company proposes to make to the rate schedules?

A. The Company proposes that the changes to the rate schedules become effective for usage on and after May 1, 2024, which is at least 30 days after the filing date of the tariffs in this proceeding, with the expectation that the Commission will suspend these rates pursuant to N.C. Gen. Stat. § 62-134.

Q. Mr. Givens, assuming the proposed change in non-fuel base rates, combined with the Placeholder Base Fuel Rate and the existing EMF, become effective May 1, 2024, how will those changes impact the average monthly bills of typical residential, small general service, and large general service customers?

A. The effect of the proposed non-fuel base rate increase, to become effective for usage on and after May 1, 2024, when combined with the Placeholder Base Fuel Rate, the currently approved Fuel Rider B – Experience Modification Factor, and the currently approved Fuel Rider B1 as presented by Company Witness Hewett, is listed below for each of the following typical average monthly bills:

- For Rate Schedule 1 (residential), assuming a customer that uses 1,000 kWh per month, the weighted average monthly residential bill (four months on summer rates and eight months on base or non-summer rates) would increase from $133.11 to $152.18, or by 14.33%;
- For Rate Schedule 5 (small general service), assuming a customer that uses 12,500 kWh per month and 50 kW or demand, the weighted average monthly small general service bill (four months on summer rates and eight months on base or non-summer rates) would increase from $1,353.47 to $1,560.89, or by 15.33%;

- For Rate Schedule 6P (large general service), assuming a customer that uses 576,000 kWh (259,200 on-peak kWh and 316,800 off-peak kWh) per month and 1,000 kW of demand, the weighted average monthly large general service bill (four months on summer rates and eight months on base or non-summer rates) would decrease from $50,834.49 to $56,249.26, or by 10.65%; and
- For Rate Schedule 6L (large general service), assuming a customer that uses 6,000,000 kWh (2,400,000 on-peak kWh and 3,600,000 off-peak kWh) per month and 10,000 kW of demand, the weighted average monthly large general service bill (four months on summer rates and eight months on base or non-summer rates) would decrease from $485,897.78 to $535,142.74, or by 10.13%.

Q. Do you anticipate the foregoing increase in the Company's non-fuel base rates will be allowed to become effective on May 1, 2024, as proposed?

A. No. Consistent with previous North Carolina base rate case proceedings, the Company anticipates that the Commission will suspend the non-fuel base rates proposed in the Company's Application to become effective on May 1, 2024. This suspension, and the timing of the effective date of new rates on February 1, 2025, is important, as it allows DENC to generally synchronize the adjustment to non-fuel base rates with the Company's 2024 fuel factor during the early part of 2025. As supported in my Schedule 3, the overall effect of the proposed non-fuel base rate increase, current non-fuel riders, combined with the projected fuel rate reduction to be filed in August 2024, is listed below for each of the following typical average monthly bills:

- For Rate Schedule 1 (residential), assuming a customer that uses 1,000 kWh per month, the weighted average monthly residential bill (four months on summer rates and eight months on base or non-summer rates) would decrease from $133.11 to $128.93, or by 3.14%;
- For Rate Schedule 5 (small general service), assuming a customer that uses 12,500 kWh per month and 50 kW or demand, the weighted average monthly small general service bill (four months on summer rates and eight months on base or non-summer rates) would decrease from $1,353.46 to $1,270.59, or by 6.12%;
- For Rate Schedule 6P (large general service), assuming a customer that uses 576,000 kWh (259,200 on-peak kWh and 316,800 off-peak kWh) per month and 1,000 kW of demand, the weighted average monthly large general service bill (four months on summer rates and eight months on base or non-summer rates) would decrease from $50,834.49 to $42,988.59, or by 15.43%; and
- For Rate Schedule 6L (large general service), assuming a customer that uses 6,000,000 kWh (2,400,000 on-peak kWh and 3,600,000 off-peak kWh) per month and 10,000 kW of demand, the weighted average monthly large general service bill (four months on summer rates and eight months on base or non-summer rates) would decrease from $485,897.78 to $397,010.74, or by 18.29%.

IV. RATE SCHEDULES

Q. Is the Company filing proposed rate schedules that will be changed to collect the proposed revenue requirement of $56.624 million?

A. Yes. The rate schedules that the Company proposes to become effective for usage on and after May 1, 2024, to be used in collecting the proposed $56.624 million revenue requirement, are presented as Item 39 of the Company's Form E-1. The current rates to be changed in those May 1, 2024 rate schedules are struck through and the new proposed rates added are shown in italics.

Q. When is the Company requesting to place permanent base rates into effect, upon Commission approval?

A. As noted in the testimony of Company Witness Hewett, the fuel rates proposed in the Company's upcoming August 2024 annual fuel factor proceeding will go into effect on February 1, 2025, with Commission approval. There are synergies produced by implementing the proposed base rates (included in the May 1, 2024, rate schedules) in this proceeding as close as possible to the August 2024 Base Fuel Rate (which would update and replace the Placeholder Base Fuel Rate). As noted in the Company's Application in this proceeding, the Company requests the Commission issue an Order(s) that will allow the Company to put these final rates into effect for usage on and after February 1, 2025, on a permanent basis.[3]

[3] This would be one month prior to the projected reduction in the fuel rate, which will take effect on February 1, 2025.

Q. Is the Company considering putting the non-fuel base rate increase into effect on a temporary basis?

A. Yes. Consistent with prior North Carolina base rate case proceedings, the Company intends to accelerate implementing base rates for usage on and after November 1, 2024, on a temporary basis, subject to refund, pursuant to N.C. Gen. Stat. § 62-135. Prior to implementing temporary rates, the Company will submit a proposal to the Commission to refund any over-recoveries received under temporary rates, plus interest, as well as obtain any approvals required by N.C. Gen. Stat. § 62-135, consistent with the approach followed in the 2019 Rate Case.

V. NEW EXPERIMENTAL SMALL GENERAL SERVICE RATE SCHEDULE TO INCENTIVIZE THIRD PARTY INVESTMENT IN EV CHARGING

Q. Why is the Company proposing a new SGS rate in its North Carolina jurisdiction?

A. After discussions with the Company's Electrification group, the Customer Rates department was asked about the possibility of designing a small general service rate to help incentivize and promote third party development and investment in EV charging in the Company's North Carolina jurisdiction.

In response to this interest, the Company has developed and is proposing a new experimental small general service EV Charging rate. The Company proposes that this experimental rate be limited to 25 customers over an approximately four-year period, beginning February 1, 2025 and ending on

December 31, 2028.

Q. Can you describe the structure and the design of this new experimental SGS rate?

A. Yes. The Company is proposing a rate schedule similar to the structure of Schedule GS-2 in the Company's Virginia jurisdiction. Schedule GS-2 includes both non-demand billing and demand billing. The non-demand billing charges include a customer charge and an energy charge for customers whose usage does not exceed 200 kWh per kW of demand per month. The demand billing charges include a customer charge, an energy charge, and a demand charge for customers whose usage exceeds 200 kWh per month.

The Company has designed this experimental rate to be revenue neutral with annualized base revenues for Schedule 5, and Schedule 30 customers.

Q. Please describe the applicability provisions of the proposed experimental small general service Schedule SGS-EV.

A. The applicability provisions are set forth in the proposed tariff sheet as presented in my Schedule SGS-EV.

Q. Why did the Company propose that this experimental SGS rate include both a demand and non-demand billing structure?

A. Rate Schedule SGS-EV includes both a non-demand billing component and a demand billing component to encourage customers to deploy third-party EV charging to owners and operators of electric vehicles during these early stages when utilization of this technology may be low. A non-residential rate schedule that only has a demand billing component to recover the cost of service would potentially be punitive to customers that provide this EV charging service (EV Charging Provider) because there is not yet a sufficient scale of regular usage of EV charging facilities. In other words, because there is likely to be a low utilization of third party EV charging during the initial deployment of public commercial charging facilities, recovering the costs of electric utility service through a demand charge may not allow the Company's customer (EV Charging Provider) to match the charges for its provision of EV charging service to electric vehicle owners and operators to the costs of electric utility service from the Company.

By providing a non-demand charge billing component in the proposed Schedule SGS-EV tariff for usage up to 200 kWh per kW (200 hours use), the Company will be billing its customer (EV Charging Provider) based on a two-part rate design consisting of a customer charge and energy charges for usage up to 200 hours use per kW of demand placed upon the system. This will allow the EV Charging Providers who have low utilization of their charging facilities by owners and operators of electric vehicles to better be able to "match" the billed costs of electric utility service with charges to its end-use customers.

Q. Did the Company prepare a customer bill impact comparison with this new SGS-EV rate compared to the proposed Schedule 5 rates?

A. Yes, the results of this bill comparison between the proposed experimental rate SGS-EV as compared to the proposed Schedule 5 rates is shown in Table

3 below.

Table 3

TYPICAL BILL SUMMARY

TOTAL PROPOSED BILL COMPARISON

NEW SGS-EV to NC SCHEDULE 5

KW	KWH	Load Factor	SCH 5	SGS-EV	DIFFERENCE	% DIFF
30	4,500	21%	$612.38	$603.97	($8.41)	-1.37%
30	5,400	25%	$729.51	$719.55	($9.96)	-1.37%
30	6,264	29%	$841.94	$967.70	$125.76	14.94%
30	7,560	35%	$995.78	$1,076.72	$80.94	8.13%
30	9,000	42%	$1,145.09	$1,197.84	$52.75	4.61%
30	10,800	50%	$1,331.72	$1,339.02	$7.30	0.55%
30	11,880	55%	$1,443.69	$1,423.73	($19.96)	-1.38%
30	13,608	63%	$1,622.86	$1,558.23	($64.63)	-3.98%
30	15,000	69%	$1,767.20	$1,654.22	($112.98)	-6.39%
50	7,500	21%	$1,002.79	$989.24	($13.55)	-1.35%
50	9,000	25%	$1,198.00	$1,181.88	($16.12)	-1.35%
50	10,440	29%	$1,347.30	$1,595.48	$248.18	18.42%
50	12,600	35%	$1,571.25	$1,777.16	$205.91	13.10%
50	15,000	42%	$1,820.10	$1,979.04	$158.94	8.73%
50	18,000	50%	$2,131.15	$2,214.34	$83.19	3.90%
50	19,800	55%	$2,317.78	$2,355.52	$37.74	1.63%
50		63%	$2,616.39	$2,579.70	($36.69)	-1.40%

	22,680					
50	25,000	69%	$2,856.94	$2,739.67	($117.27)	-4.10%
100	15,000	21%	$1,952.37	$1,952.43	$0.06	0.00%
100	18,000	25%	$2,263.42	$2,337.70	$74.28	3.28%
100	20,880	29%	$2,562.02	$3,164.88	$602.86	23.53%
100	25,200	35%	$3,009.94	$3,528.26	$518.32	17.22%
100	30,000	42%	$3,507.61	$3,932.01	$424.40	12.10%
100	36,000	50%	$4,129.72	$4,402.62	$272.90	6.61%
100	39,600	55%	$4,502.97	$4,684.98	$182.01	4.04%
100	45,360	63%	$5,100.19	$5,133.35	$33.16	0.65%
100	50,000	69%	$5,581.28	$5,453.28	($128.00)	-2.29%
150	22,500	21%	$3,080.81	$2,915.60	($165.21)	-5.36%
150	27,000	25%	$3,547.38	$3,493.51	($53.87)	-1.52%
150	31,320	29%	$3,995.29	$4,734.30	$739.01	18.50%
150	37,800	35%	$4,667.16	$5,279.36	$612.20	13.12%
150	45,000	42%	$5,413.69	$5,884.99	$471.30	8.71%
150	54,000	50%	$6,346.83	$6,590.89	$244.06	3.85%
150	59,400	55%	$6,906.72	$7,014.44	$107.72	1.56%
150	68,040	63%	$7,802.55	$7,686.99	($115.56)	-1.48%
150	75,000	69%	$8,524.19	$8,166.89	($357.30)	-4.19%
250		21%	$5,337.69	$4,841.96	($495.73)	-9.29%

	37,500					
250	45,000	25%	$6,115.32	$5,805.15	($310.17)	-5.07%
250	52,200	29%	$6,861.83	$7,873.13	$1,011.30	14.74%
250	63,000	35%	$7,981.61	$8,781.56	$799.95	10.02%
250	75,000	42%	$9,225.82	$9,790.93	$565.11	6.13%
250	90,000	50%	$10,781.06	$10,967.44	$186.38	1.73%
250	99,000	55%	$11,714.21	$11,673.34	($40.87)	-0.35%
250	113,400	63%	$13,207.25	$12,794.25	($413.00)	-3.13%
250	125,000	69%	$14,409.99	$13,594.09	($815.90)	-5.66%
450	67,500	21%	$9,851.45	$8,694.68	($1,156.77)	-11.74%
450	81,000	25%	$11,251.18	$10,428.41	($822.77)	-7.31%
450	93,960	29%	$12,594.91	$14,150.78	$1,555.87	12.35%
450	113,400	35%	$14,610.52	$15,785.96	$1,175.44	8.05%
450	135,000	42%	$16,850.09	$17,602.83	$752.74	4.47%
450	162,000	50%	$19,649.53	$19,720.54	$71.01	0.36%
450	178,200	55%	$21,329.20	$20,991.18	($338.02)	-1.58%
450	204,120	63%	$24,016.67	$23,008.82	($1,007.85)	-4.20%
450	225,000	69%	$26,181.59	$24,448.52	($1,733.07)	-6.62%

VI. TERMS AND CONDITIONS AND EXISTING RIDERS

Q. Does the Company propose to make any changes to its filed Terms and Conditions for service?

A. Yes. Item 39 of the Company's Form E-1 shows, among other things and through strikethroughs and italics, the changes the Company proposes to make to each section of the Terms and Conditions, and Rider D – Tax Effect Recovery Factor. The Company proposes changes to several miscellaneous service fees to cover the updated cost of service, excess facilities charge percentages, as well as minor wording changes. In addition, as noted in the direct testimony of Company Witness Jerri A. Brooks, the Company is also proposing changes for the Terms and Conditions Section XXII related to the Company's Line Extension Plan. Accompanying each revised section of the Terms and Conditions is a "Comments" page(s) that provides a brief description of each proposed change. The Company proposes an effective date of May 1, 2024, for the Terms and Conditions changes. However, the Company proposes to wait to implement the Terms and Conditions changes until permanent rates become effective and changes are approved by the Commission.

Q. Can you provide a list of the charges that the Company proposes to update in the Terms and Conditions?

A. My Schedule 6, page 1 contains a list of the charges being updated based upon the costs of providing such services.

VII. RULE R1-17 AND FORM E-1 REQUIREMENTS

Q. You mentioned earlier that you are sponsoring Appendix 1, Exhibit I, and Exhibit II, as required by Rule R1-17. Please describe each of these documents that you are sponsoring.

A. Appendix 1 or "Effect of Proposed Increase," as required by Rule R1-17(b)(9)f, includes two summary sheets showing the effect of the proposed increase, by customer class and by rate schedule. Summary sheet 1 presents the impact of proposed changes to non-fuel base rates, the Placeholder Base Fuel Rate and the existing EMF. Summary sheet 2 presents the impact of proposed changes to the non-fuel base rates, the Projected Base Fuel Rate and projected EMF.

Exhibit I or "Present Charges," as required by Rule R1-17(b)(1) shows the Company's rates or other charges presently in effect that the Company is proposing to change.

Exhibit II or "Proposed Charges," as required by Rule R1-17(b)(2) shows the Company's proposed rates or other charges which the Company seeks to place in effect.

Q. Regarding the Company's Form E-1, you are also sponsoring Items 39 a. – c., 40, and 42 a. – c. What information is required in each of these Items?

A. The requirements for these Items are described below:

<u>Item 39</u>

A statement, showing by strikethroughs and italicized inserts, all new rates and proposed changes in rates, charges, and Terms and Conditions, as well as percentage increases (decreases) for each rate or charge.

a. Includes summary statements of the new rates and proposed changes and reasons for each change.

b. Includes all new rates, charges, Terms and Conditions, as well as changes to existing rates, charges, and Terms and Conditions.

c. Includes workpapers showing derivation of the rates by rate schedule.

Item 40

An estimate of marginal costs (customer, demand, and energy) for each of the Company's rate schedules whenever marginal costs are used in the rate design for any rate schedule.

Item 42

a. If not included in Item 45, provides test year revenues from the sale of electricity for each of the Company's North Carolina Retail rate schedules based on 1) per books revenues, 2) present annualized rates, and 3) proposed annualized rates.

b. If not shown separately in item 45, shows the test year operating revenues from sources other than sales of electricity based on 1) per books revenues, 2) present annualized rates, and 3) proposed annualized rates.

c. Provides the detailed workpapers showing the calculation of revenues for each of the Company's North Carolina retail rate schedules as presented in Items 42 a. and 42 b., above. The number of billing units used in the calculations, such as the kWh usage or the kilowatt billing demand, as appropriate, is shown in each rate block.

Q. Earlier in your testimony, you mentioned that you were sponsoring adjustments associated with customer growth, increased usage, and weather normalization. Where are these adjustments included?

A. The adjustments for customer growth, increased usage, and weather normalization are incorporated in Form E-1 Item 42.a. The methodologies used to calculate these adjustments are consistent with those approved by the Commission in the 2019 Rate Case.

Q. Will you be making an adjustment in the Company's August supplemental filing to account through non-fuel base rates for kWh sales reductions and associated lost revenues resulting from customer participation in DENC's North Carolina energy efficiency ("EE") programs?

A. Yes. The Company currently offers a portfolio of Commission-approved EE programs to its North Carolina customers. As provided for in the operative Cost Recovery and Incentive Mechanism ("Mechanism") agreed to between the Company and the Public Staff and approved by the Commission on May 22, 2022,[4] the kWh sales reductions resulting from customer participation in DENC's North Carolina EE programs may be used in the calculation of a lost revenues incentive for a period equal to the earlier of a) 36 months from the

[4] *Order Approving Revised Cost Recovery and Incentive Mechanism And Granting Waiver*, Docket No. E-22, Sub 464 (May 22, 2022).

installation of the measures, or b) as of the effective date of an alternative recovery mechanism or new approved non-fuel base rates that are set in a general rate case to recover lost revenues associated with the kWh sales reductions. Consistent with the Company's approach in the 2019 Rate Case, the Company will make an adjustment in its August 2024 supplemental filing to "recognize" the kWh sales reductions associated with measures installed through June 30, 2024, as being recovered through the non-fuel base rates. The Company anticipates supporting this adjustment using its most current Evaluation, Measurement, and Verification Report.

Q. Mr. Givens, does this conclude your direct testimony?

A. Yes.

APPENDIX A

BACKGROUND AND QUALIFICATIONS
OF
C. ALAN GIVENS

C. Alan Givens graduated from Radford University with a Bachelor of Science degree in Business Finance. Mr. Givens is a Certified Public Accountant and a member of both the American Institute of Certified Public Accountants and the Virginia Society of Certified Public Accountants. Prior to joining the Company in December 2003, he had over ten years of experience in auditing and accounting. Mr. Givens has held numerous accounting positions within the Company prior to joining the Regulatory Accounting Department in December 2007. He worked in Regulatory Accounting until June 1, 2022, when Mr. Givens became Manager – Regulation Rate Design. His responsibilities include providing support and analysis for the Company's regulatory filings in Virginia and North Carolina.

Mr. Givens has previously provided testimony before the State Corporation Commission of Virginia and the North Carolina Utilities Commission.

DOMINION ENERGY NORTH CAROLINA
ALLOCATION OF PROPOSED REVENUE INCREASE
12 MONTHS ENDED DECEMBER 31, 2023 - ADJUSTED FOR INCREASED USAGE, WEATHER, AND CUSTOMER GROWTH & EE
DOCKET NO. E-22, SUB 694

BASE NON-FUEL | **BASE FUEL**

1	PROPOSED BASE NON-FUEL RATE INCREASE	$56,623,974	
2	LESS: CHANGE IN LATE PAYMENT REVENUE	$94,521	MISC. REVENUES
3	CHANGE IN LOAD MGT CREDITS	$0	
4	CHANGE IN CONTRACT DOLLAR AMOUNT	$0	
5	CHANGE IN MISC SERVICE REVENUE	($353,568)	
6	CHANGE IN FACILITIES CHARGES	($73,600)	
7	PROPOSED REVENUE CHANGE TO RATE SCHEDULES AND RIDER EDR	$56,956,621	
8	PROPOSED CHANGE TO RIDER EDR	($4,826)	
9	PROPOSED CHANGE TO RATE SCHEDULES	$56,961,447	
10	PRESENT RIDER EDR REVENUE	($37,798)	
11	PRESENT BASE NON-FUEL REVENUE	$253,168,781	
12	SUM OF PRESENT BASE NON-FUEL REV & RIDER EDR REV	$253,130,983	
13	OVERALL BASE NON-FUEL REVENUE PERCENTAGE INCREASE	22.5028%	

	A. CALCULATION OF PROPOSED CLASS PERCENTAGES	PRESENT BASE NON-FUEL RATE SCHEDULE REVENUE INCL. GROWTH THROUGH 06/30/2024	INCREASE IN BASE NON-FUEL REVENUE	CHANGE IN LATE PAYMENT, LOAD MGT CREDITS MISC. SER. CHG., AND FACILITIES CHG REVENUE	INCREASE IN BASE NON-FUEL RATE SCHEDULE REVENUE	TARGET BASE NON-FUEL RATE SCHEDULE PERCENT INCREASE	TARGET PERCENT INCREASE/ OVERALL BASE NON-FUEL PERCENT INCREASE	PRESENT BASE FUEL AND RIDER A REVENUE	PROPOSED BASE FUEL AND RIDER A REVENUE	CHANGE IN BASE FUEL AND RIDER A REVENUE	PERCENTAGE CHANGE IN BASE FUEL AND RIDER A REVENUE
14	RESIDENTIAL	$140,543,919	$29,880,418	($164,524)	$30,044,942	21.3776%	95.00%	$56,588,061	$56,588,061	$0	0.0000%
15	SMALL GENERAL SERVICE & PUBLIC AUTH	$50,282,973	$12,786,668	($186,786)	$12,973,454	25.8009%	114.66%	$26,591,644	$26,591,644	$0	0.0000%
16	LARGE GENERAL SERVICE	$25,192,890	$5,456,162	$42,177	$5,413,985	21.4901%	95.50%	$19,283,367	$19,283,367	$0	0.0000%
17	6VP	$9,824,655	$2,012,662	$22,926	$1,989,736	20.2525%	90.00%	$8,922,606	$8,922,606	$0	0.0000%
18	SCHEDULE NS	$22,022,655	$4,445,965	($14,169)	$4,460,134	20.2525%	90.00%	$24,569,249	$24,569,249	$0	0.0000%
19	TRAFFIC	$50,962	$11,032	($436)	$11,468	22.5028%	100.00%	$17,939	$17,939	$0	0.0000%
20	OUTDOOR & STREET LIGHTS	$5,250,727	$2,035,892	($31,835)	$2,067,727	39.3798%	175.00%	$686,720	$686,720	$0	0.0000%
21	BASE NON-FUEL REVENUE	$253,168,781	$56,628,800	($332,647)	$56,961,447	22.4994%		$136,659,587	$136,659,587	$0	0.0000%
22	RIDER EDR REVENUE	($37,798)	($4,826)	$0	($4,826)	12.7672%					
23	BASE NON-FUEL RATE SCHEDULE REV + RIDER EDR REV	$253,130,983			$56,956,621						

	B. TOTAL PROPOSED BASE NON-FUEL REVENUES EXCLUDES ALL FUEL, NON-FUEL RIDERS, MISC REVENUE	NORTH CAROLINA JURISDICTIONAL	RESIDENTIAL	SGS & PUBLIC AUTH	LGS	6VP	NS	TRAFFIC	OUTDOOR & ST LIGHTS
24	PRESENT BASE NON-FUEL REVENUE	$253,168,781	$140,543,919	$50,282,973	$25,192,890	$9,824,655	$22,022,655	$50,962	$5,250,727
25	PROPOSED BASE NON-FUEL REVENUE	$310,130,227	$170,588,860	$63,256,427	$30,606,875	$11,814,392	$26,482,789	$62,430	$7,318,455
26	CHANGE	$56,961,447	$30,044,942	$12,973,454	$5,413,985	$1,989,736	$4,460,134	$11,468	$2,067,727
27	% CHANGE	**22.4994%**	**21.3776%**	**25.8009%**	**21.4901%**	**20.2525%**	**20.2525%**	**22.5028%**	**39.3798%**

	C. TOTAL PROPOSED BASE FUEL REVENUES	NORTH CAROLINA JURISDICTIONAL	RESIDENTIAL	SGS & PUBLIC AUTH	LGS	6VP	NS	TRAFFIC	OUTDOOR & ST LIGHTS
28	PRESENT BASE FUEL REVENUE + PRESENT RIDER A REVENUE	$136,659,587	$56,588,061	$26,591,644	$19,283,367	$8,922,606	$24,569,249	$17,939	$686,720
29	PROPOSED BASE FUEL REVENUE (PROPOSED RIDER A $0)	$136,659,587	$56,588,061	$26,591,644	$19,283,367	$8,922,606	$24,569,249	$17,939	$686,720
30	CHANGE	$0	$0	$0	$0	$0	$0	$0	$0
31	% CHANGE	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**

	D. TOTAL PROPOSED BASE REVENUES EXCLUDING MISCELLANEOUS REVENUES	NORTH CAROLINA JURISDICTIONAL	RESIDENTIAL	SGS & PUBLIC AUTH	LGS	6VP	NS	TRAFFIC	OUTDOOR & ST LIGHTS
32	PRESENT BASE NON FUEL AND BASE FUEL REVENUE	$389,828,367	$197,131,979	$76,874,616	$44,476,257	$18,747,262	$46,591,905	$68,901	$5,937,448
33	PROPOSED BASE NON FUEL AND BASE FUEL REVENUE	$446,789,814	$227,176,921	$89,848,071	$49,890,242	$20,736,998	$51,052,039	$80,369	$8,005,175
34	CHANGE	$56,961,447	$30,044,942	$12,973,454	$5,413,985	$1,989,736	$4,460,134	$11,468	$2,067,727
35	% CHANGE	**14.6119%**	**15.2410%**	**16.8761%**	**12.1728%**	**10.6135%**	**9.5728%**	**16.6439%**	**34.8252%**

	E. TOTAL PROPOSED BASE REVENUES INCLUDING MISCELLANEOUS REVENUES AND RIDER EDR	NORTH CAROLINA JURISDICTIONAL	RESIDENTIAL	SGS & PUBLIC AUTH	LGS	6VP	NS	TRAFFIC	OUTDOOR & ST LIGHTS
36	PRESENT BASE NON FUEL AND BASE FUEL REVENUE	$392,568,168	$197,901,068	$77,890,820	$45,003,331	$19,006,996	$46,681,075	$69,815	$6,015,064
37	PROPOSED BASE NON FUEL AND BASE FUEL REVENUE	$449,192,142	$227,778,878	$90,676,553	$50,458,802	$21,019,396	$51,126,726	$80,846	$8,050,941
38	CHANGE	$56,623,974	$29,877,811	$12,785,733	$5,455,472	$2,012,400	$4,445,651	$11,031	$2,035,877
39	% CHANGE	**14.4240%**	**15.0973%**	**16.4149%**	**12.1224%**	**10.5877%**	**9.5235%**	**15.8003%**	**33.8463%**

	F. TOTAL PROPOSED EDIT	NORTH CAROLINA JURISDICTIONAL	RESIDENTIAL	SGS & PUBLIC AUTH	LGS	6VP	NS	TRAFFIC	OUTDOOR & ST LIGHTS
40	PRESENT EDIT CHARGE	$0	$0	$0	$0	$0	$0	$0	$0
41	PROPOSED EDIT CHARGE	$0	$0	$0	$0	$0	$0	$0	$0
42	CHANGE	$0	$0	$0	$0	$0	$0	$0	$0

	G. TOTAL PROPOSED BASE REVENUES AND EDIT	NORTH CAROLINA JURISDICTIONAL	RESIDENTIAL	SGS & PUBLIC AUTH	LGS	6VP	NS	TRAFFIC	OUTDOOR & ST LIGHTS
43	PRESENT BASE NON FUEL AND BASE FUEL AND EDIT REVENUE	$392,568,168	$197,901,068	$77,890,820	$45,003,331	$19,006,996	$46,681,075	$69,815	$6,015,064
44	PROPOSED BASE NON FUEL AND BASE FUEL AND EDIT REVENUE	$449,192,142	$227,778,878	$90,676,553	$50,458,802	$21,019,396	$51,126,726	$80,846	$8,050,941
45	CHANGE	$56,623,974	$29,877,811	$12,785,733	$5,455,472	$2,012,400	$4,445,651	$11,031	$2,035,877
46	% CHANGE	**14.4240%**	**15.0973%**	**16.4149%**	**12.1224%**	**10.5877%**	**9.5235%**	**15.8003%**	**33.8463%**

DOMINION ENERGY NORTH CAROLINA
PRESENT RATES (EFFECTIVE 11/01/19) VERSUS PROPOSED RATES WITH $56,623,974 BASE NON-FUEL INCREASE
12 MONTHS ENDED DECEMBER 31, 2023 - ADJUSTED FOR INCREASED USAGE, WEATHER, AND CUSTOMER GROWTH & EE
DOCKET NO. E-22, SUB 694
SUMMARY OF FINAL RATE DESIGN

		NORTH CAROLINA JURISDICTIONAL	RESIDENTIAL	SGS & PUBLIC AUTH	LGS	6VP	NS	TRAFFIC	OUTDOOR & ST LIGHTS
A.	BASE NON-FUEL MISCELLANEOUS REVENUE								
1	PRESENT LATE PAYMENT REVENUE	$716,699	$342,576	$145,776	$94,277	$38,996	$84,138	$120	$10,817
2	PRESENT LOAD MANAGEMENT CREDITS	$0	$0	$0	$0	$0	$0	$0	$0
3	PRESENT CONTRACT DOLLAR AMOUNT REVENUE	$206,819	$0	$188,034	$18,785	$0	$0	$0	$0
4	PRESENT MISCELLANEOUS SERVICE REVENUE	$589,151	$446,834	$74,381	$201	$12	$4	$799	$66,919
5	PRESENT FACILITIES CHARGE REVENUE	$1,264,929	$96	$616,355	$418,566	$222,432	$7,479	$0	$0
6	PRESENT TOTAL MISCELLANEOUS REVENUE	$2,777,598	$789,507	$1,024,547	$531,828	$261,441	$91,621	$919	$77,735
7	PROPOSED LATE PAYMENT REVENUE	$811,220	$446,213	$165,463	$80,060	$30,906	$69,274	$163	$19,142
8	PROPOSED LOAD MANAGEMENT CREDITS	$0	$0	$0	$0	$0	$0	$0	$0
9	PRESENT CONTRACT DOLLAR AMOUNT REVENUE	$206,819	$0	$188,034	$18,785	$0	$0	$0	$0
10	PROPOSED MISCELLANEOUS SERVICE REVENUE	$235,583	$178,675	$29,743	$80	$5	$2	$319	$26,759
11	PROPOSED FACILITIES CHARGE REVENUE	$1,191,329	$95	$454,670	$474,984	$253,404	$8,175	$0	$0
12	PROPOSED TOTAL MISCELLANEOUS REVENUE	$2,444,951	$624,983	$837,910	$573,909	$284,315	$77,451	$483	$45,901
13	CHANGE	($332,647)	($164,524)	($186,637)	$42,081	$22,874	($14,170)	($436)	($31,835)
14	% CHANGE	-11.9761%	-20.8389%	-18.2165%	7.9125%	8.7492%	-15.4663%	-47.4663%	-40.9526%
	BASE NON-FUEL RIDER EDR REVENUE								
15	PRESENT EDR REVENUE	($37,798)	($20,418)	($7,327)	($5,408)	($2,058)	($2,461)	($5)	($119)
16	PROPOSED EDR REVENUE	($42,623)	($23,025)	($8,263)	($6,099)	($2,321)	($2,775)	($6)	($135)
17	CHANGE	($4,826)	($2,607)	($935)	($691)	($263)	($314)	($1)	($15)
18	% CHANGE	12.7672%	12.7672%	12.7672%	12.7672%	12.7672%	12.7672%	12.7672%	12.7672%
B.	BASE NON-FUEL RATE SCHEDULE REVENUE								
19	PRESENT BASE NON-FUEL RATE SCHEDULE REVENUE	$253,168,781	$140,543,919	$50,282,973	$25,192,890	$9,824,655	$22,022,655	$50,962	$5,250,727
20	PROPOSED BASE NON-FUEL RATE SCHEDULE REVENUE	$310,130,227	$170,587,442	$63,256,722	$30,607,029	$11,815,273	$26,483,344	$62,430	$7,317,988
21	CHANGE	$56,961,447	$30,043,524	$12,973,749	$5,414,139	$1,990,617	$4,460,689	$11,468	$2,067,260
22	% CHANGE	22.4994%	21.3766%	25.8015%	21.4907%	20.2614%	20.2550%	22.5031%	39.3709%
C.	TOTAL BASE NON-FUEL REVENUE								
23	PRESENT BASE NON-FUEL REVENUE (A.6 + B.15 + B.191)	$255,908,581	$141,313,007	$51,300,192	$25,719,310	$10,084,039	$22,111,815	$51,876	$5,328,343
24	PROPOSED BASE NON-FUEL REVENUE (A.12 + A.16 + B.20)	$312,532,555	$171,189,399	$64,086,369	$31,174,839	$12,097,267	$26,558,020	$62,907	$7,363,754
25	CHANGE	$56,623,974	$29,876,393	$12,786,177	$5,455,529	$2,013,229	$4,446,205	$11,031	$2,035,411
26	% CHANGE	22.1266%	21.1420%	24.9242%	21.2118%	19.9645%	20.1078%	21.2646%	38.1997%
D.	BASE FUEL REVENUE								
27	PRESENT BASE FUEL REVENUE + PRESENT RIDER A REVENUE	$136,659,587	$56,588,061	$26,591,644	$19,283,367	$8,922,606	$24,569,249	$17,939	$686,720
28	PROPOSED BASE FUEL REVENUE	$136,659,587	$56,588,061	$26,591,644	$19,283,367	$8,922,606	$24,569,249	$17,939	$686,720
29	CHANGE	$0	$0	$0	$0	$0	$0	$0	$0
30	% CHANGE	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
E.	TOTAL BASE REVENUE (BASE NON-FUEL + BASE FUEL)								
31	PRESENT TOTAL BASE REVENUE (C.23 + D.27)	$392,568,168	$197,901,067	$77,891,836	$45,002,677	$19,006,645	$46,681,065	$69,815	$6,015,064
32	PROPOSED TOTAL BASE REVENUE (C.24 + D.28)	$449,192,142	$227,777,460	$90,678,013	$50,458,206	$21,019,874	$51,127,269	$80,846	$8,050,474
33	CHANGE	$56,623,974	$29,876,393	$12,786,177	$5,455,529	$2,013,229	$4,446,205	$11,031	$2,035,411
34	% CHANGE	14.4240%	15.0966%	16.4153%	12.1227%	10.5922%	9.5246%	15.8006%	33.8386%
F.	TOTAL RIDER EDIT REVENUE								
35	PRESENT TOTAL RIDER EDIT REVENUE	$0	$0	$0	$0	$0	$0	$0	$0
36	PROPOSED TOTAL RIDER EDIT REVENUE	$0	$0	$0	$0	$0	$0	$0	$0
37	CHANGE	$0	$0	$0	$0	$0	$0	$0	$0
G.	TOTAL BASE REVENUE AND RIDER EDIT REVENUE								
38	PRESENT TOTAL BASE REVENUE AND RIDER EDIT REVENUE (E.31 + F.35)	$392,568,168	$197,901,067	$77,891,836	$45,002,677	$19,006,645	$46,681,065	$69,815	$6,015,064
39	PROPOSED TOTAL BASE REVENUE AND RIDER EDIT REVENUE (E.32 + F.36)	$449,192,142	$227,777,460	$90,678,013	$50,458,206	$21,019,874	$51,127,269	$80,846	$8,050,474
40	CHANGE	$56,623,974	$29,876,393	$12,786,177	$5,455,529	$2,013,229	$4,446,205	$11,031	$2,035,411
41	% CHANGE	14.4240%	15.0966%	16.4153%	12.1227%	10.5922%	9.5246%	15.8006%	33.8386%
H.	RIDER B								
42	RIDER B REVENUE EFFECTIVE 2/1/2024	$7,253,542	$3,003,128	$1,411,750	$1,023,290	$473,540	$1,304,439	$952	$36,444
43	RIDER B REVENUE EFFECTIVE 2/1/2024	$7,253,542	$3,003,128	$1,411,750	$1,023,290	$473,540	$1,304,439	$952	$36,444
44	CHANGE	$0	$0	$0	$0	$0	$0	$0	$0
45	% CHANGE	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
I.	RIDER B1								
46	RIDER B1 REVENUE EFFECTIVE 2/1/2024	$24,820,953	$10,199,943	$4,653,519	$3,502,779	$1,595,839	$4,750,996	$3,119	$114,758
47	RIDER B1 REVENUE EFFECTIVE 2/1/2024	$24,820,953	$10,199,943	$4,653,519	$3,502,779	$1,595,839	$4,750,996	$3,119	$114,758
48	CHANGE	$0	$0	$0	$0	$0	$0	$0	$0
49	% CHANGE	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
J.	NON-FUEL RIDER REVENUE (DSM/EE, REPS; EXCLUDES RIDER EDIT)								
50	NON-FUEL RIDER REVENUE EFFECTIVE 2/1/2024	$6,036,504	$2,954,953	$2,164,218	$916,514	$820	$0	$0	$0
51	NON-FUEL RIDER REVENUE EFFECTIVE 2/1/2024	$6,036,504	$2,954,953	$2,164,218	$916,514	$820	$0	$0	$0
52	CHANGE	$0	$0	$0	$0	$0	$0	$0	$0
53	% CHANGE	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
K.	TOTAL REVENUE INCLUDING BASE REVENUE, RIDER EDIT REVENUE, RIDER B, AND RIDER B1								
54	PRESENT TOTAL REVENUE (G.38 + H.42 + I.46 + J.50)	$430,679,167	$214,059,091	$86,121,322	$50,445,259	$21,076,843	$52,736,500	$73,886	$6,166,266
55	PROPOSED TOTAL REVENUE (G.39 + H.43 + I.47 + J.51)	$487,303,141	$243,935,484	$98,907,499	$55,900,788	$23,090,072	$57,182,704	$84,917	$8,201,676
56	CHANGE	$56,623,974	$29,876,393	$12,786,177	$5,455,529	$2,013,229	$4,446,205	$11,031	$2,035,411
57	% CHANGE	13.1476%	13.9571%	14.8467%	10.8148%	9.5519%	8.4310%	14.9300%	33.0088%

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
SUMMARY OF NORTH CAROLINA JURISDICTION AND CUSTOMER CLASS RATES OF RETURN
PER BOOKS, ANNUALIZED, FULLY ADJUSTED AND FULLY ADJUSTED WITH INCREASE

PER BOOKS CLASS RATE OF RETURNS - FROM ITEM 45a

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$86,703,259	$49,032,227	$17,803,773	$12,590,205	$3,311,263	$3,655,655	$298,327	$11,808
Rate Base	$1,594,851,513	$775,661,985	$325,326,317	$161,595,895	$202,505,925	$91,027,589	$38,511,976	$221,826
ROR	5.4364%	6.3213%	5.4726%	7.7912%	1.6351%	4.0160%	0.7746%	5.3233%
Index		1.16	1.01	1.43	0.30	0.74	0.14	0.98

PER BOOKS CLASS RATE OF RETURNS WITH ANNUALIZED REVENUE - FROM ITEM 45b

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$84,297,043	$51,222,986	$17,075,360	$9,787,531	$3,728,841	$2,190,197	$282,616	$9,511
Rate Base	$1,594,851,513	$775,661,985	$325,326,317	$161,595,895	$202,505,925	$91,027,589	$38,511,976	$221,826
ROR	5.2856%	6.6038%	5.2487%	6.0568%	1.8413%	2.4061%	0.7338%	4.2877%
Index		1.25	0.99	1.15	0.35	0.46	0.14	0.81

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS BEFORE REVENUE INCREASE - FROM ITEM 45c, COL. 3

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$61,939,239	$42,160,836	$12,284,929	$6,185,878	$846,217	$515,156	($61,655)	$7,878
Rate Base	$1,330,125,491	$659,956,973	$271,535,534	$131,761,654	$156,945,947	$73,368,201	$36,353,636	$203,546
ROR	4.6566%	6.3884%	4.5242%	4.6947%	0.5392%	0.7022%	-0.1696%	3.8703%
Index		1.37	0.97	1.01	0.12	0.15	-0.04	0.83

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS AND AFTER REVENUE INCREASE - FROM ITEM 45c, COLS. 4 & 5

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Revenue Increase	$56,623,974	$29,877,350	$12,786,611	$5,455,610	$4,445,187	$2,012,764	$2,035,421	$11,031
Adjusted NOI	$103,724,727	$64,208,734	$21,720,770	$10,211,829	$4,126,529	$2,000,469	$1,440,377	$16,018
Rate Base	$1,353,326,351	$670,287,954	$276,231,682	$134,818,588	$160,374,867	$74,779,120	$36,628,541	$205,598
ROR	7.6644%	9.5793%	7.8632%	7.5745%	2.5731%	2.6752%	3.9324%	7.7911%
Index		1.25	1.03	0.99	0.34	0.35	0.51	1.02

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & MODIFIED A&E BASELINE FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
SUMMARY OF NORTH CAROLINA JURISDICTION AND CUSTOMER CLASS RATES OF RETURN
PER BOOKS, ANNUALIZED, FULLY ADJUSTED AND FULLY ADJUSTED WITH INCREASE

PER BOOKS CLASS RATE OF RETURNS - FROM ITEM 45a

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$86,703,259	$46,837,624	$16,807,928	$12,406,450	$5,645,147	$4,720,386	$274,001	$11,722
Rate Base	$1,594,851,513	$828,551,058	$349,325,773	$166,024,329	$146,260,248	$65,367,989	$39,098,214	$223,901
ROR	5.4364%	5.6530%	4.8115%	7.4727%	3.8597%	7.2213%	0.7008%	5.2355%
Index		1.04	0.89	1.37	0.71	1.33	0.13	0.96

PER BOOKS CLASS RATE OF RETURNS WITH ANNUALIZED REVENUE - FROM ITEM 45b

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$84,297,043	$49,029,107	$16,079,844	$9,603,836	$6,061,954	$3,254,577	$258,299	$9,425
Rate Base	$1,594,851,513	$828,551,058	$349,325,773	$166,024,329	$146,260,248	$65,367,989	$39,098,214	$223,901
ROR	5.2856%	5.9175%	4.6031%	5.7846%	4.1446%	4.9789%	0.6606%	4.2095%
Index		1.12	0.87	1.09	0.78	0.94	0.12	0.80

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS BEFORE REVENUE INCREASE - FROM ITEM 45c, COL. 3

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$61,939,240	$38,944,088	$10,825,267	$5,916,538	$4,267,116	$2,075,789	($97,311)	$7,752
Rate Base	$1,330,125,491	$700,556,479	$289,958,358	$135,161,075	$113,769,794	$53,670,993	$36,803,653	$205,139
ROR	4.6566%	5.5590%	3.7334%	4.3774%	3.7507%	3.8676%	-0.2644%	3.7787%
Index		1.19	0.80	0.94	0.81	0.83	-0.06	0.81

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS AND AFTER REVENUE INCREASE - FROM ITEM 45c, COLS. 4 & 5

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Revenue Increase	$56,623,974	$29,876,393	$12,786,177	$5,455,529	$4,446,205	$2,013,228	$2,035,411	$11,031
Adjusted NOI	$103,724,727	$60,991,280	$20,260,787	$9,942,429	$7,548,179	$3,561,445	$1,404,714	$15,892
Rate Base	$1,353,326,351	$711,127,830	$294,763,578	$138,238,136	$116,943,089	$54,965,295	$37,081,222	$207,201
ROR	7.6644%	8.5767%	6.8736%	7.1922%	6.4546%	6.4794%	3.7882%	7.6699%
Index		1.12	0.90	0.94	0.84	0.85	0.49	1.00

DOMINION ENERGY NORTH CAROLINA
STUDY USING SWPA FACTORS @ JURIS LEVEL & SWCP FACTORS @ NC CLASS LEVEL
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
SUMMARY OF NORTH CAROLINA JURISDICTION AND CUSTOMER CLASS RATES OF RETURN
PER BOOKS, ANNUALIZED, FULLY ADJUSTED AND FULLY ADJUSTED WITH INCREASE

PER BOOKS CLASS RATE OF RETURNS - FROM ITEM 45a

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$86,703,258	$41,461,656	$17,899,224	$13,281,441	$8,766,795	$4,733,302	$549,247	$11,593
Rate Base	$1,594,851,513	$958,109,730	$323,025,980	$144,937,388	$71,029,787	$65,056,712	$32,464,902	$227,014
ROR	5.4364%	4.3274%	5.5411%	9.1636%	12.3424%	7.2757%	1.6918%	5.1067%
Index		0.80	1.02	1.69	2.27	1.34	0.31	0.94

PER BOOKS CLASS RATE OF RETURNS WITH ANNUALIZED REVENUE - FROM ITEM 45b

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$84,327,737	$43,671,531	$17,176,487	$10,481,666	$9,185,361	$3,268,780	$534,601	$9,310
Rate Base	$1,594,851,513	$958,109,729	$323,025,980	$144,937,388	$71,029,788	$65,056,711	$32,464,903	$227,014
ROR	5.2875%	4.5581%	5.3174%	7.2319%	12.9317%	5.0245%	1.6467%	4.1011%
Index		0.86	1.01	1.37	2.45	0.95	0.31	0.78

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS BEFORE REVENUE INCREASE - FROM ITEM 45c, COL. 3

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$61,939,240	$31,064,235	$12,424,838	$7,199,057	$8,842,687	$2,094,720	$306,136	$7,567
Rate Base	$1,330,125,491	$800,010,254	$269,769,715	$118,974,000	$56,020,257	$53,432,045	$31,711,691	$207,529
ROR	4.6566%	3.8830%	4.6057%	6.0510%	15.7848%	3.9203%	0.9654%	3.6462%
Index		0.83	0.99	1.30	3.39	0.84	0.21	0.78

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS AND AFTER REVENUE INCREASE - FROM ITEM 45c, COLS. 4 & 5

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Revenue Increase	$56,623,974	$29,874,049	$12,786,653	$5,455,911	$4,447,566	$2,013,234	$2,035,531	$11,031
Adjusted NOI	$103,724,727	$53,109,698	$21,860,709	$11,225,230	$12,124,755	$3,580,379	$1,808,249	$15,707
Rate Base	$1,353,326,351	$811,170,422	$274,455,408	$121,955,225	$58,851,646	$54,724,932	$31,959,113	$209,605
ROR	7.6644%	6.5473%	7.9651%	9.2044%	20.6022%	6.5425%	5.6580%	7.4938%
Index		0.85	1.04	1.20	2.69	0.85	0.74	0.98

DOMINION ENERGY NORTH CAROLINA
SUMMER WINTER PEAK & AVERAGE STUDY
EOP - PERIOD ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694
SUMMARY OF NORTH CAROLINA JURISDICTION AND CUSTOMER CLASS RATES OF RETURN
PER BOOKS, ANNUALIZED, FULLY ADJUSTED AND FULLY ADJUSTED WITH INCREASE

PER BOOKS CLASS RATE OF RETURNS - FROM ITEM 45a

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$86,703,259	$47,069,722	$18,110,013	$11,870,756	$5,136,858	$4,117,110	$387,896	$10,904
Rate Base	$1,594,851,513	$823,640,771	$318,044,620	$178,678,915	$158,156,503	$79,792,715	$36,292,242	$245,747
ROR	5.4364%	5.7148%	5.6942%	6.6436%	3.2480%	5.1598%	1.0688%	4.4370%
Index		1.05	1.05	1.22	0.60	0.95	0.20	0.82

PER BOOKS CLASS RATE OF RETURNS WITH ANNUALIZED REVENUE - FROM ITEM 45b

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$84,327,736	$49,277,746	$17,387,206	$9,071,447	$5,556,622	$2,652,793	$373,302	$8,620
Rate Base	$1,594,851,513	$823,640,771	$318,044,620	$178,678,915	$158,156,503	$79,792,715	$36,292,242	$245,747
ROR	5.2875%	5.9829%	5.4669%	5.0770%	3.5134%	3.3246%	1.0286%	3.5077%
Index		1.13	1.03	0.96	0.66	0.63	0.19	0.66

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS BEFORE REVENUE INCREASE - FROM ITEM 45c, COL. 3

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$61,939,239	$39,281,392	$12,733,509	$5,132,276	$3,523,732	$1,191,949	$69,834	$6,547
Rate Base	$1,330,125,491	$696,222,134	$265,887,221	$145,058,094	$123,220,232	$64,825,046	$34,692,015	$220,750
ROR	4.6566%	5.6421%	4.7891%	3.5381%	2.8597%	1.8387%	0.2013%	2.9657%
Index		1.21	1.03	0.76	0.61	0.39	0.04	0.64

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS AND AFTER REVENUE INCREASE - FROM ITEM 45c, COLS. 4 & 5

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Revenue Increase	$56,623,974	$29,876,494	$12,786,745	$5,455,296	$4,445,983	$2,012,965	$2,035,460	$11,031
Adjusted NOI	$103,724,727	$61,328,659	$22,169,448	$9,157,995	$6,804,632	$2,677,410	$1,571,895	$14,687
Rate Base	$1,353,326,351	$706,768,613	$270,549,802	$148,193,748	$126,448,791	$66,185,389	$34,957,109	$222,899
ROR	7.6644%	8.6773%	8.1942%	6.1797%	5.3813%	4.0453%	4.4966%	6.5891%
Index		1.13	1.07	0.81	0.70	0.53	0.59	0.86

DOMINION ENERGY NORTH CAROLINA
PRESENT RATES (EFFECTIVE 11/01/19) VERSUS PROPOSED RATES WITH $56,623,974 BASE NON-FUEL INCREASE
12 MONTHS ENDED DECEMBER 31, 2023 - ADJUSTED FOR INCREASED USAGE, WEATHER, AND CUSTOMER GROWTH & EE
DOCKET NO. E-22, SUB 694

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(16)	(17)
				PRESENT ANNUALIZED REVENUE								PROPOSED REVENUE BASED ON $56,623,974 BASE NON-FUEL REVENUE INCREASE EDIT RIDERS AND FUEL REVENUE DECREASE							
LINE NO.		BOOKED 12/2023 CUST INCLUDING GROWTH THROUGH	BOOKED KWH SALES INCLUDING GROWTH THROUGH	BASE NON-FUEL REVENUE #	RIDER NON-FUEL REVENUE ##	BASE FUEL REVENUE	RIDER A FUEL REVENUE ##	RIDER B FUEL REVENUE ##	RIDER B1 FUEL REVENUE ##	FUEL REVENUE (5)+(6)+(7)+(8)	TOTAL REVENUE	BASE NON-FUEL REVENUE ###	RIDER NON-FUEL REVENUE ####	BASE FUEL REVENUE #####	RIDER A FUEL REVENUE @	RIDER B FUEL REVENUE @	RIDER B1 FUEL REVENUE @	FUEL REVENUE (13)+(14)+(15)+(16)	TOTAL REVENUE
	RESIDENTIAL																		
1	SCHEDULE 1	107,612	1,504,186,279	$131,347,602	$2,743,864	$31,802,363	$20,653,518	$2,783,833	$9,455,122	$64,694,836	$198,786,302	$159,425,245	$2,743,864	$52,455,881	$0	$2,783,833	$9,455,122	$64,694,836	$226,863,945
2	SCHEDULE 1DF (DUEL FUEL)	929 *	2,210,435	$112,983	$2,911	$46,456	$30,170	$4,067	$13,812	$94,503	$210,397	$137,135	$2,911	$76,625	$0	$4,067	$13,812	$94,503	$234,550
3	SCHEDULE 1P (TIME-OF-USAGE)	436	13,301,314	$922,145	$20,638	$279,947	$181,807	$24,505	$83,231	$569,489	$1,512,272	$1,119,287	$20,638	$461,753	$0	$24,505	$83,231	$569,489	$1,709,414
4	SCHEDULE 1T (TIME-OF-USAGE)	35	671,122	$57,206	$1,142	$14,033	$9,114	$1,228	$4,172	$28,548	$86,895	$69,435	$1,142	$23,147	$0	$1,228	$4,172	$28,548	$99,124
5	SCHEDULE 1W (WATER HEATER)	15 *	111,866	$3,563	$147	$2,369	$1,539	$207	$704	$4,820	$8,530	$4,324	$147	$3,908	$0	$207	$704	$4,820	$9,291
6	SUBTOTAL - RESIDENTIAL	108,083 **	1,520,481,017	$132,443,498	$2,768,702	$32,145,168	$20,876,147	$2,813,840	$9,557,041	$65,392,196	$200,604,396	$160,755,426	$2,768,702	$53,021,315	$0	$2,813,840	$9,557,041	$65,392,196	$228,916,324
7	INCREASED USAGE, WEATHER & CUST GROWTH	1,714	102,282,823	$8,100,421	$186,251	$2,162,407	$1,404,339	$189,287	$642,903	$4,398,936	$12,685,607	$9,832,016	$186,251	$3,566,746	$0	$189,287	$642,903	$4,398,936	$14,417,202
8	ENERGY REDUCTION DUE TO EE		0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	SUBTOTAL - RESIDENTIAL ADJ. FOR GROWTH	109,797 **	1,622,763,840	$140,543,919	$2,954,953	$34,307,575	$22,280,486	$3,003,128	$10,199,943	$69,791,132	$213,290,003	$170,587,442	$2,954,953	$56,588,061	$0	$3,003,128	$10,199,943	$69,791,132	$243,333,527
	SMALL GEN SERVICE & PUBLIC AUTHORITY																		
10	SCHEDULE 5	14,801	500,603,442	$34,733,821	$1,549,506	$10,587,759	$6,884,797	$927,618	$3,057,685	$21,457,858	$57,741,185	$43,686,332	$1,549,506	$17,472,555	$0	$927,618	$3,057,685	$21,457,858	$66,693,696
11	SCHEDULE 5C (COTTON GIN)	19	4,066,462	$247,376	$7,956	$86,006	$55,926	$7,535	$24,838	$174,305	$429,637	$311,200	$7,956	$141,932	$0	$7,535	$24,838	$174,305	$493,461
12	SCHEDULE 5P (TIME-OF-USAGE)	1,057	122,853,635	$6,557,249	$262,826	$2,598,354	$1,689,606	$227,648	$750,390	$5,265,998	$12,086,074	$8,249,128	$262,826	$4,287,960	$0	$227,648	$750,390	$5,265,998	$13,777,953
13	SCHEDULE 7	50 *	864,339	$50,081	$1,545	$18,281	$11,887	$1,602	$5,279	$37,049	$88,675	$63,010	$1,545	$30,168	$0	$1,602	$5,279	$37,049	$101,604
14	SCHEDULE 30 - (PUBLIC AUTHORITY)	1,218	71,055,929	$4,746,761	$175,249	$1,502,833	$977,232	$131,667	$434,010	$3,045,741	$7,967,751	$5,980,836	$175,249	$2,480,065	$0	$131,667	$434,010	$3,045,741	$9,201,826
15	SCHEDULE 42 - (ALL ELEC / PUB AUTH)	998	46,136,472	$2,950,042	$120,854	$975,786	$634,515	$85,491	$281,802	$1,977,594	$5,048,490	$3,711,165	$120,854	$1,610,301	$0	$85,491	$281,802	$1,977,594	$5,809,613
16	SUBTOTAL - SGS & PUBLIC AUTHORITY	18,093 **	745,580,278	$49,285,329	$2,117,936	$15,769,019	$10,253,963	$1,381,560	$4,554,003	$31,958,545	$83,361,810	$62,001,672	$2,117,936	$26,022,982	$0	$1,381,560	$4,554,003	$31,958,545	$96,078,153
17	INCREASED USAGE, WEATHER & CUST GROWTH	328	16,292,640	$997,643	$46,282	$344,589	$224,073	$30,190	$99,515	$698,368	$1,742,292	$1,255,050	$46,282	$568,662	$0	$30,190	$99,515	$698,368	$1,999,699
18	ENERGY REDUCTION DUE TO EE		0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	SUBTOTAL - SGS & PA ADJ. FOR GROWTH	18,421 **	761,872,918	$50,282,973	$2,164,218	$16,113,608	$10,478,036	$1,411,750	$4,653,519	$32,656,913	$85,104,103	$63,256,722	$2,164,218	$26,591,644	$0	$1,411,750	$4,653,519	$32,656,913	$98,077,852
	LARGE GEN SERVICE																		
20	SCHEDULE 6C	2	5,281,121	$222,692	$8,555	$110,798	$72,219	$9,712	$33,245	$225,974	$457,221	$270,549	$8,555	$183,017	$0	$9,712	$33,245	$225,974	$505,077
21	SCHEDULE 6L	4	335,253,672	$13,766,991	$542,839	$6,927,737	$4,515,577	$607,250	$2,078,651	$14,129,216	$28,439,047	$16,725,605	$542,839	$11,443,315	$0	$607,250	$2,078,651	$14,129,216	$31,397,660
22	SCHEDULE 6P	24	93,022,502	$4,689,959	$153,120	$1,939,813	$1,264,392	$170,034	$582,036	$3,956,276	$8,799,354	$5,697,825	$153,120	$3,204,205	$0	$170,034	$582,036	$3,956,276	$9,807,221
23	SCHEDULE 10 0.0000%	25	138,637,609	$7,054,897	$227,441	$2,892,406	$1,885,303	$253,534	$867,860	$5,899,103	$13,181,441	$8,571,103	$227,441	$4,777,709	$0	$253,534	$867,860	$5,899,103	$14,697,647
24	SCHEDULE LGS-RTP WITH CBL	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	SCHEDULE LGS-RTP WITH ED	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	SUBTOTAL - LARGE GENERAL SERVICE	55	572,194,905	25,734,539	931,955	$11,870,755	$7,737,492	$1,040,530	$3,561,792	24,210,568	50,877,062	$31,265,082	$931,955	$19,608,246	$0	$1,040,530	$3,561,792	24,210,568	$56,407,606
27	INCREASED USAGE, WEATHER & CUST GROWTH	1	(9,480,412)	($541,649)	($15,441)	($196,681)	($128,199)	($17,240)	($59,014)	($401,133)	($958,223)	($658,054)	($15,441)	($324,879)	$0	($17,240)	($59,014)	($401,133)	($1,074,628)
28	ENERGY REDUCTION DUE TO EE		0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	SUBTOTAL - LGS ADJ. FOR GROWTH	56	562,714,493	$25,192,890	$916,514	$11,674,074	$7,609,293	$1,023,290	$3,502,779	$23,809,436	$49,918,839	$30,607,029	$916,514	$19,283,367	$0	$1,023,290	$3,502,779	$23,809,436	$55,332,978
30	**SCHEDULE 6VP**	3	255,486,894	$9,583,715	$800	$5,275,804	$3,427,868	$461,920	$1,556,682	$10,722,274	$20,306,789	$11,525,514	$800	$8,703,672	$0	$461,920	$1,556,682	$10,722,274	$22,248,588
31	INCREASED USAGE, WEATHER & CUST GROWTH	0	6,426,584	$240,941	$20	$132,709	$86,225	$11,619	$39,157	$269,711	$510,672	$289,759	$20	$218,934	$0	$11,619	$39,157	$269,711	$559,490
32	SUBTOTAL - 6VP ADJ. FOR GROWTH	3	261,913,478	$9,824,655	$820	$5,408,513	$3,514,093	$473,540	$1,595,839	$10,991,985	$20,817,460	$11,815,273	$820	$8,922,606	$0	$473,540	$1,595,839	$10,991,985	$22,808,078
33	**SCHEDULE NS**	1	657,936,799	$19,805,302	$0	$13,395,593	$8,699,898	$1,173,101	$4,272,642	$27,541,234	$47,346,536	$23,816,866	$0	$22,095,492	$0	$1,173,101	$4,272,642	$27,541,234	$51,358,100
34	INCREASED USAGE, WEATHER & CUST GROWTH	0	73,661,017	$2,217,354	$0	$1,499,738	$974,020	$131,338	$478,355	$3,083,450	$5,300,804	$2,666,479	$0	$2,473,758	$0	$131,338	$478,355	$3,083,450	$5,749,929
35	SUBTOTAL - SCHEDULE NS ADJ. FOR GROWTH	1	731,597,816	$22,022,655	$0	$14,895,332	$9,673,918	$1,304,439	$4,750,996	$30,624,685	$52,647,340	$26,483,344	$0	$24,569,249	$0	$1,304,439	$4,750,996	$30,624,685	$57,108,029
36	**TRAFFIC CONTROL**																		
37	SCHEDULE 30T - TRAFFIC CONTROL	195	465,629	$48,204	$0	$9,862	$6,405	$863	$2,828	$19,958	$68,163	$59,052	$0	$16,267	$0	$863	$2,828	$19,958	$79,010
38	INCREASED USAGE, WEATHER & CUST GROWTH	1	47,870	$2,757	$0	$1,014	$658	$89	$291	$2,052	$4,809	$3,378	$0	$1,672	$0	$89	$291	$2,052	$5,430
39	SUBTOTAL - 30T ADJ. FOR GROWTH	196	513,499	$50,962	$0	$10,876	$7,063	$952	$3,119	$22,010	$72,972	$62,430	$0	$17,939	$0	$952	$3,119	$22,010	$84,440
	OUTDOOR LIGHTING SERVICE																		
40	SCHEDULE 26 - OUTDOOR LIGHTING	15,303 *	13,922,900	$3,403,010	$0	$294,887	$191,509	$25,813	$81,282	$593,491	$3,996,501	$4,742,848	$0	$486,397	$0	$25,813	$81,282	$593,491	$5,336,339
41	SCHEDULE 26 - STREET & ROADWAY	1,025	7,557,364	$1,753,735	$0	$160,065	$103,952	$14,011	$44,120	$322,148	$2,075,883	$2,444,155	$0	$264,017	$0	$14,011	$44,120	$322,148	$2,766,303
42	SUBTOTAL - OUTDOOR LIGHTING SERVICE	1,025 **	21,480,264	$5,156,744	$0	$454,952	$295,461	$39,824	$125,402	$915,639	$6,072,384	$7,187,003	$0	$750,413	$0	$39,824	$125,402	$915,639	$8,102,642
43	INCREASED USAGE, WEATHER & CUST GROWTH	-2 *	(1,823,177)	$93,983	$0	($38,615)	($25,078)	($3,380)	($10,644)	($77,717)	$16,266	$130,985	$0	($63,693)	$0	($3,380)	($10,644)	($77,717)	$53,268
44	ENERGY REDUCTION DUE TO EE		0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
45	SUBTOTAL - ODL SERVICE ADJ. FOR GROWTH	1,023 **	19,657,087	$5,250,727	$0	$416,337	$270,383	$36,444	$114,758	$837,923	$6,088,650	$7,317,988	$0	$686,720	$0	$36,444	$114,758	$837,923	$8,155,910
46	SUBTOTAL - NUMBERED RATE SCHEDULES	129,497 **	3,961,033,131	$253,168,781	$6,036,504	$82,826,315	$53,833,272	$7,253,542	$24,820,953	$168,734,082	$427,939,367	$310,130,227	$6,036,504	$136,659,587	$0	$7,253,542	$24,820,953	$168,734,082	$484,900,813
47	ECONOMIC DEVELOPMENT RIDER			($37,798)	$0	$0	$0	$0	$0	$0	($37,798)	($42,623)	$0	$0	$0	$0	$0	$0	($42,623)
48	LOAD MANAGEMENT CREDITS			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
49	FACILITIES CHARGES			$1,264,929	$0	$0	$0	$0	$0	$0	$1,264,929	$1,191,329	$0	$0	$0	$0	$0	$0	$1,191,329
50	CONTRACT DOLLAR AMOUNT			$206,819	$0	$0	$0	$0	$0	$0	$206,819	$206,819	$0	$0	$0	$0	$0	$0	$206,819
51	TOTAL - SALES OF ELECTRICITY	129,497 **	3,961,033,131	$254,602,731	$6,036,504	$82,826,315	$53,833,272	$7,253,542	$24,820,953	$168,734,082	$429,373,317	$311,485,752	$6,036,504	$136,659,587	$0	$7,253,542	$24,820,953	$168,734,082	$486,256,338
52	MISCELLANEOUS SERVICE REVENUE			$589,151	$0	$0	$0	$0	$0	$0	$589,151	$235,583	$0	$0	$0	$0	$0	$0	$235,583
53	FORFEITED DISCOUNT (LATE PAYMENT)			$716,699	$0	$0	$0	$0	$0	$0	$716,699	$811,220	$0	$0	$0	$0	$0	$0	$811,220
54	TOTAL - MISCELLANEOUS REVENUE			$1,305,850	$0	$0	$0	$0	$0	$0	$1,305,850	$1,046,803	$0	$0	$0	$0	$0	$0	$1,046,803
55	TOTAL - SALES OF ELECTRICITY	129,497 **	3,961,033,131	$255,908,581	$6,036,504	$82,826,315	$53,833,272	$7,253,542	$24,820,953	$168,734,082	$430,679,167	$312,532,555	$6,036,504	$136,659,587	$0	$7,253,542	$24,820,953	$168,734,082	$487,303,141

NOTES:
* DUPLICATE CUSTOMERS.
** EXCLUDES DUPLICATE CUSTOMERS.
# REVENUE BASED ON RATES EFFECTIVE 11/01/2019 FROM DOCKET E-22 SUB 562 EXCLUDING BASE FUEL.
BASED ON RATES EFFECTIVE 2/1/2024.
NON-FUEL BASE REVENUE INCLUDES PROPOSED NON-FUEL BASE REVENUE INCREASE OF $56,623,974.
NON-FUEL RIDER REVENUE INCLUDES PROPOSED RIDER EDIT CHARGE OF $ COMBINED WITH CURRENT NON-FUEL RIDER REVENUE ANNUALIZED WITH RATES EFFECTIVE 02/01/2024.
BASED ON APPROVED BASE FUEL RATES.
@ BASED ON RIDER A RATES, RIDER B RATES, AND RIDER B1 RATES EFFECTIVE 2/1/2024.
(1) FUEL REVENUE REFLECTS THE 5% ENERGY CONSERVATION DISCOUNT AND THE 2% DISCOUNT FOR THOSE CUSTOMERS WHOSE METERS ARE READ ON THE COMPANY'S SIDE OF THE TRANSFORMERS.

DOMINION ENERGY NORTH CAROLINA
PRESENT RATES (EFFECTIVE 11/01/19) VERSUS PROPOSED RATES WITH $ BASE NON-FUEL INCREASE
12 MONTHS ENDED DECEMBER 31, 2023 - ADJUSTED FOR INCREASED USAGE, WEATHER, AND CUSTOMER GROWTH & EE
DOCKET NO. E-22, SUB 694

	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)	(33)	(34)	(35)	(36)	(37)	(38)
		TOTAL CHANGE								PERCENTAGE CHANGE								CHANGE AND PERCENTAGE CHANGE FROM PRESENT BASE NON-FUEL, BASE FUEL, AND RIDER A			
LINE NO.		BASE NON-FUEL	RIDER NON-FUEL	BASE FUEL	RIDER A FUEL	RIDER B FUEL	RIDER B1 FUEL	TOTAL FUEL	TOTAL	BASE NON-FUEL	RIDER NON-FUEL	BASE FUEL	RIDER A FUEL	RIDER B FUEL	TOTAL B1 FUEL	TOTAL FUEL	TOTAL	PRESENT BASE NON-FUEL + BASE FUEL +	PROPOSED BASE NON-FUEL + BASE FUEL + RIDER A	CHANGE	% CHANGE
	RESIDENTIAL																				
1	SCHEDULE 1	$28,077,643	$0	$20,653,518	($20,653,518)	$0	$0	$0	$28,077,643	21.38%	0.00%	64.94%	-100.00%	0.00%	0.00%	0.00%	14.12%	$183,803,483	$211,881,126	$28,077,643	15.28%
2	SCHEDULE 1DF (DUEL FUEL)	$24,153	$0	$30,170	($30,170)	$0	$0	$0	$24,153	21.38%	0.00%	64.94%	-100.00%	0.00%	0.00%	0.00%	11.48%	$189,608	$213,761	$24,153	12.74%
3	SCHEDULE 1P (TIME-OF-USAGE)	$197,142	$0	$181,807	($181,807)	$0	$0	$0	$197,142	21.38%	0.00%	64.94%	-100.00%	0.00%	0.00%	0.00%	13.04%	$1,383,898	$1,581,040	$197,142	14.25%
4	SCHEDULE 1T (TIME-OF-USAGE)	$12,229	$0	$9,114	($9,114)	$0	$0	$0	$12,229	21.38%	0.00%	64.94%	-100.00%	0.00%	0.00%	0.00%	14.07%	$80,353	$92,582	$12,229	15.22%
5	SCHEDULE 1W (WATER HEATER)	$762	$0	$1,539	($1,539)	$0	$0	$0	$762	21.38%	0.00%	64.94%	-100.00%	0.00%	0.00%	0.00%	8.93%	$7,471	$8,232	$762	10.19%
6	SUBTOTAL - RESIDENTIAL	$28,311,928	$0	$20,876,147	($20,876,147)	$0	$0	$0	$28,311,928	21.38%	0.00%	64.94%	-100.00%	0.00%	0.00%	0.00%	14.11%	$185,464,812	$213,776,741	$28,311,928	15.27%
7	INCREASED USAGE, WEATHER & CUST GROWTH	$1,731,595	$0	$1,404,339	($1,404,339)	$0	$0	$0	$1,731,595	21.38%	0.00%	64.94%	-100.00%	0.00%	0.00%	0.00%	13.65%	$11,667,167	$13,398,762	$1,731,595	14.84%
8	ENERGY REDUCTION DUE TO EE	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	0.00%
9	SUBTOTAL - RESIDENTIAL ADJ. FOR GROWTH	$30,043,524	$0	$22,280,486	($22,280,486)	$0	$0	$0	$30,043,524	21.38%	0.00%	64.94%	-100.00%	0.00%	0.00%	0.00%	14.09%	$197,131,979	$227,175,503	$30,043,524	15.24%
	SMALL GEN SERVICE & PUBLIC AUTHORITY																				
10	SCHEDULE 5	$8,952,511	$0	$6,884,797	($6,884,797)	$0	$0	$0	$8,952,511	25.77%	0.00%	65.03%	-100.00%	0.00%	0.00%	0.00%	15.50%	$52,206,376	$61,158,887	$8,952,511	17.15%
11	SCHEDULE 5C (COTTON GIN)	$63,824	$0	$55,926	($55,926)	$0	$0	$0	$63,824	25.80%	0.00%	65.03%	-100.00%	0.00%	0.00%	0.00%	14.86%	$389,308	$453,132	$63,824	16.39%
12	SCHEDULE 5P (TIME-OF-USAGE)	$1,691,879	$0	$1,689,606	($1,689,606)	$0	$0	$0	$1,691,879	25.80%	0.00%	65.03%	-100.00%	0.00%	0.00%	0.00%	14.00%	$10,845,209	$12,537,089	$1,691,879	15.60%
13	SCHEDULE 7	$12,930	$0	$11,887	($11,887)	$0	$0	$0	$12,930	25.82%	0.00%	65.03%	-100.00%	0.00%	0.00%	0.00%	14.58%	$80,249	$93,179	$12,930	16.11%
14	SCHEDULE 30 - (PUBLIC AUTHORITY)	$1,234,075	$0	$977,232	($977,232)	$0	$0	$0	$1,234,075	26.00%	0.00%	65.03%	-100.00%	0.00%	0.00%	0.00%	15.49%	$7,226,826	$8,460,901	$1,234,075	17.08%
15	SCHEDULE 42 - (ALL ELEC / PUB AUTH)	$761,124	$0	$634,515	($634,515)	$0	$0	$0	$761,124	25.80%	0.00%	65.03%	-100.00%	0.00%	0.00%	0.00%	15.08%	$4,560,343	$5,321,467	$761,124	16.69%
16	SUBTOTAL - SGS & PUBLIC AUTHORITY	$12,716,343	$0	$10,253,963	($10,253,963)	$0	$0	$0	$12,716,343	25.80%	0.00%	65.03%	-100.00%	0.00%	0.00%	0.00%	15.25%	$75,308,311	$88,024,654	$12,716,343	16.89%
17	INCREASED USAGE, WEATHER & CUST GROWTH	$257,407	$0	$224,073	($224,073)	$0	$0	$0	$257,407	25.80%	0.00%	65.03%	-100.00%	0.00%	0.00%	0.00%	14.77%	$1,566,305	$1,823,712	$257,407	16.43%
18	ENERGY REDUCTION DUE TO EE	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	0.00%
19	SUBTOTAL - SGS & PA ADJ. FOR GROWTH	$12,973,749	$0	$10,478,036	($10,478,036)	$0	$0	$0	$12,973,749	25.80%	0.00%	65.03%	-100.00%	0.00%	0.00%	0.00%	15.24%	$76,874,616	$89,848,365	$12,973,749	16.88%
	LARGE GEN SERVICE																				
20	SCHEDULE 6C	$47,857	$0	$72,219	($72,219)	$0	$0	$0	$47,857	21.49%	0.00%	65.18%	-100.00%	0.00%	0.00%	0.00%	10.47%	$405,709	$453,566	$47,857	11.80%
21	SCHEDULE 6L	$2,958,614	$0	$4,515,577	($4,515,577)	$0	$0	$0	$2,958,614	21.49%	0.00%	65.18%	-100.00%	0.00%	0.00%	0.00%	10.40%	$25,210,306	$28,168,920	$2,958,614	11.74%
22	SCHEDULE 6P	$1,007,867	$0	$1,264,392	($1,264,392)	$0	$0	$0	$1,007,867	21.49%	0.00%	65.18%	-100.00%	0.00%	0.00%	0.00%	11.45%	$7,894,164	$8,902,030	$1,007,867	12.77%
23	SCHEDULE 10	$1,516,206	$0	$1,885,303	($1,885,303)	$0	$0	$0	$1,516,206	21.49%	0.00%	65.18%	-100.00%	0.00%	0.00%	0.00%	11.50%	$11,832,607	$13,348,813	$1,516,206	12.81%
24	SCHEDULE LGS-RTP WITH CBL	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	0.00%
25	SCHEDULE LGS-RTP WITH ED	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	0.00%
26	SUBTOTAL - LARGE GENERAL SERVICE	$5,530,543	$0	$7,737,492	($7,737,492)	$0	$0	$0	$5,530,543	21.49%	0.00%	65.18%	-100.00%	0.00%	0.00%	0.00%	10.87%	$45,342,785	$50,873,329	$5,530,543	12.20%
27	INCREASED USAGE, WEATHER & CUST GROWTH	($116,404)	$0	($128,199)	$128,199	$0	$0	$0	($116,404)	21.49%	0.00%	65.18%	-100.00%	0.00%	0.00%	0.00%	12.15%	($866,529)	($982,933)	($116,404)	13.43%
28	ENERGY REDUCTION DUE TO EE	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	0.00%
29	SUBTOTAL - LGS ADJ. FOR GROWTH	$5,414,139	$0	$7,609,293	($7,609,293)	$0	$0	$0	$5,414,139	21.49%	0.00%	65.18%	-100.00%	0.00%	0.00%	0.00%	10.85%	$44,476,257	$49,890,396	$5,414,139	12.17%
30	**SCHEDULE 6VP**	$1,941,799	$0	$3,427,868	($3,427,868)	$0	$0	$0	$1,941,799	20.26%	0.00%	64.97%	-100.00%	0.00%	0.00%	0.00%	9.56%	$18,287,387	$20,229,186	$1,941,799	10.62%
31	INCREASED USAGE, WEATHER & CUST GROWTH	$48,818	$0	$86,225	($86,225)	$0	$0	$0	$48,818	20.26%	0.00%	64.97%	-100.00%	0.00%	0.00%	0.00%	9.56%	$459,875	$508,693	$48,818	10.62%
32	SUBTOTAL - 6VP ADJ. FOR GROWTH	$1,990,617	$0	$3,514,093	($3,514,093)	$0	$0	$0	$1,990,617	20.26%	0.00%	64.97%	-100.00%	0.00%	0.00%	0.00%	9.56%	$18,747,262	$20,737,879	$1,990,617	10.62%
33	**SCHEDULE NS**	$4,011,564	$0	$8,699,898	($8,699,898)	$0	$0	$0	$4,011,564	20.26%	0.00%	64.95%	-100.00%	0.00%	0.00%	0.00%	8.47%	$41,900,793	$45,912,357	$4,011,564	9.57%
34	INCREASED USAGE, WEATHER & CUST GROWTH	$449,125	$0	$974,020	($974,020)	$0	$0	$0	$449,125	20.26%	0.00%	64.95%	-100.00%	0.00%	0.00%	0.00%	8.47%	$4,691,112	$5,140,237	$449,125	9.57%
35	SUBTOTAL - SCHEDULE NS ADJ. FOR GROWTH	$4,460,689	$0	$9,673,918	($9,673,918)	$0	$0	$0	$4,460,689	20.26%	0.00%	64.95%	-100.00%	0.00%	0.00%	0.00%	8.47%	$46,591,905	$51,052,594	$4,460,689	9.57%
	TRAFFIC CONTROL																				
37	SCHEDULE 30T - TRAFFIC CONTROL	$10,847	$0	$6,405	($6,405)	$0	$0	$0	$10,847	22.50%	0.00%	64.94%	-100.00%	0.00%	0.00%	0.00%	15.91%	$64,471	$75,319	$10,847	16.83%
38	INCREASED USAGE, WEATHER & CUST GROWTH	$620	$0	$658	($658)	$0	$0	$0	$620	22.50%	0.00%	64.94%	-100.00%	0.00%	0.00%	0.00%	12.90%	$4,430	$5,050	$620	14.01%
39	SUBTOTAL - 30T ADJ. FOR GROWTH	$11,468	$0	$7,063	($7,063)	$0	$0	$0	$11,468	22.50%	0.00%	64.94%	-100.00%	0.00%	0.00%	0.00%	15.72%	$68,901	$80,369	$11,468	16.64%
	OUTDOOR LIGHTING SERVICE																				
40	SCHEDULE 26 - OUTDOOR LIGHTING	$1,339,838	$0	$191,509	($191,509)	$0	$0	$0	$1,339,838	39.37%	0.00%	64.94%	-100.00%	0.00%	0.00%	0.00%	33.53%	$3,889,406	$5,229,244	$1,339,838	34.45%
41	SCHEDULE 26 - STREET & ROADWAY	$690,421	$0	$103,952	($103,952)	$0	$0	$0	$690,421	39.37%	0.00%	64.94%	-100.00%	0.00%	0.00%	0.00%	33.26%	$2,017,751	$2,708,172	$690,421	34.22%
42	SUBTOTAL - OUTDOOR LIGHTING SERVICE	$2,030,258	$0	$295,461	($295,461)	$0	$0	$0	$2,030,258	39.37%	0.00%	64.94%	-100.00%	0.00%	0.00%	0.00%	33.43%	$5,907,157	$7,937,416	$2,030,258	34.37%
43	INCREASED USAGE, WEATHER & CUST GROWTH	$37,002	$0	($25,078)	$25,078	$0	$0	$0	$37,002	39.37%	0.00%	64.94%	-100.00%	0.00%	0.00%	0.00%	227.48%	$30,290	$67,292	$37,002	122.16%
44	ENERGY REDUCTION DUE TO EE	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	0.00%
45	SUBTOTAL - ODL SERVICE ADJ. FOR GROWTH	$2,067,260	$0	$270,383	($270,383)	$0	$0	$0	$2,067,260	39.37%	0.00%	64.94%	-100.00%	0.00%	0.00%	0.00%	33.95%	$5,937,448	$8,004,708	$2,067,260	34.82%
46	SUBTOTAL - NUMBERED RATE SCHEDULES	$56,961,447	$0	$53,833,272	($53,833,272)	$0	$0	$0	$56,961,447	22.50%	0.00%	65.00%	-100.00%	0.00%	0.00%	0.00%	13.31%	$389,828,367	$446,789,814	$56,961,447	14.61%
47	ECONOMIC DEVELOPMENT RIDER	($4,826)	$0	$0	$0	$0	$0	$0	($4,826)	12.77%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	12.77%	($37,798)	($42,623)	($4,826)	12.77%
48	LOAD MANAGEMENT CREDITS	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	0.00%
49	FACILITIES CHARGES	($73,600)	$0	$0	$0	$0	$0	$0	($73,600)	-5.82%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-5.82%	$1,264,929	$1,191,329	($73,600)	-5.82%
50	CONTRACT DOLLAR AMOUNT	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
51	TOTAL - SALES OF ELECTRICITY	$56,883,021	$0	$53,833,272	($53,833,272)	$0	$0	$0	$56,883,021	22.34%	0.00%	65.00%	-100.00%	0.00%	0.00%	0.00%	13.25%	$391,262,318	$448,145,339	$56,883,021	14.54%
52	MISCELLANEOUS SERVICE REVENUE	($353,568)	$0	$0	$0	$0	$0	$0	($353,568)	-60.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-60.01%	$589,151	$235,583	($353,568)	-60.01%
53	FORFEITED DISCOUNT (LATE PAYMENT)	$94,521	$0	$0	$0	$0	$0	$0	$94,521	13.19%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	13.19%	$716,699	$811,220	$94,521	13.19%
54	TOTAL - MISCELLANEOUS REVENUE	($259,047)	$0	$0	$0	$0	$0	$0	($259,047)	-19.84%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-19.84%	$1,305,850	$1,046,803	($259,047)	-19.84%
55	TOTAL - SALES OF ELECTRICITY	$56,623,974	$0	$53,833,272	($53,833,272)	$0	$0	$0	$56,623,974	22.13%	0.00%	65.00%	-100.00%	0.00%	0.00%	0.00%	13.15%	$392,568,168	$449,192,142	$56,623,974	14.42%

NOTES:

*	DUPLICATE CUSTOMERS.
**	EXCLUDES DUPLICATE CUSTOMERS.
#	REVENUE BASED ON RATES EFFECTIVE 11/01/2019 FROM DOCKET E-22 SUB 562 EXCLUDING BASE FUEL.
##	BASED ON RATES EFFECTIVE 2/1/2024.
###	NON-FUEL BASE REVENUE INCLUDES PROPOSED NON-FUEL BASE REVENUE INCREASE OF $56,623,974.
####	NON-FUEL RIDER REVENUE INCLUDES PROPOSED RIDER EDIT CHARGE OF $ COMBINED WITH CURRENT NON-FUEL RIDER REVENUE ANNUALIZED WITH RATES EFFECTIVE 02/01/2024.
#####	BASED ON APPROVED BASE FUEL RATES.
@	BASED ON RIDER A RATES, RIDER B RATES, AND RIDER B1 RATES EFFECTIVE 2/1/2024.
(1)	FUEL REVENUE REFLECTS THE 5% ENERGY CONSERVATION DISCOUNT AND THE 2% DISCOUNT FOR THOSE CUSTOMERS WHOSE METERS ARE READ ON THE COMPANY'S SIDE OF THE TRANSFORMERS.

DOMINION ENERGY NORTH CAROLINA
PRESENT RATES (EFFECTIVE 11/01/19) VERSUS PROPOSED RATES WITH $56,623,974 BASE NON-FUEL INCREASE
12 MONTHS ENDED DECEMBER 31, 2023 - ADJUSTED FOR INCREASED USAGE, WEATHER, AND CUSTOMER GROWTH & EE
DOCKET NO. E-22, SUB 694

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(16)	(17)
				PRESENT ANNUALIZED REVENUE								PROPOSED REVENUE BASED ON $56,623,974 BASE NON-FUEL REVENUE INCREASE EDIT RIDERS AND FUEL REVENUE DECREASE							
LINE NO.		BOOKED 12/2023 CUST INCLUDING GROWTH THROUGH 06/30/2024	BOOKED KWH SALES INCLUDING GROWTH THROUGH	BASE NON-FUEL REVENUE #	RIDER NON-FUEL REVENUE ##	BASE FUEL REVENUE	RIDER A FUEL REVENUE ##	RIDER B FUEL REVENUE ##	RIDER B1 FUEL REVENUE ##	FUEL REVENUE (5)+(6)+(7)+(8)	TOTAL REVENUE	BASE NON-FUEL REVENUE ###	RIDER NON-FUEL REVENUE ####	BASE FUEL REVENUE #####	RIDER A FUEL REVENUE @	RIDER B FUEL REVENUE @	RIDER B1 FUEL REVENUE @	FUEL REVENUE (13)+(14)+(15)+(16)	TOTAL REVENUE
	RESIDENTIAL																		
1	SCHEDULE 1	107,612	1,504,186,279	$131,347,602	$2,743,864	$31,802,363	$20,653,518	$2,783,833	$9,455,122	$64,694,836	$198,786,302	$159,425,245	$2,743,864	$33,563,656	$0	($13,225,459)	$9,455,122	$29,793,319	$191,962,428
2	SCHEDULE 1DF (DUEL FUEL)	929 *	2,210,435	$112,983	$2,911	$46,456	$30,170	$4,067	$13,812	$94,503	$210,397	$137,135	$2,911	$49,028	$0	($19,319)	$13,812	$43,521	$183,567
3	SCHEDULE 1P (TIME-OF-USAGE)	436	13,301,314	$922,145	$20,638	$279,947	$181,807	$24,505	$83,231	$569,489	$1,512,272	$1,119,287	$20,638	$295,451	$0	($116,420)	$83,231	$262,262	$1,402,186
4	SCHEDULE 1T (TIME-OF-USAGE)	35	671,122	$57,206	$1,142	$14,033	$9,114	$1,228	$4,172	$28,548	$86,895	$69,435	$1,142	$14,810	$0	($5,836)	$4,172	$13,147	$83,724
5	SCHEDULE 1W (WATER HEATER)	15 *	111,866	$3,563	$147	$2,369	$1,539	$207	$704	$4,820	$8,530	$4,324	$147	$2,501	$0	($985)	$704	$2,220	$6,691
6	SUBTOTAL - RESIDENTIAL	108,083 **	1,520,481,017	$132,443,498	$2,768,702	$32,145,168	$20,876,147	$2,813,840	$9,557,041	$65,392,196	$200,604,396	$160,755,426	$2,768,702	$33,925,446	$0	($13,368,019)	$9,557,041	$30,114,468	$193,638,596
7	INCREASED USAGE, WEATHER & CUST GROWTH	1,714	102,282,823	$8,100,421	$186,251	$2,162,407	$1,404,339	$189,287	$642,903	$4,398,936	$12,685,607	$9,832,016	$186,251	$2,282,166	$0	($899,267)	$642,903	$2,025,802	$12,044,068
8	ENERGY REDUCTION DUE TO EE		0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	SUBTOTAL - RESIDENTIAL ADJ. FOR GROWTH	109,797 **	1,622,763,840	$140,543,919	$2,954,953	$34,307,575	$22,280,486	$3,003,128	$10,199,943	$69,791,132	$213,290,003	$170,587,442	$2,954,953	$36,207,612	$0	($14,267,286)	$10,199,943	$32,140,269	$205,682,664
	SMALL GEN SERVICE & PUBLIC AUTHORITY																		
10	SCHEDULE 5	14,801	500,603,442	$34,733,821	$1,549,506	$10,587,759	$6,884,797	$927,618	$3,057,685	$21,457,858	$57,741,185	$43,686,332	$1,549,506	$11,179,472	$0	($4,405,309)	$3,057,685	$9,831,848	$55,067,686
11	SCHEDULE 5C (COTTON GIN)	19	4,066,462	$247,376	$7,956	$86,006	$55,926	$7,535	$24,838	$174,305	$429,637	$311,200	$7,956	$90,812	$0	($35,785)	$24,838	$79,865	$399,021
12	SCHEDULE 5P (TIME-OF-USAGE)	1,057	122,853,635	$6,557,249	$262,826	$2,598,354	$1,689,606	$227,648	$750,390	$5,265,998	$12,086,074	$8,249,128	$262,826	$2,743,567	$0	($1,081,112)	$750,390	$2,412,845	$10,924,800
13	SCHEDULE 7	50 *	864,339	$50,081	$1,545	$18,281	$11,887	$1,602	$5,279	$37,049	$88,675	$63,010	$1,545	$19,302	$0	($7,606)	$5,279	$16,976	$81,531
14	SCHEDULE 30 - (PUBLIC AUTHORITY)	1,218	71,055,929	$4,746,761	$175,249	$1,502,833	$977,232	$131,667	$434,010	$3,045,741	$7,967,751	$5,980,836	$175,249	$1,586,821	$0	($625,292)	$434,010	$1,395,538	$7,551,623
15	SCHEDULE 42 - (ALL ELEC / PUB AUTH)	998	46,136,472	$2,950,042	$120,854	$975,786	$634,515	$85,491	$281,802	$1,977,594	$5,048,490	$3,711,165	$120,854	$1,030,320	$0	($406,001)	$281,802	$906,120	$4,738,140
16	SUBTOTAL - SGS & PUBLIC AUTHORITY	18,093 **	745,580,278	$49,285,329	$2,117,936	$15,769,019	$10,253,963	$1,381,560	$4,554,003	$31,958,545	$83,361,810	$62,001,672	$2,117,936	$16,650,295	$0	($6,561,105)	$4,554,003	$14,643,193	$78,762,801
17	INCREASED USAGE, WEATHER & CUST GROWTH	328	16,292,640	$997,643	$46,282	$344,589	$224,073	$30,190	$99,515	$698,368	$1,742,292	$1,255,050	$46,282	$363,847	$0	($143,375)	$99,515	$319,987	$1,621,319
18	ENERGY REDUCTION DUE TO EE		0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	SUBTOTAL - SGS & PA ADJ. FOR GROWTH	18,421 **	761,872,918	$50,282,973	$2,164,218	$16,113,608	$10,478,036	$1,411,750	$4,653,519	$32,656,913	$85,104,103	$63,256,722	$2,164,218	$17,014,142	$0	($6,704,480)	$4,653,519	$14,963,180	$80,384,120
	LARGE GEN SERVICE																		
20	SCHEDULE 6C	2	5,281,121	$222,692	$8,555	$110,798	$72,219	$9,712	$33,245	$225,974	$457,221	$270,549	$8,555	$117,415	$0	($46,268)	$33,245	$104,392	$383,495
21	SCHEDULE 6L	4	335,253,672	$13,766,991	$542,839	$6,927,737	$4,515,577	$607,250	$2,078,651	$14,129,216	$28,439,047	$16,725,605	$542,839	$7,341,486	$0	($2,892,941)	$2,078,651	$6,527,197	$23,795,641
22	SCHEDULE 6P	24	93,022,502	$4,689,959	$153,120	$1,939,813	$1,264,392	$170,034	$582,036	$3,956,276	$8,799,354	$5,697,825	$153,120	$2,055,666	$0	($810,043)	$582,036	$1,827,659	$7,678,604
23	SCHEDULE 10 0.0000%	25	138,637,609	$7,054,897	$227,441	$2,892,406	$1,885,303	$253,534	$867,860	$5,899,103	$13,181,441	$8,571,103	$227,441	$3,065,151	$0	($1,207,835)	$867,860	$2,725,176	$11,523,720
24	SCHEDULE LGS-RTP WITH CBL	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	SCHEDULE LGS-RTP WITH ED	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	SUBTOTAL - LARGE GENERAL SERVICE	55	572,194,905	25,734,539	931,955	$11,870,755	$7,737,492	$1,040,530	$3,561,792	24,210,568	50,877,062	$31,265,082	$931,955	$12,579,718	$0	($4,957,087)	$3,561,792	11,184,424	$43,381,461
27	INCREASED USAGE, WEATHER & CUST GROWTH	1	(9,480,412)	($541,649)	($15,441)	($196,681)	($128,199)	($17,240)	($59,014)	($401,133)	($958,223)	($658,054)	($15,441)	($208,427)	$0	$82,132	($59,014)	($185,309)	($858,804)
28	ENERGY REDUCTION DUE TO EE		0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	SUBTOTAL - LGS ADJ. FOR GROWTH	56	562,714,493	$25,192,890	$916,514	$11,674,074	$7,609,293	$1,023,290	$3,502,779	$23,809,436	$49,918,839	$30,607,029	$916,514	$12,371,291	$0	($4,874,955)	$3,502,779	$10,999,115	$42,522,657
30	**SCHEDULE 6VP**	3	255,486,894	$9,583,715	$800	$5,275,804	$3,427,868	$461,920	$1,556,682	$10,722,274	$20,306,789	$11,525,514	$800	$5,569,359	$0	($2,194,632)	$1,556,682	$4,931,408	$16,457,722
31	INCREASED USAGE, WEATHER & CUST GROWTH	0	6,426,584	$240,941	$20	$132,709	$86,225	$11,619	$39,157	$269,711	$510,672	$289,759	$20	$140,093	$0	($55,204)	$39,157	$124,046	$413,825
32	SUBTOTAL - 6VP ADJ. FOR GROWTH	3	261,913,478	$9,824,655	$820	$5,408,513	$3,514,093	$473,540	$1,595,839	$10,991,985	$20,817,460	$11,815,273	$820	$5,709,452	$0	($2,249,837)	$1,595,839	$5,055,454	$16,871,547
33	**SCHEDULE NS**	1	657,936,799	$19,805,302	$0	$13,395,593	$8,699,898	$1,173,101	$4,272,642	$27,541,234	$47,346,536	$23,816,866	$0	$14,139,062	$0	($5,571,409)	$4,272,642	$12,840,295	$36,657,160
34	INCREASED USAGE, WEATHER & CUST GROWTH	0	73,661,017	$2,217,354	$0	$1,499,738	$974,020	$131,338	$478,355	$3,083,450	$5,300,804	$2,666,479	$0	$1,582,975	$0	($623,761)	$478,355	$1,437,568	$4,104,047
35	SUBTOTAL - SCHEDULE NS ADJ. FOR GROWTH	1	731,597,816	$22,022,655	$0	$14,895,332	$9,673,918	$1,304,439	$4,750,996	$30,624,685	$52,647,340	$26,483,344	$0	$15,722,037	$0	($6,195,170)	$4,750,996	$14,277,863	$40,761,207
36	**TRAFFIC CONTROL**																		
37	SCHEDULE 30T - TRAFFIC CONTROL	195	465,629	$48,204	$0	$9,862	$6,405	$863	$2,828	$19,958	$68,163	$59,052	$0	$10,408	$0	($4,101)	$2,828	$9,135	$68,187
38	INCREASED USAGE, WEATHER & CUST GROWTH	1	47,870	$2,757	$0	$1,014	$658	$89	$291	$2,052	$4,809	$3,378	$0	$1,070	$0	($422)	$291	$939	$4,317
39	SUBTOTAL - 30T ADJ. FOR GROWTH	196	513,499	$50,962	$0	$10,876	$7,063	$952	$3,119	$22,010	$72,972	$62,430	$0	$11,478	$0	($4,523)	$3,119	$10,074	$72,504
	OUTDOOR LIGHTING SERVICE																		
40	SCHEDULE 26 - OUTDOOR LIGHTING	15,303 *	13,922,900	$3,403,010	$0	$294,887	$191,509	$25,813	$81,282	$593,491	$3,996,501	$4,742,848	$0	$311,219	$0	($122,633)	$81,282	$269,868	$5,012,715
41	SCHEDULE 26 - STREET & ROADWAY	1,025	7,557,364	$1,753,735	$0	$160,065	$103,952	$14,011	$44,120	$322,148	$2,075,883	$2,444,155	$0	$168,930	$0	($66,565)	$44,120	$146,484	$2,590,640
42	SUBTOTAL - OUTDOOR LIGHTING SERVICE	1,025 **	21,480,264	$5,156,744	$0	$454,952	$295,461	$39,824	$125,402	$915,639	$6,072,384	$7,187,003	$0	$480,148	$0	($189,198)	$125,402	$416,352	$7,603,355
43	INCREASED USAGE, WEATHER & CUST GROWTH	-2 *	(1,823,177)	$93,983	$0	($38,615)	($25,078)	($3,380)	($10,644)	($77,717)	$16,266	$130,985	$0	($40,753)	$0	$16,059	($10,644)	($35,339)	$95,646
44	ENERGY REDUCTION DUE TO EE		0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
45	SUBTOTAL - ODL SERVICE ADJ. FOR GROWTH	1,023 **	19,657,087	$5,250,727	$0	$416,337	$270,383	$36,444	$114,758	$837,923	$6,088,650	$7,317,988	$0	$439,395	$0	($173,140)	$114,758	$381,013	$7,699,001
46	SUBTOTAL - NUMBERED RATE SCHEDULES	129,497 **	3,961,033,131	$253,168,781	$6,036,504	$82,826,315	$53,833,272	$7,253,542	$24,820,953	$168,734,082	$427,939,367	$310,130,227	$6,036,504	$87,475,407	$0	($34,469,391)	$24,820,953	$77,826,969	$393,993,700
47	ECONOMIC DEVELOPMENT RIDER			($37,798)	$0	$0	$0	$0	$0	$0	($37,798)	($37,124)	$0	$0	$0	$0	$0	$0	($37,124)
48	LOAD MANAGEMENT CREDITS			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
49	FACILITIES CHARGES			$1,264,929	$0	$0	$0	$0	$0	$0	$1,264,929	$1,191,329	$0	$0	$0	$0	$0	$0	$1,191,329
50	CONTRACT DOLLAR AMOUNT			$206,819	$0	$0	$0	$0	$0	$0	$206,819	$206,819	$0	$0	$0	$0	$0	$0	$206,819
51	TOTAL - SALES OF ELECTRICITY	129,497 **	3,961,033,131	$254,602,731	$6,036,504	$82,826,315	$53,833,272	$7,253,542	$24,820,953	$168,734,082	$429,373,317	$311,491,251	$6,036,504	$87,475,407	$0	($34,469,391)	$24,820,953	$77,826,969	$395,354,724
52	MISCELLANEOUS SERVICE REVENUE			$589,151	$0	$0	$0	$0	$0	$0	$589,151	$235,583	$0	$0	$0	$0	$0	$0	$235,583
53	FORFEITED DISCOUNT (LATE PAYMENT)			$716,699	$0	$0	$0	$0	$0	$0	$716,699	$811,220	$0	$0	$0	$0	$0	$0	$811,220
54	TOTAL - MISCELLANEOUS REVENUE			$1,305,850	$0	$0	$0	$0	$0	$0	$1,305,850	$1,046,803	$0	$0	$0	$0	$0	$0	$1,046,803
55	TOTAL - SALES OF ELECTRICITY	129,497 **	3,961,033,131	$255,908,581	$6,036,504	$82,826,315	$53,833,272	$7,253,542	$24,820,953	$168,734,082	$430,679,167	$312,538,054	$6,036,504	$87,475,407	$0	($34,469,391)	$24,820,953	$77,826,969	$396,401,527

NOTES:
* DUPLICATE CUSTOMERS.
** EXCLUDES DUPLICATE CUSTOMERS.
# REVENUE BASED ON RATES EFFECTIVE 11/01/2019 FROM DOCKET E-22 SUB 562 EXCLUDING BASE FUEL.
BASED ON RATES EFFECTIVE 2/1/2024.
NON-FUEL BASE REVENUE INCLUDES PROPOSED NON-FUEL BASE REVENUE INCREASE OF $56,623,974.
NON-FUEL RIDER REVENUE INCLUDES PROPOSED RIDER EDIT CHARGE OF $ COMBINED WITH CURRENT NON-FUEL RIDER REVENUE ANNUALIZED WITH RATES EFFECTIVE 02/01/2024.
BASED ON APPROVED BASE FUEL RATES.
@ BASED ON RIDER A RATES, RIDER B RATES, AND RIDER B1 RATES EFFECTIVE 2/1/2024.
(1) FUEL REVENUE REFLECTS THE 5% ENERGY CONSERVATION DISCOUNT AND THE 2% DISCOUNT FOR THOSE CUSTOMERS WHOSE METERS ARE READ ON THE COMPANY'S SIDE OF THE TRANSFORMERS.

DOMINION ENERGY NORTH CAROLINA
PRESENT RATES (EFFECTIVE 11/01/19) VERSUS PROPOSED RATES WITH $ BASE NON-FUEL INCREASE
12 MONTHS ENDED DECEMBER 31, 2023 - ADJUSTED FOR INCREASED USAGE, WEATHER, AND CUSTOMER GROWTH & EE
DOCKET NO. E-22, SUB 694

	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)	(33)	(34)	(35)	(36)	(37)	(38)
		TOTAL CHANGE								PERCENTAGE CHANGE								CHANGE AND PERCENTAGE CHANGE FROM PRESENT BASE NON-FUEL, BASE FUEL, AND RIDER A			
LINE NO.		BASE NON-FUEL	RIDER NON-FUEL	BASE FUEL	RIDER A FUEL	RIDER B FUEL	RIDER B1 FUEL	TOTAL FUEL	TOTAL	BASE NON-FUEL	RIDER NON-FUEL	BASE FUEL	RIDER A FUEL	RIDER B FUEL	TOTAL B1 FUEL	TOTAL FUEL	TOTAL	PRESENT BASE NON-FUEL + BASE FUEL +	PROPOSED BASE NON-FUEL + BASE FUEL + RIDER A	CHANGE	% CHANGE
	RESIDENTIAL																				
1	SCHEDULE 1	$28,077,643	$0	$1,761,292	($20,653,518)	($16,009,292)	$0	($34,901,517)	($6,823,874)	21.38%	0.00%	5.54%	-100.00%	-575.08%	0.00%	-53.95%	-3.43%	$183,803,483	$192,988,901	$9,185,418	5.00%
2	SCHEDULE 1DF (DUEL FUEL)	$24,153	$0	$2,573	($30,170)	($23,386)	$0	($50,983)	($26,830)	21.38%	0.00%	5.54%	-100.00%	-575.08%	0.00%	-53.95%	-12.75%	$189,608	$186,164	($3,444)	-1.82%
3	SCHEDULE 1P (TIME-OF-USAGE)	$197,142	$0	$15,504	($181,807)	($140,925)	$0	($307,227)	($110,086)	21.38%	0.00%	5.54%	-100.00%	-575.08%	0.00%	-53.95%	-7.28%	$1,383,898	$1,414,737	$30,839	2.23%
4	SCHEDULE 1T (TIME-OF-USAGE)	$12,229	$0	$777	($9,114)	($7,064)	$0	($15,401)	($3,172)	21.38%	0.00%	5.54%	-100.00%	-575.08%	0.00%	-53.95%	-3.65%	$80,353	$84,246	$3,893	4.84%
5	SCHEDULE 1W (WATER HEATER)	$762	$0	$131	($1,539)	($1,193)	$0	($2,600)	($1,839)	21.38%	0.00%	5.54%	-100.00%	-575.08%	0.00%	-53.95%	-21.56%	$7,471	$6,825	($646)	-8.65%
6	SUBTOTAL - RESIDENTIAL	$28,311,928	$0	$1,780,278	($20,876,147)	($16,181,859)	$0	($35,277,728)	($6,965,800)	21.38%	0.00%	5.54%	-100.00%	-575.08%	0.00%	-53.95%	-3.47%	$185,464,812	$194,680,872	$9,216,059	4.97%
7	INCREASED USAGE, WEATHER & CUST GROWTH	$1,731,595	$0	$119,759	($1,404,339)	($1,088,554)	$0	($2,373,134)	($641,539)	21.38%	0.00%	5.54%	-100.00%	-575.08%	0.00%	-53.95%	-5.06%	$11,667,167	$12,114,182	$447,015	3.83%
8	ENERGY REDUCTION DUE TO EE	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	0.00%
9	SUBTOTAL - RESIDENTIAL ADJ. FOR GROWTH	$30,043,524	$0	$1,900,037	($22,280,486)	($17,270,414)	$0	($37,650,862)	($7,607,339)	21.38%	0.00%	5.54%	-100.00%	-575.08%	0.00%	-53.95%	-3.57%	$197,131,979	$206,795,054	$9,663,075	4.90%
	SMALL GEN SERVICE & PUBLIC AUTHORITY																				
10	SCHEDULE 5	$8,952,511	$0	$591,713	($6,884,797)	($5,332,926)	$0	($11,626,010)	($2,673,499)	25.77%	0.00%	5.59%	-100.00%	-574.91%	0.00%	-54.18%	-4.63%	$52,206,376	$54,865,803	$2,659,428	5.09%
11	SCHEDULE 5C (COTTON GIN)	$63,824	$0	$4,807	($55,926)	($43,320)	$0	($94,440)	($30,616)	25.80%	0.00%	5.59%	-100.00%	-574.91%	0.00%	-54.18%	-7.13%	$389,308	$402,012	$12,704	3.26%
12	SCHEDULE 5P (TIME-OF-USAGE)	$1,691,879	$0	$145,213	($1,689,606)	($1,308,760)	$0	($2,853,153)	($1,161,274)	25.80%	0.00%	5.59%	-100.00%	-574.91%	0.00%	-54.18%	-9.61%	$10,845,209	$10,992,696	$147,486	1.36%
13	SCHEDULE 7	$12,930	$0	$1,022	($11,887)	($9,208)	$0	($20,073)	($7,144)	25.82%	0.00%	5.59%	-100.00%	-574.91%	0.00%	-54.18%	-8.06%	$80,249	$82,313	$2,064	2.57%
14	SCHEDULE 30 - (PUBLIC AUTHORITY)	$1,234,075	$0	$83,988	($977,232)	($756,959)	$0	($1,650,203)	($416,128)	26.00%	0.00%	5.59%	-100.00%	-574.91%	0.00%	-54.18%	-5.22%	$7,226,826	$7,567,657	$340,831	4.72%
15	SCHEDULE 42 - (ALL ELEC / PUB AUTH)	$761,124	$0	$54,533	($634,515)	($491,492)	$0	($1,071,473)	($310,350)	25.80%	0.00%	5.59%	-100.00%	-574.91%	0.00%	-54.18%	-6.15%	$4,560,343	$4,741,485	$181,142	3.97%
16	SUBTOTAL - SGS & PUBLIC AUTHORITY	$12,716,343	$0	$881,276	($10,253,963)	($7,942,665)	$0	($17,315,352)	($4,599,009)	25.80%	0.00%	5.59%	-100.00%	-574.91%	0.00%	-54.18%	-5.52%	$75,308,311	$78,651,967	$3,343,655	4.44%
17	INCREASED USAGE, WEATHER & CUST GROWTH	$257,407	$0	$19,258	($224,073)	($173,565)	$0	($378,380)	($120,974)	25.80%	0.00%	5.59%	-100.00%	-574.91%	0.00%	-54.18%	-6.94%	$1,566,305	$1,618,897	$52,592	3.36%
18	ENERGY REDUCTION DUE TO EE	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	0.00%
19	SUBTOTAL - SGS & PA ADJ. FOR GROWTH	$12,973,749	$0	$900,534	($10,478,036)	($8,116,230)	$0	($17,693,732)	($4,719,983)	25.80%	0.00%	5.59%	-100.00%	-574.91%	0.00%	-54.18%	-5.55%	$76,874,616	$80,270,863	$3,396,247	4.42%
	LARGE GEN SERVICE																				
20	SCHEDULE 6C	$47,857	$0	$6,617	($72,219)	($55,980)	$0	($121,582)	($73,725)	21.49%	0.00%	5.97%	-100.00%	-576.40%	0.00%	-53.80%	-16.12%	$405,709	$387,964	($17,745)	-4.37%
21	SCHEDULE 6L	$2,958,614	$0	$413,749	($4,515,577)	($3,500,191)	$0	($7,602,020)	($4,643,406)	21.49%	0.00%	5.97%	-100.00%	-576.40%	0.00%	-53.80%	-16.33%	$25,210,306	$24,067,092	($1,143,214)	-4.53%
22	SCHEDULE 6P	$1,007,867	$0	$115,853	($1,264,392)	($980,077)	$0	($2,128,617)	($1,120,750)	21.49%	0.00%	5.97%	-100.00%	-576.40%	0.00%	-53.80%	-12.74%	$7,894,164	$7,753,491	($140,673)	-1.78%
23	SCHEDULE 10	$1,516,206	$0	$172,745	($1,885,303)	($1,461,368)	$0	($3,173,927)	($1,657,721)	21.49%	0.00%	5.97%	-100.00%	-576.40%	0.00%	-53.80%	-12.58%	$11,832,607	$11,636,254	($196,352)	-1.66%
24	SCHEDULE LGS-RTP WITH CBL	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	0.00%
25	SCHEDULE LGS-RTP WITH ED	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	0.00%
26	SUBTOTAL - LARGE GENERAL SERVICE	$5,530,543	$0	$708,964	($7,737,492)	($5,997,617)	$0	($13,026,145)	($7,495,601)	21.49%	0.00%	5.97%	-100.00%	-576.40%	0.00%	-53.80%	-14.73%	$45,342,785	$43,844,801	($1,497,984)	-3.30%
27	INCREASED USAGE, WEATHER & CUST GROWTH	($116,404)	$0	($11,746)	$128,199	$99,372	$0	$215,824	$99,419	21.49%	0.00%	5.97%	-100.00%	-576.40%	0.00%	-53.80%	-10.38%	($866,529)	($866,481)	$48	-0.01%
28	ENERGY REDUCTION DUE TO EE	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	0.00%
29	SUBTOTAL - LGS ADJ. FOR GROWTH	$5,414,139	$0	$697,217	($7,609,293)	($5,898,245)	$0	($12,810,321)	($7,396,182)	21.49%	0.00%	5.97%	-100.00%	-576.40%	0.00%	-53.80%	-14.82%	$44,476,257	$42,978,320	($1,497,937)	-3.37%
30	SCHEDULE 6VP	$1,941,799	$0	$293,554	($3,427,868)	($2,656,553)	$0	($5,790,866)	($3,849,067)	20.26%	0.00%	5.56%	-100.00%	-575.11%	0.00%	-54.01%	-18.95%	$18,287,387	$17,094,873	($1,192,514)	-6.52%
31	INCREASED USAGE, WEATHER & CUST GROWTH	$48,818	$0	$7,384	($86,225)	($66,824)	$0	($145,665)	($96,847)	20.26%	0.00%	5.56%	-100.00%	-575.11%	0.00%	-54.01%	-18.96%	$459,875	$429,852	($30,023)	-6.53%
32	SUBTOTAL - 6VP ADJ. FOR GROWTH	$1,990,617	$0	$300,939	($3,514,093)	($2,723,376)	$0	($5,936,531)	($3,945,913)	20.26%	0.00%	5.56%	-100.00%	-575.11%	0.00%	-54.01%	-18.95%	$18,747,262	$17,524,725	($1,222,537)	-6.52%
33	SCHEDULE NS	$4,011,564	$0	$743,469	($8,699,898)	($6,744,510)	$0	($14,700,940)	($10,689,376)	20.26%	0.00%	5.55%	-100.00%	-574.93%	0.00%	-53.38%	-22.58%	$41,900,793	$37,955,927	($3,944,866)	-9.41%
34	INCREASED USAGE, WEATHER & CUST GROWTH	$449,125	$0	$83,237	($974,020)	($755,099)	$0	($1,645,882)	($1,196,757)	20.26%	0.00%	5.55%	-100.00%	-574.93%	0.00%	-53.38%	-22.58%	$4,691,112	$4,249,454	($441,658)	-9.41%
35	SUBTOTAL - SCHEDULE NS ADJ. FOR GROWTH	$4,460,689	$0	$826,706	($9,673,918)	($7,499,609)	$0	($16,346,822)	($11,886,133)	20.26%	0.00%	5.55%	-100.00%	-574.93%	0.00%	-53.38%	-22.58%	$46,591,905	$42,205,381	($4,386,523)	-9.41%
	TRAFFIC CONTROL																				
37	SCHEDULE 30T - TRAFFIC CONTROL	$10,847	$0	$546	($6,405)	($4,965)	$0	($10,823)	$24	22.50%	0.00%	5.54%	-100.00%	-575.08%	0.00%	-54.23%	0.04%	$64,471	$69,460	$4,989	7.74%
38	INCREASED USAGE, WEATHER & CUST GROWTH	$620	$0	$56	($658)	($510)	$0	($1,113)	($492)	22.50%	0.00%	5.54%	-100.00%	-575.08%	0.00%	-54.23%	-10.23%	$4,430	$4,448	$18	0.41%
39	SUBTOTAL - 30T ADJ. FOR GROWTH	$11,468	$0	$602	($7,063)	($5,475)	$0	($11,936)	($468)	22.50%	0.00%	5.54%	-100.00%	-575.08%	0.00%	-54.23%	-0.64%	$68,901	$73,908	$5,007	7.27%
	OUTDOOR LIGHTING SERVICE																				
40	SCHEDULE 26 - OUTDOOR LIGHTING	$1,339,838	$0	$16,332	($191,509)	($148,446)	$0	($323,624)	$1,016,214	39.37%	0.00%	5.54%	-100.00%	-575.08%	0.00%	-54.53%	25.43%	$3,889,406	$5,054,066	$1,164,660	29.94%
41	SCHEDULE 26 - STREET & ROADWAY	$690,421	$0	$8,865	($103,952)	($80,577)	$0	($175,663)	$514,757	39.37%	0.00%	5.54%	-100.00%	-575.08%	0.00%	-54.53%	24.80%	$2,017,751	$2,613,085	$595,334	29.50%
42	SUBTOTAL - OUTDOOR LIGHTING SERVICE	$2,030,258	$0	$25,196	($295,461)	($229,023)	$0	($499,287)	$1,530,971	39.37%	0.00%	5.54%	-100.00%	-575.08%	0.00%	-54.53%	25.21%	$5,907,157	$7,667,151	$1,759,994	29.79%
43	INCREASED USAGE, WEATHER & CUST GROWTH	$37,002	$0	($2,139)	$25,078	$19,439	$0	$42,378	$79,380	39.37%	0.00%	5.54%	-100.00%	-575.08%	0.00%	-54.53%	488.00%	$30,290	$90,231	$59,941	197.89%
44	ENERGY REDUCTION DUE TO EE	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	0.00%
45	SUBTOTAL - ODL SERVICE ADJ. FOR GROWTH	$2,067,260	$0	$23,058	($270,383)	($209,584)	$0	($456,909)	$1,610,351	39.37%	0.00%	5.54%	-100.00%	-575.08%	0.00%	-54.53%	26.45%	$5,937,448	$7,757,383	$1,819,935	30.65%
46	SUBTOTAL - NUMBERED RATE SCHEDULES	$56,961,447	$0	$4,649,092	($53,833,272)	($41,722,933)	$0	($90,907,113)	($33,945,667)	22.50%	0.00%	5.61%	-100.00%	-575.21%	0.00%	-53.88%	-7.93%	$389,828,367	$397,605,634	$7,777,267	2.00%
47	ECONOMIC DEVELOPMENT RIDER (2)	$674	$0	$0	$0	$0	$0	$0	$674	-1.78%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-1.78%	($37,798)	($37,124)	$674	-1.78%
48	LOAD MANAGEMENT CREDITS	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	0.00%
49	FACILITIES CHARGES	($73,600)	$0	$0	$0	$0	$0	$0	($73,600)	-5.82%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-5.82%	$1,264,929	$1,191,329	($73,600)	-5.82%
50	CONTRACT DOLLAR AMOUNT	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
51	TOTAL - SALES OF ELECTRICITY	$56,888,520	$0	$4,649,092	($53,833,272)	($41,722,933)	$0	($90,907,113)	($34,018,593)	22.34%	0.00%	5.61%	-100.00%	-575.21%	0.00%	-53.88%	-7.92%	$391,262,318	$398,966,658	$7,704,340	1.97%
52	MISCELLANEOUS SERVICE REVENUE	($353,568)	$0	$0	$0	$0	$0	$0	($353,568)	-60.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-60.01%	$589,151	$235,583	($353,568)	-60.01%
53	FORFEITED DISCOUNT (LATE PAYMENT)	$94,521	$0	$0	$0	$0	$0	$0	$94,521	13.19%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	13.19%	$716,699	$811,220	$94,521	13.19%
54	TOTAL - MISCELLANEOUS REVENUE	($259,047)	$0	$0	$0	$0	$0	$0	($259,047)	-19.84%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-19.84%	$1,305,850	$1,046,803	($259,047)	-19.84%
55	TOTAL - SALES OF ELECTRICITY (2)	$56,629,473	$0	$4,649,092	($53,833,272)	($41,722,933)	$0	($90,907,113)	($34,277,640)	22.13%	0.00%	5.61%	-100.00%	-575.21%	0.00%	-53.88%	-7.96%	$392,568,168	$400,013,461	$7,445,293	1.90%

NOTES:

*	DUPLICATE CUSTOMERS.
**	EXCLUDES DUPLICATE CUSTOMERS.
#	REVENUE BASED ON RATES EFFECTIVE 11/01/2019 FROM DOCKET E-22 SUB 562 EXCLUDING BASE FUEL.
##	BASED ON RATES EFFECTIVE 2/1/2024.
###	NON-FUEL BASE REVENUE INCLUDES PROPOSED NON-FUEL BASE REVENUE INCREASE OF $56,623,974.
####	NON-FUEL RIDER REVENUE INCLUDES PROPOSED RIDER EDIT CHARGE OF $ COMBINED WITH CURRENT NON-FUEL RIDER REVENUE ANNUALIZED WITH RATES EFFECTIVE 02/01/2024.
#####	BASED ON APPROVED BASE FUEL RATES.
@	BASED ON RIDER A RATES, RIDER B RATES, AND RIDER B1 RATES EFFECTIVE 2/1/2024.
(1)	FUEL REVENUE REFLECTS THE 5% ENERGY CONSERVATION DISCOUNT AND THE 2% DISCOUNT FOR THOSE CUSTOMERS WHOSE METERS ARE READ ON THE COMPANY'S SIDE OF THE TRANSFORMERS.
(2)	RIDER EDR APPLIES TO THE SUM OF CHARGES IN THE TARIFF, EXCLUDING ALL APPLICABLE RIDERS, PLUS FUEL RIDER A. WHEN PROJECTED FUEL, INCLUDING THE FUEL BASE DECREASES, THE RIDER EDR DISCOUNT CHANGES. THE COMPANY HAS NOT CHANGED THE RATE DESIGN TO BALANCE BACK TO THE REVENUE REQUIREMENT INCREASE TO ACCOUNT FOR A REDUCTION IN PROJECTED FUEL.

DOMINION ENERGY NORTH CAROLINA
SCHEDULE SGS-EV DERIVATION OF PROPOSED RATES
12 MONTHS ENDED DECEMBER 31, 2023
DOCKET NO. E-22, SUB 694

SCH SGS-EV IS DESIGNED TO BE REVENUE NEUTRAL WITH SCHEDULES 5 AND 30

THE FOLLOWING EXHIBIT IS PROOF OF REVENUE THAT THE NEW SCH SGS-EV HAS BEEN DESIGNED TO BE REVENUE NEUTRAL WITH SCH 5 & 30

		(1)	(2)	(3)	(4)	(5)
Study Units		RATE DESIGN UNITS 12/31/2023	PROPOSED BASIC RATES	PROPOSED BASIC REVENUE (1) X (2)	TOTAL RATE WITH PROPOSED BASE FUEL $0.034903	TOTAL RATE WITH PROPOSED TOTAL FUEL $0.042864
	NON DEMAND BILLING					
151,178	BASIC CUSTOMER CHARGE	152,064	$22.88	$3,478,458	$22.88	$22.88
	KW DEMAND					
208,531	ALL KW PEAK	206,011	$0.000	$0	$0.000	$0.000
542,842	ALL KW BASE	536,281	$0.000	$0	$0.000	$0.000
11,713	ALL EXCESS KW DEMAND	11,571	$2.164	$25,041	$2.164	$2.164
	ENERGY - NO DISCOUNT					
40,782,802	ALL KWHS - PEAK MONTHS	40,289,917	$0.090045	$3,627,906	$0.124948	$0.132909
99,745,719	ALL KWHS - BASE MONTHS	98,540,230	$0.080637	$7,945,989	$0.115540	$0.123501
	ENERGY - 2% DISCOUNT					
1,968	ALL KWHS - PEAK MONTHS	1,944	$0.088244	$172	$0.122449	$0.130251
7,467	ALL KWHS - BASE MONTHS	7,377	$0.079024	$583	$0.113229	$0.121031
	DEMAND MINIMUM					
349	MINIMUM BILLS	345	$0.000	$0	$0.000	$0.000
12,158	MINIMUM BILLED DEMAND - PEAK MONTHS	12,011	$7.213	$86,634	$7.213	$7.213
29,824	MINIMUM BILLED DEMAND - BASE MONTHS	29,464	$2.968	$87,448	$2.968	$2.968
471,626	KWH IN MINIMUM	465,926	$0.00	$0	$0.034903	$0.042864
141,009,583	SUBTOTAL - NON-DEMAND BILLING	139,305,394		$15,252,229		
	DEMAND BILLING					
43,628	BASIC CUSTOMER CHARGE	43,883	$22.88	$1,003,830	$22.88	$22.88
	KW DEMAND					
487,644	ALL KW PEAK	481,751	$11.380	$5,482,321	$11.380	$11.380
728,011	ALL KW BASE	719,213	$8.934	$6,425,445	$8.934	$8.934
67,707	ALL EXCESS KW DEMAND	66,889	$2.164	$144,747	$2.164	$2.164
	ENERGY - NO DISCOUNT					
186,780,223	FIRST 150 KWH PER KW	184,522,867	$0.066636	$12,295,866	$0.101539	$0.109500
160,478,533	NEXT 150 KWH PER KW	158,539,050	$0.039463	$6,256,427	$0.074366	$0.082327
67,942,220	NEXT 150 KWH PER KW	67,121,096	$0.033783	$2,267,552	$0.068686	$0.076647
22,442,192	ADD'L KWH	22,170,964	$0.024300	$538,752	$0.059203	$0.067164
	ENERGY - 2% DISCOUNT					
0	FIRST 150 KWH PER KW	0	$0.065303	$0	$0.099508	$0.107310
0	NEXT 150 KWH PER KW	0	$0.038674	$0	$0.072879	$0.080680
0	NEXT 150 KWH PER KW	0	$0.033107	$0	$0.067312	$0.075114
0	ADD'L KWH	0	$0.023814	$0	$0.058019	$0.065821
437,643,168	SUBTOTAL - DEMAND BILLING	432,353,977		$34,414,939		
578,652,751	TOTAL STUDY - DEMAND & ND BILLING	571,659,371		$49,667,168		
571,659,371	BOOKED SALES FOR SCH 5/30					
0.9879143746	BOOKED TO STUDY RATIO					

THE FOLLOWING IS THE ITEM 39.C RATE DESIGN FOR PROPOSED NEW SCHEDULE SGS-EV

Study Units		RATE DESIGN UNITS 12/31/2023	PROPOSED BASIC RATES	PROPOSED BASIC REVENUE (1) X (2)	TOTAL RATE WITH PROPOSED BASE FUEL $0.034903	TOTAL RATE WITH PROPOSED TOTAL FUEL $0.042864
	NON DEMAND BILLING					
0	BASIC CUSTOMER CHARGE	0	$22.88	$0	$22.88	$22.88
	KW DEMAND					
0	ALL KW PEAK	0	$0.000	$0	$0.000	$0.000
0	ALL KW BASE	0	$0.000	$0	$0.000	$0.000
0	ALL EXCESS KW DEMAND	0	$2.164	$0	$2.164	$2.164
	ENERGY - NO DISCOUNT					
0	ALL KWHS - PEAK MONTHS	0	$0.090045	$0	$0.124948	$0.132909
0	ALL KWHS - BASE MONTHS	0	$0.080637	$0	$0.115540	$0.123501
	ENERGY - 2% DISCOUNT					
0	ALL KWHS - PEAK MONTHS	0	$0.088244	$0	$0.122449	$0.130251
0	ALL KWHS - BASE MONTHS	0	$0.079024	$0	$0.113229	$0.121031
	DEMAND MINIMUM					
0	MINIMUM BILLS	0	$0.000	$0	$0.000	$0.000
0	MINIMUM BILLED DEMAND - PEAK MONTHS	0	$7.213	$0	$7.213	$7.213
0	MINIMUM BILLED DEMAND - BASE MONTHS	0	$2.968	$0	$2.968	$2.968
0	KWH IN MINIMUM	0	$0.00	$0	$0.034903	$0.042864
0	SUBTOTAL - NON-DEMAND BILLING	0		$0		
	DEMAND BILLING					
0	BASIC CUSTOMER CHARGE	0	$22.88	$0	$22.88	$22.88
	KW DEMAND					
0	ALL KW PEAK	0	$11.380	$0	$11.380	$11.380
0	ALL KW BASE	0	$8.934	$0	$8.934	$8.934
0	ALL EXCESS KW DEMAND	0	$2.164	$0	$2.164	$2.164
	ENERGY - NO DISCOUNT					
0	FIRST 150 KWH PER KW	0	$0.066636	$0	$0.101539	$0.109500
0	NEXT 150 KWH PER KW	0	$0.039463	$0	$0.074366	$0.082327
0	NEXT 150 KWH PER KW	0	$0.033783	$0	$0.068686	$0.076647
0	ADD'L KWH	0	$0.024300	$0	$0.059203	$0.067164
	ENERGY - 2% DISCOUNT					
0	FIRST 150 KWH PER KW	0	$0.065303	$0	$0.099508	$0.107310
0	NEXT 150 KWH PER KW	0	$0.038674	$0	$0.072879	$0.080680
0	NEXT 150 KWH PER KW	0	$0.033107	$0	$0.067312	$0.075114
0	ADD'L KWH	0	$0.023814	$0	$0.058019	$0.065821
437,643,168	SUBTOTAL - DEMAND BILLING	0		$0		
578,652,751	TOTAL STUDY - DEMAND & ND BILLING	0		$0		
571,659,371	BOOKED SALES FOR SCH 5/30					
0.9879143746	BOOKED TO STUDY RATIO					

TYPICAL BILL SUMMARY

TOTAL PROPOSED BILL COMPARISON
NEW SGS-EV to NC SCHEDULE 5

KW	KWH	Load Factor	SCH 5	SGS-EV	DIFFERENCE	% DIFF
30	4,500	21%	$612.38	$603.97	($8.41)	-1.37%
30	5,400	25%	$729.51	$719.55	($9.96)	-1.37%
30	6,264	29%	$841.94	$967.70	$125.76	14.94%
30	7,560	35%	$995.78	$1,076.72	$80.94	8.13%
30	9,000	42%	$1,145.09	$1,197.84	$52.75	4.61%
30	10,800	50%	$1,331.72	$1,339.02	$7.30	0.55%
30	11,880	55%	$1,443.69	$1,423.73	($19.96)	-1.38%
30	13,608	63%	$1,622.86	$1,558.23	($64.63)	-3.98%
30	15,000	69%	$1,767.20	$1,654.22	($112.98)	-6.39%
50	7,500	21%	$1,002.79	$989.24	($13.55)	-1.35%
50	9,000	25%	$1,198.00	$1,181.88	($16.12)	-1.35%
50	10,440	29%	$1,347.30	$1,595.48	$248.18	18.42%
50	12,600	35%	$1,571.25	$1,777.16	$205.91	13.10%
50	15,000	42%	$1,820.10	$1,979.04	$158.94	8.73%
50	18,000	50%	$2,131.15	$2,214.34	$83.19	3.90%
50	19,800	55%	$2,317.78	$2,355.52	$37.74	1.63%
50	22,680	63%	$2,616.39	$2,579.70	($36.69)	-1.40%
50	25,000	69%	$2,856.94	$2,739.67	($117.27)	-4.10%
100	15,000	21%	$1,952.37	$1,952.43	$0.06	0.00%
100	18,000	25%	$2,263.42	$2,337.70	$74.28	3.28%
100	20,880	29%	$2,562.02	$3,164.88	$602.86	23.53%
100	25,200	35%	$3,009.94	$3,528.26	$518.32	17.22%
100	30,000	42%	$3,507.61	$3,932.01	$424.40	12.10%
100	36,000	50%	$4,129.72	$4,402.62	$272.90	6.61%
100	39,600	55%	$4,502.97	$4,684.98	$182.01	4.04%
100	45,360	63%	$5,100.19	$5,133.35	$33.16	0.65%
100	50,000	69%	$5,581.28	$5,453.28	($128.00)	-2.29%
150	22,500	21%	$3,080.81	$2,915.60	($165.21)	-5.36%
150	27,000	25%	$3,547.38	$3,493.51	($53.87)	-1.52%
150	31,320	29%	$3,995.29	$4,734.30	$739.01	18.50%
150	37,800	35%	$4,667.16	$5,279.36	$612.20	13.12%
150	45,000	42%	$5,413.69	$5,884.99	$471.30	8.71%
150	54,000	50%	$6,346.83	$6,590.89	$244.06	3.85%
150	59,400	55%	$6,906.72	$7,014.44	$107.72	1.56%
150	68,040	63%	$7,802.55	$7,686.99	($115.56)	-1.48%
150	75,000	69%	$8,524.19	$8,166.89	($357.30)	-4.19%
250	37,500	21%	$5,337.69	$4,841.96	($495.73)	-9.29%
250	45,000	25%	$6,115.32	$5,805.15	($310.17)	-5.07%
250	52,200	29%	$6,861.83	$7,873.13	$1,011.30	14.74%
250	63,000	35%	$7,981.61	$8,781.56	$799.95	10.02%
250	75,000	42%	$9,225.82	$9,790.93	$565.11	6.13%
250	90,000	50%	$10,781.06	$10,967.44	$186.38	1.73%
250	99,000	55%	$11,714.21	$11,673.34	($40.87)	-0.35%
250	113,400	63%	$13,207.25	$12,794.25	($413.00)	-3.13%
250	125,000	69%	$14,409.99	$13,594.09	($815.90)	-5.66%
450	67,500	21%	$9,851.45	$8,694.68	($1,156.77)	-11.74%
450	81,000	25%	$11,251.18	$10,428.41	($822.77)	-7.31%
450	93,960	29%	$12,594.91	$14,150.78	$1,555.87	12.35%
450	113,400	35%	$14,610.52	$15,785.96	$1,175.44	8.05%
450	135,000	42%	$16,850.09	$17,602.83	$752.74	4.47%
450	162,000	50%	$19,649.53	$19,720.54	$71.01	0.36%
450	178,200	55%	$21,329.20	$20,991.18	($338.02)	-1.58%
450	204,120	63%	$24,016.67	$23,008.82	($1,007.85)	-4.20%
450	225,000	69%	$26,181.59	$24,448.52	($1,733.07)	-6.62%

SECTION I

DEFINITIONS

The proposed changes are as follows:

Section I.1. To define “AMI Opt-Out Customer”.

Section I.8. & I.9. To adjust formatting.

SECTION IV

SERVICE CONNECTIONS

The proposed changes are:

Section IV.B. To update service connection charge.

Section IV.F.3. To update percentages for Excess Distribution, Substation and Transmission Facilities charges, showing the percentages three places past the decimal.

Section IV.F.3.d. To delete section because it is no longer applicable, and there are no current or proposed revenues associated with these rates.

Section IV.F.4. To delete section because it is redundant information that is stated in subparagraph F.3.

SECTION V

LOCATION OF COMPANY’S EQUIPMENT

The purpose of the change to Section V is to provide additional protection against customers constructing decks and additions to their building, which impedes the Company’s ability to maintain underground secondary conductors and overhead service entrance cable.

The proposed changes are:

Section V.B. To add language to include the Customer will also provide suitable space for ongoing operations and maintenance of the necessary Company facilities.

Section V.B.1. To add "for metering apparatus" to clarify what should be free from vibration.

Section V.B.2. To add "meter" to define the outside location.

Section V.B.3. To add language to include the ongoing operation and maintenance of all Company facilities and to include reading, testing, and servicing of the meter.

Section V.B.4. To add "The metering" to define the apparatus.

SECTION IX

DEPOSITS

The purpose of the change is to allow for interest to be applied automatically.

The proposed changes are:

Section IX.D. To remove language "Upon request from the Customer, the Company will pay accrued interest annually either by direct refund or credit to the Customer's account" and replace it with "The Company will automatically apply accrued interest annually to the Customer's account".

SECTION X

BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES

The purpose of the change is to update pricing and add AMI Opt-Out.

The proposed changes are:

Section X.H. To update charges listed in the "Interval Metering Service Options Installation and Removal Charges for Interval Meters" and "Installation and Removal Charges for Contact Closures (for kW Data Only)" tables.

Section X.I. To add Smart Meter Opt-Out including:

- Information on the process to opt-out of the Smart Meter Installation and Program;
- List of conditions to be met to enroll in the Smart Meter Opt-Out Program;
- Monthly Non-communicating Metering Service Charge.

SECTION XVI

DISCONTINUANCE OF THE SUPPLY OF ELECTRICITY

The purpose of the change is to add language to address the limits to when residential disconnections for non-payment occur.

The proposed changes are:

Section XVI.B.1. To add "Residential" disconnections for non-payment shall not be worked:

a. When the temperature is forecasted to be 95 degrees Fahrenheit or higher within the 24-hour period prior to the scheduled disconnect.

b. When the temperature is forecasted to be 32 degrees Fahrenheit or lower within the 24-hour period prior to the scheduled disconnect.

c. On Fridays, weekends, Federal holidays, or on a business day prior to a Federal holiday.

SECTION XVII

RECONNECTION OF ELECTRIC SERVICE

The purpose of the change is to update pricing for service reconnection charges. The proposed changes are:

Section XVII.D. To redefine the service charges for reconnection of the supply of electricity.

Such charges are defined as:

- Residential Customers with a communicating meter
- Residential Customer with a non-communicating meter
- Nonresidential Customers

SECTION XIX

TESTING FACILITIES AND EQUIPMENT

The purpose of the change is to update language based on the type of equipment that is currently being used.

The proposed changes are:

Section XIX.C. To remove “voltmeters” and “ammeters”.

To change “insure” to “ensure”.

SECTION XXI

METER TESTS REQUESTED BY CUSTOMER

The purpose of the change is to update deposit amounts for meter testing.

The proposed changes are:

Section XXI.A. To update deposit amounts for single and poly-phase meter testing.

SECTION XXII

ELECTRIC LINE EXTENSIONS AND INSTALLATIONS

The purpose of the change is to update the provision of service to residential customers, update the residential revenue credit allowance, to update the provision of service to nonresidential customers, and to redefine the process for service upgrades and conversions.

The proposed changes are:

Section XXII.B. To define "Adequacy".

To update the definition for "Approach Lines".

To define "Permanent Residence".

Changes the "prior to" development date to the effective date of the adoption of these proposed changes.

To define "Service Characteristics".

Section XXII.C. To add a new section for "New Residential" and outline the process for "Single-Phase Not Within a Residential Development" and the process for "Single-Phase Within a New Residential Development". Single-phase residential customers and new residential subdivisions have revenue credits applied toward their line extension, and they pay the remainder in CIAC. Revenue credit allowances are updated.

Section XXII.D. To define Paragraph D as "New Nonresidential and New Residential Three-Phase Service". To update the process to serve nonresidential and three-phase residential customers.

Section XXII.G. To clarify the requirements for three-phase service.

Section XXII.H. To replace existing inadequate residential overhead service with adequate overhead service at no charge and replace inadequate underground residential service at no charge provided we can use normal trenching.

Section XXII.I. To define the process when a customer requests to convert existing overhead service to underground.

Section XXII.M. To remove "written" not to limit the type of communication methods available to the Customer.

SECTION XXIII

TEMPORARY SERVICE

The purpose of the change is to update the flat charges for temporary services upon Customer request in subsection C.

SECTION XXV

NET METERING

The purpose of the change is to reduce the potential for administrative T&C updates in the future should an address change or alternative methodologies develop for submitting a Net Metering request.

The proposed changes are:

Section XXV.B. To remove the physical address to send Interconnection Request. Instructions for submitting a request are provided on the Company's Net Metering website.

AGREEMENT FOR THE PURCHASE OF ELECTRICITY

The purpose of the change is to clarify and align with new processes.

The proposed changes are:

First – Paragraph	To replace the option to enter a "no later than date" for electricity and replace it with "at a date agreed upon by the Customer and the Company".
Fourth – Paragraph	To add "Likewise, the execution of this Agreement is a prerequisite for the installation of electric service. In the event the Customer is unable to sign the Agreement, then the installation of electric service may be canceled or delayed". This explains that failure or delaying signing of the agreement may result in cancellation or delay of the project.
Signature Area	To delete "Mail Bill To:" which will remove the chance for errors in billing the customer. The mailing address is entered into our billing system by the Design or Customer Service organization during a process outside of the agreement process; and To reword the second part of the signature area to clarify when the billing parameters will begin.

Rider D - Tax Effect Recovery (TERF)	Current	Proposed	% Change
TERF Rate Applied to Total Payment Amount	1.15226	1.15877	0.56%

Miscellaneous Charges	Current	Proposed	% Change
Section IV - Service Connections			
Connect Charge	$ 37.66	$ 17.32	-54.01%
Section X - Billing and Re-billing of Metered and Unmetered Services			
AMI Opt-Out Monthly Fee	$ 0.00	$ 30.88	0.00%
Installation and Removal Charges for Interval Meters			
Single-phase, 240 Volt, 3 wire, class 200 Installation	$ 271.50	$ 323.07	18.99%
Single-phase, 240 Volt, 3 wire, class 320 Installation	$ 216.48	$ 333.22	53.93%
Single-phase, 240 Volt, 3 wire, class 400 Installation	$ 787.70	$ 333.22	-57.70%
Three-phase, 120 Volt, 4 wire, class 200 and 320 Installation	$ 0.00	$ 441.41	0.00%
Three-phase, 120 Volt, 4 wire, class 400 Installation	$ 0.00	$ 441.41	0.00%
Three-phase, 120 Volt, 4 wire, class 10 and 20 Installation	$ 233.79	$ 422.73	80.82%
Single-phase, 240 Volt, 3 wire, class 200 Removal	$ 62.38	$ 195.51	213.42%
Single-phase, 240 Volt, 3 wire, class 320 Removal	$ 62.38	$ 195.51	213.42%
Single-phase, 240 Volt, 3 wire, class 400 Removal	$ 143.75	$ 195.51	36.01%
Three-phase, 120 Volt, 4 wire, class 200 and 320 Removal	$ 0.00	$ 279.30	0.00%
Three-phase, 120 Volt, 4 wire, class 400 Removal	$ 0.00	$ 279.30	0.00%
Three-phase, 120 Volt, 4 wire, class 10 and 20 Removal	$ 143.75	$ 279.30	94.30%
Installation and Removal Charges for Contact Closures			
One Circuit Installation	$ 203.77	$ 424.53	108.34%
Additional Curcuit Installation	$ 122.40	$ 327.98	167.96%
One Circuit Removal	$ 108.49	$ 307.23	183.19%
Additional Circuit Removal	$ 27.12	$ 223.44	723.89%
Section XII - Payments			
Returned Check Charge	$ 13.33	$ 13.33	0.00%
Section XIV - Customer Responsibility			
Trouble Call Charge	$ 0.00	$ 0.00	0.00%
Section XVII - Reconnection of Electric Service			
Reconnect Charge - Normal Hours Residential	$ 34.76	$ 7.08	-79.63%
Reconnect Charge - After Normal Hours Residential	$ 125.68	$ 7.08	-94.37%
Reconnect Charge - Normal Hours Non-Residential	$ 34.76	$ 38.52	10.82%
Reconnect Charge - After Normal Hours Non-Residential	$ 125.68	$ 38.52	-69.35%
Service Reconnection Charge - AMI Opt-Out	$ 0.00	$ 34.49	0.00%
Section XXI - Meter Tests Requested by Customer			
Single-Phase Meter Charge	$ 60.40	$ 55.86	-7.52%
Poly-Phase Meter Charge	$ 120.80	$ 111.72	-7.52%
Section XXIII - Temporary Service			
Overhead Charge	$ 460.03	$ 484.69	5.36%
Underground from Transformer Charge	$ 303.12	$ 319.51	5.41%
Underground from Stub-up Charge	$ 451.92	$ 486.05	7.55%
Minimum Charge - Residential	$ 34.76	$ 7.08	-79.63%
Minimum Charge - Non-Residential	$ 34.76	$ 38.52	10.82%
Facilities Charges - Distribution			
One Time	0.390%	0.274%	-29.68%
Non-One Time	1.080%	1.239%	14.75%
Facilities Charges - Transmission			
One Time	0.130%	0.130%	0.00%
Non-One Time	0.840%	0.912%	8.56%

DOMINION ENERGY NORTH CAROLINA
TOTAL ANNUALIZED REVENUE
ADJUSTMENT TO MISCELLANEOUS REVENUE
TOTAL BASIC REVENUE
DOCKET NO. E-22, SUB 694

(1) Terms and Conditions Section (Miscellaneous Charge)	(2) Current Charge	(3) Proposed Charge	(4) Difference (3) - (2)	(5) Occurrences in 2023	(6) Increase (Decrease) (4) x (5)
Section IV - Service Connections					
(Connect Charge)	$37.66	$17.32	-$20.34	17,155	-$348,938
Section X - Billing and Re-billing of Metered and Unmetered Services					
(AMI Opt-Out Monthly Fee)	$0.00	$30.88	$30.88	152	$4,694
Section XII - Payments					
(Returned Check Charge)	$13.33	$13.33	$0.00	5,318	$0
Section XIV - Customer Responsibility					
(Trouble Call Charge)	$0.00	$0.00	$0.00	0	$0
Section XVII - Reconnection of the Electric Service					
(Reconnect Charge - Normal Hours Residential)	$34.76	$7.08	-$27.68	293	-$8,110
(Reconnect Charge - After Normal Hours Residential)	$125.68	$7.08	-$118.60	20	-$2,372
(Reconnect Charge - Normal Hours Non-Residential)	$34.76	$38.52	$3.76	115	$432
(Reconnect Charge - After Normal Hours Non-Residential)	$125.68	$38.52	-$87.16	11	-$959
(Service Reconnection Charge - AMI Opt-Out)	$0.00	$34.49	$34.49	0	$0.00
Section XXI - Meter Tests Requested by Customer					
Tests - See note (a)					
(Single-phase Meter Charge)	$60.40	$55.86	-$4.54	0	$0
(Poly-phase Meter Charge)	$120.80	$111.72	-$9.08	0	$0
Section XXIII - Temporary Service					
(Overhead Charge)	$460.03	$484.69	$24.66	46	$1,134
(Underground from Transformer Charge)	$303.12	$319.51	$16.39	52	$852
(Underground from Stub-up Charge)	$451.92	$486.05	$34.13	22	$751
(Minimum Charge)	$34.76	$7.08	-$27.68	38	-$1,052
Total					-$353,568
Total Proposed Misc Service Revenue with Growth		$235,583			

DIRECT TESTIMONY
OF
JEFFREY D. MATZEN
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 694

Q. Please state your name, position of employment, and business address.

A. My name is Jeffrey D. Matzen. I am a Manager in the Strategic Planning Department for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company"). My business address is 600 E. Canal Street, Richmond, Virginia 23219.

Q. Please describe your areas of responsibility within the Company.

A. I am responsible for forecasting the Company's system energy supply mix, and total system fuel and purchased power expenses. A statement of my background and qualifications is attached as Appendix A.

Q. Have you previously testified before this Commission?

A. I have provided pre-filed testimony to the Commission in several annual fuel rider cases including in Docket No. E-22, Subs 590, 605, 654, and 675.

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

A. The purpose of my testimony is to present the Company's adjusted total system fuel expenses, which will be used by Company Witness Christoper C. Hewett to calculate the base fuel rate. I will also provide an estimate of the system fuel expense for the period July 1, 2023 – June 30, 2024, and an estimate of the deferred fuel balance as of June 30, 2024.

Q. During the course of your testimony, will you introduce an exhibit?

A. Yes. I am sponsoring Company Exhibit JDM-1, which consists of two schedules. This exhibit was prepared under my supervision and direction, and is accurate and complete to the best of my knowledge and belief.

Q. Describe the methodology that is being used to determine the adjusted total system fuel expense.

A. The system fuel expense is based on the same information that was filed by the Company in the most recent fuel factor case, Docket No. E-22, Sub 675, using fuel expenses for the historical period July 1, 2022 – June 30, 2023, and adjusted for normalization of nuclear generation and customer demand (growth and usage).

Q. What is the resulting adjusted total system fuel expense for the historical period July 1, 2022 – June 30, 2023?

A. Schedule 1 shows the adjusted system fuel expense for the historical period July 1, 2022 – June 30, 2023 of $3.24 billion, as approved by the North Carolina Utilities Commission's ("Commission") January 24, 2024, *Order Approving Fuel Charge Adjustment* issued in the Company's 2023 fuel proceeding, Docket No. E-22, Sub 675 (the "2023 Fuel Case Order"). This adjusted system fuel expense is used by Company Witness Hewett to calculate the placeholder base fuel rate included in the Application.

Q. What is the Company's forecast of the adjusted total system fuel expense for the period July 1, 2023 – June 30, 2024, based on seven months of history and five months of projected data?

A. Schedule 2 shows an estimate of the adjusted system fuel expense for the period July 1, 2023 – June 30, 2024 of $2.12 billion, which is approximately $1.1 billion less than the system fuel expense approved in the 2023 Fuel Case Order. This adjusted system fuel expense is used by Company Witness Hewett to determine the Projected Base Fuel Rate.

Q. What are the contributing factors to the lower system fuel expense in the 2023-2024 period?

A. Coal, natural gas, and power prices are lower since the previous fuel case. Table 1 below compares the forecast balance to the actual commodity prices from the 2022-2023 fuel period.

Table 1

COMMODITY	Actual JULY 22-JUNE 23	1/29/2024 JULY 23-JUNE 24	
Coal (CAPP-FOB) ($/ton)	138.21	71.46	-48%
Oil (Crude-WTI) ($/bbl)	81.05	77.97	-4%
Gas (Henry Hub) ($/mmbtu)	4.57	2.60	-43%
Gas (Zone 5) ($/mmbtu)	5.99	3.32	-45%
Gas (Z6NNY) ($/mmbtu)	4.49	2.08	-54%
Power (7 x 24 PJM West Hub) ($/MWh)	55.59	36.70	-34%
Nuclear (expense basis) ($/MWh)	6.15	5.86	-6%
* 7 months actual and 5 months forecast			

Commodity prices in the July to December 2022 period started high, including a spike for Winter Storm Elliott in December 2022. Then mild winter weather in 2023 contributed to lower natural gas, coal, and power prices. For the July 2023 to June 2024 period, the commodity prices have remained relatively low compared to the start of the previous period.

Q. What are other factors impacting the change in system fuel expense?

A. The Company continuously evaluates the customer benefits versus expenses of the units in the Company's generation fleet. As part of this effort, the Company retired Chesterfield Power Station units 5 and 6, and Yorktown Power Station unit 3, totaling approximately 1804 MW of generation capacity, in 2023, and Possum Point Station unit 5, with approximately 770 MW of capacity, in 2020. The Company does not anticipate a significant impact on the system fuel expense from these changes. The Company anticipates adding additional solar facilities totaling over 500 MW (nominal alternating current ("AC")) during the period from February 2024 to January 2025. The Company anticipates a benefit to system fuel expense from these changes and an adjustment of $28.8 million has been included on my Schedule 2 showing the calculation of the system projected fuel expense.

Q. Has the Company evaluated the current marketer percentage calculation?

A. Yes. The system fuel expense includes PJM energy market purchases, Power Purchase Agreements ("PPAs"), and off-system sales. Generally, purchases from the PJM energy market and PPA purchases do not provide fuel cost data.

The marketer percentage is a proxy used to approximate the percentage of these purchase costs related to fuel and is applied to these fuel expenses. Consistent with the Commission's conclusions in the 2023 Fuel Case Order, the Company's updated calculation of the marketer percentage based on the PJM State of the Market Reports for 2021 and 2022 will remain the same. The Company uses the same averaging method that was applied in the 2023 fuel case as well as the Company's 2019 general rate case, Docket No. E-22, Sub 562. The marketer percentage is 68% and a line item adjustment of $41.3 million was included on my Schedule 1 in the 2023 Fuel Case showing the calculation of the system projected fuel expense.

Q. What is the forecast of the Company's fuel expense recovery position for the period July 1, 2023 – June 30, 2024?

A. As of February 1, 2024, the Company's fuel recovery position since July 1, 2023 is an over-recovery of approximately $22.1 million. Since the new Rider A fuel rate went into effect on February 1, 2024, the Company's monthly fuel expenses are lower than the monthly fuel revenues. Based on projected data, the cumulative fuel over-recovery position for the 12-month test period ending June 30, 2024 is expected to be approximately $30-40 million. As explained in the Application, the Company will update the historical test period system fuel expense using actual data for purposes of submitting both its 2024 fuel factor filing in August and the Company's supplemental filing in support of the Company's Application to be filed in late summer 2024, following the submission of the 2024 fuel case.

Q. Please describe the Company's forecast of fuel expense recoveries in the second half of 2024.

A. As the current Rider A fuel rate will remain in effect through the end of 2024, the Company expects a monthly over-recovery of fuel expenses through the end of 2024, barring any major changes in unit availability or commodity prices. During the period July – December 2024, the over-recoveries could be in the range of $20 to $25 million, in addition to the expected $30 to $40 million over-recovery as of June 30, 2024.

Q. Do you have any other forms or schedules to sponsor?

A. Yes. I am sponsoring Item 46(f) of NCUC Form E-1, which is included in the Company's filing. Item 46(f) contains information about actual fuel consumption and fuel expenses for 2023, and forecasted information for 2024 and 2025.

Q. Mr. Matzen, does this conclude your direct testimony?

A. Yes.

APPENDIX A

BACKGROUND AND QUALIFICATIONS OF JEFFREY D. MATZEN

Jeffrey D. Matzen graduated from Virginia Tech in 1996 with a Bachelor of Arts degree in Economics. In 2001 he earned Master of Business Administration and Master of Public Policy degrees from the College of William and Mary. He joined the Company in 2007 as an Electric Pricing and Structuring Analyst. He has since held positions at the Company as an Energy Consulting Manager for Retail, a Business Modeling & Support Consultant for Alternative Energy Solutions, and a Market Operations Advisor for Energy Supply. In January 2020, Mr. Matzen was promoted to Manager of Generation System Planning where he is currently responsible for the Company's short-term operational forecast (PLEXOS model). Prior to joining Dominion, Mr. Matzen worked for Wells Fargo Advisors as an analyst and the Virginia Department of Taxation as an economist.

Mr. Matzen has previously submitted testimony before the Virginia and North Carolina Utilities Commissions.

DOMINION ENERGY NORTH CAROLINA
ENERGY AND FUEL EXPENSES

Normalized and Adjusted Energy and Fuel Expense based on Actual 12-Months Ended June 2023
(Company Ownership Only)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)
	12-Months Ended June 2023							June 2023				
	Expense ($)	Generation (MWh)	Rate ($/MWh)	Supply (%)	Ratio of Coal CT & CC & Other MWH To Total Sum	Coal, Oil, CT & CC, Other, Nuclear Adj. and Growth MWh	Adjusted Generation (MWh)	Expense ($)	Generation (MWh)	Rate ($/MWh)		Normalized & Adjusted Fuel Expense at Applicable Rate (8) x (11)
Coal (1)	275,837,306	6,512,101	42.36	7.1	0.1048	65,815,682	6,899,590	22,717,262	458,862	42.36	(4)	292,266,632
Nuclear												
Surry	76,889,991	13,483,876	5.70	14.7			12,671,140	6,280,917	922,551			
North Anna	76,817,661	12,783,170	6.01	13.9			13,910,410	6,501,472	1,229,589			
Total Nuclear	153,707,653 (3)	26,267,045	5.85	28.7			26,581,550	12,782,389	2,152,140	5.85	(4)	155,502,068
Heavy Oil	743,460	15,552	47.80	0.0				0	0	47.80	(4)	0
CC & CT (2)	1,592,368,933	35,360,623	45.03	38.6	0.5692	65,815,682	37,464,853	68,000,622	3,247,848	45.03	(4)	1,687,042,331
Hydro	0	3,012,451		3.3			3,012,451	0	323,810			0
Solar	0	797,131		0.9			1,638,661		79,290			
Power Transactions												
PPA Fuel	170,768,837	2,712,291	62.96	3.0			2,712,291	13,557,798	263,173	62.96	(4)	170,768,837
PPA Blend and Extend Adj												200,000
PJM Purchases	923,164,892	20,246,390	45.60	22.1	0.3259	65,815,682	21,451,239	15,009,851	1,796,597	45.60	(5)	978,101,811
Marketer Percentage Adjustment (68%)										-1.93		(41,328,246)
Net	1,093,933,729	22,958,681	47.65	25.1			24,163,530	28,567,648	2,059,770			1,107,742,403
Pumping	0	(3,271,343)		-3.6			(3,271,343)	0	(374,730)			0
Energy Supply	3,116,591,080	91,652,242	34.00	100.0			96,489,292	132,067,922	7,946,990	33.61		3,242,553,433

NOTE: ALL VALUES REFLECT COMPANY'S OWNERSHIP OF NORTH ANNA, CLOVER AND BATH COUNTY

(1) +
(2) CC & CT includes jet oil, light oil and natural gas generation
(3) Nuclear expense excludes interim storage
(4) Fuel expense rate based on weather normalized fuel expense
(5) Purchases include 71% of the fuel expense and the impact of the FTRs

DOMINION NORTH CAROLINA POWER
ENERGY AND FUEL EXPENSES

Normalized and Adjusted Energy and Fuel Expense based on Actual 12-Months Ended June 2024
(Company Ownership Only)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	12-Months Ended June 2024							June 2024 (Forecast)			
	Expense ($)	Generation (MWh)	Rate ($/MWh)	Supply (%)	Ratio of Coal CT & CC NUG & Other MWH To Total Sum	Coal, Oil, CT & CC, NUG, Other, Nuclear Adj. and Growth MWh	Adjusted Generation (MWh)	Expense ($)	Generation (MWh)	Rate ($/MWh)	Normalized & Adjusted Fuel Expense at Applicable Rate (8) x (11)
Coal (1)	293,089,620	6,586,191	44.50	6.7	0.0943	69,312,781	6,537,374	26,963,540	691,860	44.50 (4)	290,913,143
Nuclear											
Surry	78,579,292	13,109,608	5.99	13.4			13,814,210	6,618,202	1,178,180		
North Anna	77,618,070	13,560,376	5.72	13.9			13,022,660	7,355,253	981,960		
Total Nuclear	156,197,362 (3)	26,669,984	5.86	27.3			26,836,870	13,474,967	2,160,140	5.86 (4)	157,264,058
CC & CT (2)	973,738,453	40,194,905	24.23	41.2	0.5756	69,312,781	39,896,853	73,694,550	4,282,950	24.23 (4)	966,700,748
Hydro	0	2,910,170		3.0			2,910,170	0	57,480		0
Solar/ Wind	0	1,233,974		1.3			1,233,974		184,100		
Power Transactions											
NUG Fuel	140,436,859	4,263,482	32.94	4.4	0.0611	69,312,781	4,231,892	18,599,120	376,220	32.94 (4)	139,396,292
PJM Purchases	573,831,818	18,786,031	30.55	19.2	0.2690	69,312,781	18,646,732	28,056,433	951,230	30.55 (5)	569,576,838
Net	714,268,677	23,049,513	30.99	23.6			22,878,624	46,655,552	1,327,450		708,973,130
Pumping	0	(2,971,826)		-3.0			(2,971,826)	0	(249,440)		0
Energy Supply	2,137,294,113	97,672,913	21.88	100.0			96,088,066	160,788,609	8,454,540	22.10	2,123,851,079

NOTE: ALL VALUES REFLECT COMPANY'S OWNERSHIP OF NORTH ANNA, CLOVER AND BATH COUNTY

(1) Coal includes wood
(2) CC & CT includes jet oil, light oil and natural gas generation
(3) Nuclear expense excludes interim storage
(4) Fuel expense rate based on weather normalized fuel expense
(5) Purchases include 68% of the fuel expense and the impact of the FTRs

DIRECT TESTIMONY
OF
CHRISTOPHER C. HEWETT
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 694

Q. Please state your name, business address, and position of employment.

A. My name is Christopher C. Hewett, and my business address is 120 Tredegar Street, Richmond, Virginia 23219. My title is Regulatory Specialist for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company").

Q. Please describe your area of responsibility within the Company.

A. In my role I provide support and analysis for the Company's regulatory filings in Virginia and North Carolina. A statement of my background and qualifications is attached as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes. I have provided pre-filed testimony to the Commission on behalf of the Company in Docket No. E-22 Sub 604 ("2021 Demand-Side Management and Energy Efficiency"), Docket No. E-22 Sub 645 ("2022 Demand-Side Management and Energy Efficiency"), and Docket No. E-22 Sub 676 ("2023 Demand-Side Management and Energy Efficiency).

Q. Mr. Hewett, what is the purpose of your testimony in this case?

A. The purpose of my testimony is to discuss the update of the base fuel rate and provide a projection of that rate as well as a projection of the Experience Modification Factor ("EMF") anticipated in the Company's August 2024 fuel proceeding.

In addition, I discuss the Equal Percentage Methodology for allocating fuel costs to the customer classes, as agreed upon in the Stipulation entered into in the Company's 2022 fuel factor proceeding in Docket No E-22, Sub 644 ("2022 Fuel Case").

Finally, I support the Company's application for approval of a new experimental residential time-of-use ("TOU") rate schedule, designated Schedule 1E. This proposed rate schedule will be experimental, voluntary, and initially limited in the number of customers who can participate.

Q. Mr. Hewett, how is your testimony organized?

A. I have divided my testimony into the following sections:

I PLACEHOLDER BASE FUEL RATE

II. PROJECTED BASE FUEL RATE AND EMF

III. EXPERIMENTAL RESIDENTIAL TOU RATE SCHEDULE

Q. Will you introduce any exhibits as part of your testimony?

A. Yes. I am sponsoring Company Exhibit CCH-1, consisting of Schedules 1 through 4, which was prepared under my supervision and direction, and is accurate and complete to the best of my knowledge and belief. Each schedule is identified and described below:

- My Schedule 1 shows the calculation of the revised base fuel component by customer class equal to the sum of the existing class's base fuel rate and the existing fuel decrement Fuel Rider A ("Placeholder Base Fuel Rate"), to be used as the base fuel component in the rate schedules proposed to become effective for usage on and after May 1, 2024, as discussed later in my testimony.
- My Schedule 2 shows the calculation of a projected base fuel component and projected EMF Rider B for the North Carolina jurisdiction by class equal to the jurisdiction's *projected* current period fuel recovery factor ("Projected Base Fuel Rate") and *projected* EMF for the 12-month period ended June 30, 2024, using seven months of actual fuel expense data for the months of July 2023 through January 2024 and five months of forecasted fuel expense data for the months of February through June 2024.
- My Schedule 3 shows the calculation of the Equal Percentage Methodology for allocating fuel costs to the customer classes.
- My Schedule 4 shows the calculation of rates for a new experimental Residential TOU and the resulting typical residential customer bill at various usage levels.

I. PLACEHOLDER BASE FUEL RATE

Q. Why is the Company requesting an update to its base fuel rate as part of this base case?

A. While the Company's fuel factor is adjusted annually by the Commission between general rate cases, the Commission also resets the Company's base fuel factor in each base rate case, as required by subsection (f) of the North Carolina fuel factor statute, N.C. Gen. Stat. § 62-133.2. Consistent with DENC's approach to the base fuel rate approved in the 2019 Rate Case, the Company is proposing a Placeholder Base Fuel Rate to be updated through the 2024 annual fuel factor filing, as I discuss further below.

Q. Please explain the Company's plans regarding this Placeholder Base Fuel Rate.

A. Consistent with the Company's approach in the 2019 Rate Case, the Company proposes to initially set a Placeholder Base Fuel Rate for each class equal to the sum of the existing class base fuel rate plus the corresponding existing class Fuel Rider A rate, as approved by the Commission in Docket No. E-22, Sub 675 (the "2023 Fuel Case"). To support this proposal, Company Witness Jeffrey D. Matzen presents the June 30, 2023, test period adjusted system fuel expense of $3.24 billion (as provided in Schedule 1 of Company Exhibit JDM-1), which was approved by the Commission in the 2023 Fuel Case.

In my Schedule 1, Page 1 of 3, I show the calculation of the normalized North Carolina jurisdictional average fuel factor of $34.58 per MWh, as approved in the 2023 Fuel Case, for the 12-month period ending June 30, 2023. The calculation used to differentiate the approved North Carolina jurisdictional average fuel factor by class is shown in Schedule 1, Page 2 of 3. The Company proposes to set Rider A – Fuel Cost Rider to zero and use the $34.58 per MWh – differentiated by class – as the Placeholder Base Fuel Rate in each of the rate schedules effective for usage on and after May 1, 2024, as shown on my Schedule 1, Page 3 of 3. As a result of setting Rider A to zero, there will be no change in the total current period fuel factor.

The Company plans to supplement this Application – as it pertains to fuel – after the Company files its annual fuel factor application in August 2024, in order to update the Placeholder Base Fuel Rate for each class described above to incorporate the *actual* total current period factor by class proposed in the 2024 annual fuel filing ("August 2024 Base Fuel Rate").

II. PROJECTED BASE FUEL RATE AND EMF

Q. Does the Company have projections for the August 2024 Base Fuel Rate at the present time?

A. Yes. As stated in Company Witness Matzen's direct testimony in this proceeding, the Company anticipates a decrease in the base fuel factor given current projections for fuel expenses for the 12-month period ended June 30, 2024, which is the test period in the Company's annual fuel proceeding to be filed in August 2024, for fuel rates to become effective for usage on and after February 1, 2025, and due to the total delivered costs associated with certain purchases of power from qualifying facilities ("PPAs"). Company Witness

Matzen provides estimated total system fuel expenses of $2.12 billion, using seven months of actual data for the months of July 2023 through January 2024 and five months of forecasted data for the months of February through June 2024 (provided in Company Exhibit JDM-1, Schedule 2, which is attached to Company Witness Matzen's direct testimony in this proceeding).

As shown in my Schedule 2, Page 1 of 5, I calculate the projected normalized North Carolina jurisdictional average fuel factor of $22.14 per MWh (*i.e.*, the "Projected Base Fuel Rate"). The calculation used to differentiate the Projected Base Fuel Rate by voltage for each class is shown in my Schedule 2, Page 2 of 6. The calculations shown in my Schedule 2 are consistent with the methodologies used in the Company's 2023 Fuel Case, except I have updated the class expansion factors for 2023. The Projected Base Fuel Rate of $22.14 per MWh is a decrease of $12.44 per MWh from the Placeholder Base Fuel Rate of $34.58 per MWh.

Q. Does the Company have any projections for the EMF that will be filed in its annual fuel proceeding in August 2024?

A. The current period fuel over-recovery through June 30, 2024 will be the basis for the EMF to become effective on February 1, 2025. As stated in Company Witness Matzen's direct testimony in this proceeding, the Company expects the EMF balance to be in an over-recovery position of approximately $30-40 million, which will be a significant decrease from the under-recovery balance as of September 30, 2023, of $7,351,825 that is being recovered through the EMF Rider B currently in effect. Assuming an over-recovery of $30 million, this projection will result in a projected EMF credit of about $8.72 per MWh, shown in my Schedule 2 page 3, from the current EMF of $1.84 per MWh for the overall North Carolina jurisdiction. This is a reduction of $10.56 per MWh.[1] My Schedule 2 page 4 calculates projected EMF recovery rate by customer class.

Q. What is the total projected change in the fuel factor that the Company expects to be filed in the annual fuel proceeding in August 2024?

A. The Company currently projects a total decrease in the fuel factor of approximately $23.00 per MWh for the overall North Carolina jurisdiction from $42.69 per MWh to $19.69 per MWh. Refer to page 5 of my Schedule 2.

Q. Is the Company proposing any alternative methodologies related to fuel rates in this filing?

A. Yes, in accordance with the Stipulation reached in the 2022 Fuel Case, my testimony will introduce an alternative fuel recovery methodology called "The Equal Percentage Method."

Q. Please explain the Equal Percentage Method.

A. The Equal Percentage Methodology is a manner of allocating fuel expense to the customer classes based on class total revenue. It applies equally an increase or decrease in fuel billing across the classes based on the relationship

[1] For an over-recovery of $40 million on June 30, 2024, the projected EMF credit would be $11.63 per MWh. Compared to the present EMF of $1.84 per MWh, this represents a decrease of $13.47 per MWh.

between the required change in fuel recovery and the present annualized base and fuel revenue of each class. Each class receives a rate for the future period designed to recover the revenue apportioned based on the impact that the rate will have on the classes' present annualized revenue.

Q. Does the Company believe the Equal Percentage Methodology is appropriate in the current case?

A. No. The Company believes that the projected decrease in base fuel along with the prior period over-recovery in this case is too large. If there were a move to the Equal Percentage Methodology for the rate year, as shown in my Schedule 3, there would be significant shifting of the projected decrease in base fuel and the already incurred prior period fuel over-recovery from the large industrial classes to the residential, small general service, and lighting classes.

Q. You mention inter-class cost shifting. Have you quantified the approximate revenue shift among classes that would occur with the Equal Percentage Methodology?

A. As Table 1 below shows, a shift to the Equal Percentage Method at this time would result in the residential class being allocated an additional $7.6 million of the projected decrease in base fuel and prior period over-recovery balance compared to the present allocation method.

Summary of Comparison of Current Fuel Allocation to Equal % Method Allocation
Table 1

	Present Class Annualized Fuel Revenue	Current Fuel Allocation Method Proposed Fuel Revenue Minus Present Fuel Revenue	Equal % Allocation Method Allocation of Decrease in Fuel Revenue	Difference Equal % Method Minus Current Alloc Method
RESIDENTIAL	$69,918,403	($37,719,523)	($45,277,074)	($7,557,552)
SGS & PA	$32,656,921	($17,693,737)	($18,215,884)	($522,147)
LGS	$24,077,990	($12,954,813)	($10,670,153)	$2,284,660
SCHEDULE NS	$30,624,685	($16,346,822)	($11,154,653)	$5,192,168
6VP	$10,991,985	($5,936,531)	($4,458,179)	$1,478,352
OUTDOOR LIGHTING	$837,923	($456,909)	($1,304,268)	($847,359)
TRAFFIC	$22,010	($11,936)	($15,628)	($3,692)
TOTAL	$169,129,916	($91,120,270)	($91,095,840)	$24,430

Q. Could the Equal Percentage Methodology be an appropriate fuel revenue apportionment methodology?

A. Possibly. The methodology has merit and could be worth considering at a time when the change in fuel recovery is closer to zero or fuel volatility is less of an issue.

III. EXPERIMENTAL RESIDENTIAL TOU RATE SCHEDULE

Q. Before explaining the new residential TOU rate schedule that the Company is proposing, please describe the benefits of time-varying rates.

A. Time-varying rates can improve the accuracy of price signals and alignment between customer charges and usage behaviors and are better aligned with cost causation principles than standard rates. Through improved price signals, such rate structures can incent behavioral changes in customers' usage under such rates. Participating customers can reduce usage during peak periods and enable the system to avoid incurring higher variable operating expenses, such as fuel, and avoid future capacity costs. These behavioral changes can benefit participants directly through bill savings and can benefit both participants and non-participants through the reduction of system costs. While standard rate schedules may have cost recovery distinguished by season, such rates may not provide differentiation in cost recovery by season and time period.

Q. Does the Company currently have residential TOU rate schedules under which customers take service?

A. Yes, the Company currently has Schedule 1P and Schedule 1T available to residential customers. Schedule 1P is a three-part rate design with a Basic Customer Charge, seasonally-differentiated demand charges, and energy charges for the seasonally-differentiated on- and off-peak periods. Schedule 1T is a two-part rate design with a Basic Customer Charge and energy charges for the seasonally-differentiated on- and off-peak periods. Both Schedule 1P and 1T have an on-peak period in the summer season that lasts for eight hours, from 1 p.m. to 9 p.m. In the base (or non-summer) season, the on-peak period is divided into two periods, from 6:30 a.m. to 12 p.m. and 5 p.m. to 9 p.m. As described in my testimony, the proposed Schedule 1E has a different design than the current residential TOU rate schedules and, therefore, should provide new and valuable information regarding customer behavior in response to price signals. As metering technology advances, more sophisticated rate designs can improve the alignment between cost causation and price signals.

Q. Please provide a brief description of the proposed residential TOU rate.

A. Similar to the Company's residential TOU Schedule 1G approved in its Virginia Jurisdiction, the Company is proposing a residential TOU rate in North Carolina. This residential rate schedule, Schedule 1E, will be experimental, voluntary, and initially limited in the number of customers that can participate. It will include a basic customer charge, an energy charge differentiated by time periods within each season (*i.e.,* summer and non-summer), and a critical peak energy charge.

Q. For what period will Schedule 1E be available?

A. Customers may elect to participate through and including December 31, 2028, but may discontinue participation at any time. However, a customer who discontinues service under Schedule 1E may not be served under this schedule within one year of such discontinuation of service. Should the Commission approve Rate Schedule 1E, the Company respectfully requests for billing purposes, a rate effective date for usage on and after February 1, 2025.

Q. Please describe the applicability provisions of the proposed residential Schedule 1E.

A. Schedule 1E is applicable to residential customers who have AMI deployed at their premises and elect to take service under the schedule. Because Schedule 1E is an experimental rate schedule participation will be voluntary, meaning customers are not required to take service under this rate schedule. The rate schedule is limited to 500 accounts.

Q. Are there any additional applicability provisions of the proposed TOU Schedule 1E?

A. Yes. Schedule 1E would not be available to customers electing to participate (either directly or indirectly through a third-party curtailment service provider) in any PJM Interconnection, LLC Demand Response ("DR") Program or any Company-sponsored DR programs.

This limitation is needed because customers participating in DR or peak-shaving programs are already compensated for taking certain actions to limit consumption during "peak" times. If they were to also be rewarded, in a sense, for shifting this consumption to off-peak times via the rate differentials within the new proposed residential TOU schedule, these customers would be getting twice the benefits while only providing load reduction once.

Q. How does the proposed Schedule 1E compare to residential Schedule 1 when considering revenue?

A. Rate Schedule 1E has been designed to be "revenue neutral" with Rate Schedule 1 as proposed in the direct testimony of Company Witness C. Alan Givens in this proceeding to be effective May 1, 2024 (Form E-1 Item 39 Part C).

Being revenue neutral means that the proposed Schedule 1E produces the same revenue as the Company's Schedule 1 based upon all the billing determinants booked for Schedule 1 during 2023. My Schedule 4 presents the annualized base revenue for the residential rate Schedule 1 for 2023.

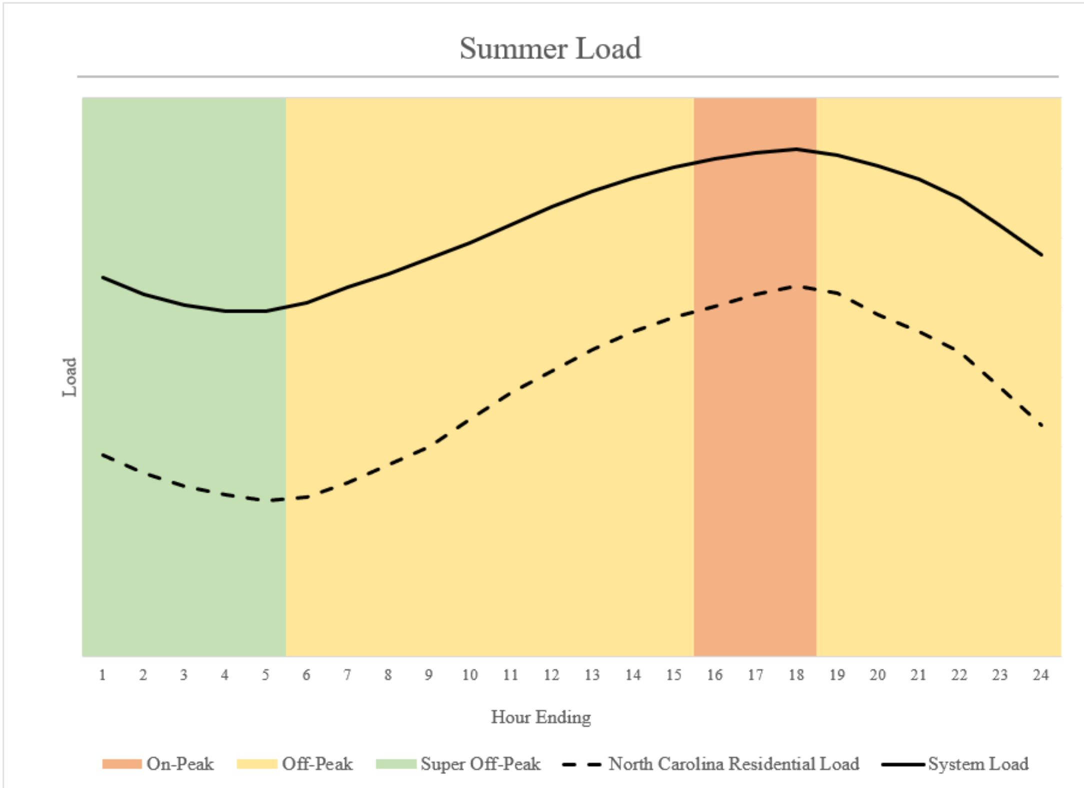
Q. Does "revenue neutral" mean that each customer's bill will be the same for Schedule 1 and proposed Schedule 1E?

A. No. Individual customer bills may not be revenue neutral between Schedule 1 and proposed Schedule 1E.

Q. Earlier you mentioned that the proposed Schedule 1E will include energy charges, differentiated by time periods within each season. Please discuss the derivation of the seasonal periods in Schedule 1E.

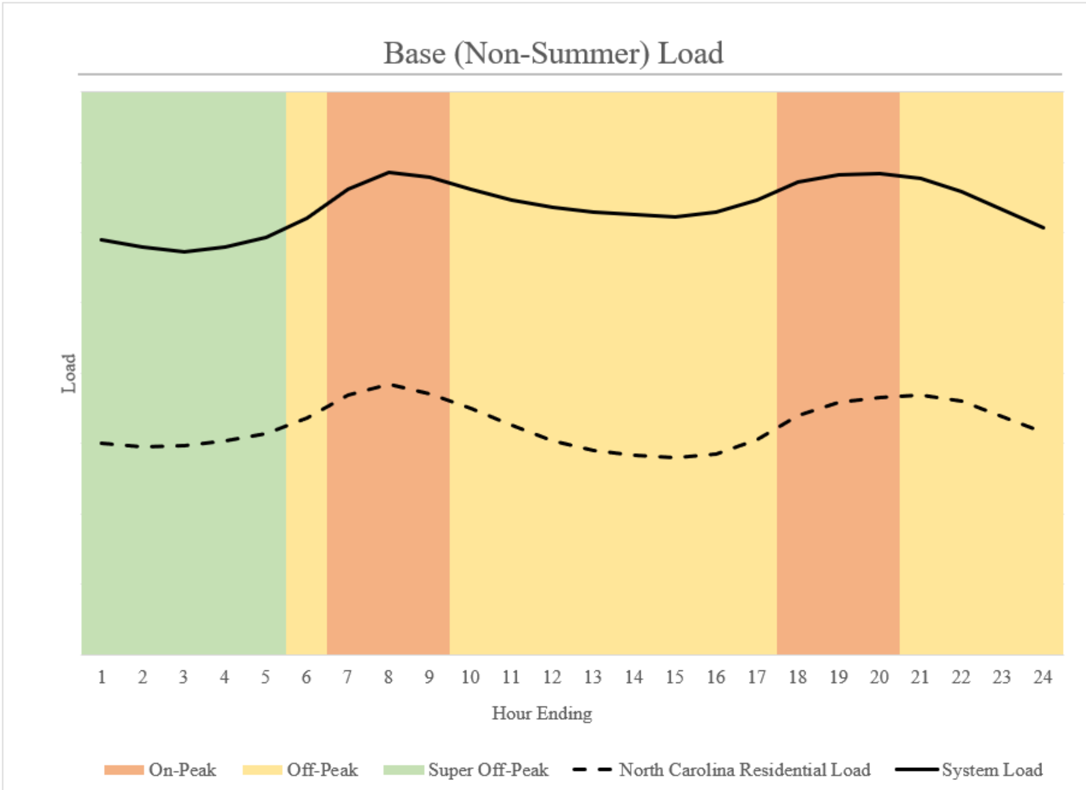
A. The residential load shapes were analyzed by month to determine the optimal seasonality of the rate schedule. The months of May through September have a typical summer load shape (with a single peak in the late afternoon or early evening) and compose the summer season. The remaining months of October through April have a non-summer load shape (both a morning and afternoon peak) and compose the Base season. Illustrative examples of the system and residential load shapes in the Summer and Base seasons are shown in Figures 1.1 and 1.2, respectively.

1 **Figure 1.1**



Summer Load
Load
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour Ending
On-Peak
Off-Peak
Super Off-Peak
North Carolina Residential Load
System Load

Figure 1.2



Q. Please discuss the derivation of the time periods proposed for Schedule 1E.

A. Schedule 1E includes the use of on-, off-, and super off-peak time periods. To determine the on-peak, off-peak, and super off-peak hours, the Company evaluated the hours during which the Company's load most frequently peaks in each season. In the Summer period, the Company's load peaks between 3 p.m. and 6 p.m. In the non-summer months, comprising the Base period, the Company's load peaks around 8 a.m. and again in the late afternoon or evening. Therefore, an on-peak period in the summer from 3 p.m. to 6 p.m. was established and two on-peak periods from 6 a.m. to 9 a.m. and 5 p.m. and

8 p.m. in the base season were established.

Consistent with the Company's residential time-of-use offering in its Virginia jurisdiction, a consistent super off-peak period was established from midnight to 5 a.m. every day, regardless of season.

All hours that were not categorized as on-peak or super off-peak were then categorized as off-peak.

Additionally, weekends and holidays (New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving (Thursday and Friday), and Christmas Eve and Christmas Day) will be excluded from having on-peak periods. Therefore, proposed Schedule 1E will have off-peak and super off-peak periods during those days.

Table 2 summarizes the seasonal and hourly rating period classifications.

Table 2

	Weekdays Excluding Holidays		**Weekends and Holidays**	
Time Period	**Summer**	**Base**	**Summer**	**Base**
24:00 - 1:00	Super Off	Super Off	Super Off	Super Off
1:00 - 2:00	Super Off	Super Off	Super Off	Super Off
2:00 - 3:00	Super Off	Super Off	Super Off	Super Off
3:00 - 4:00	Super Off	Super Off	Super Off	Super Off
4:00 - 5:00	Super Off	Super Off	Super Off	Super Off
5:00 - 6:00	Off	Off	Off	Off
6:00 - 7:00	Off	On	Off	Off
7:00 - 8:00	Off	On	Off	Off
8:00 - 9:00	Off	On	Off	Off
9:00 - 10:00	Off	Off	Off	Off
10:00 - 11:00	Off	Off	Off	Off
11:00 - 12:00	Off	Off	Off	Off
12:00 - 13:00	Off	Off	Off	Off
13:00 - 14:00	Off	Off	Off	Off
14:00 - 15:00	Off	Off	Off	Off

15:00 - 16:00	On	Off	Off	Off
16:00 - 17:00	On	Off	Off	Off
17:00 - 18:00	On	On	Off	Off
18:00 - 19:00	Off	On	Off	Off
19:00 - 20:00	Off	On	Off	Off
20:00 - 21:00	Off	Off	Off	Off
21:00 - 22:00	Off	Off	Off	Off
22:00 - 23:00	Off	Off	Off	Off
23:00 - 24:00	Off	Off	Off	Off

Q. Will there be a critical peak pricing component included in proposed Schedule 1E?

A. Yes. There may be hours during the year that are forecasted by the Company as those with peak load on the system. To encourage residential customers to reduce load on these peak hours, the Company will classify select hours as having critical peak pricing. The Company may designate up to 30 critical peak pricing days per calendar year, each lasting up to five hours in duration, where the critical peak pricing rate will apply. When this occurs, hours classified as critical peak will be priced at a critical peak pricing rate that supersedes any on-peak, off-peak, or super off-peak classification that might have occurred otherwise.

Q. Were there other guiding principles that were considered when designing this residential TOU rate?

A. Yes. A key consideration in the development of the Company's Virginia residential TOU Schedule 1G was the principle that in order to achieve behavioral response to the time-of-use pricing, the ratio of on-peak to off-peak and super off-peak charges should be 2:1. This was an objective that the rate design for the proposed Schedule 1E achieves.

Q. Please discuss the derivation of the rate components proposed for time-of-use residential rate Schedule 1E.

A. Schedule 1E utilizes a three-part rate design consisting of a customer charge, an energy charge, and a critical peak energy charge.

The Basic Customer Charge is proposed to be the same as the Residential Schedule 1 Basic Customer Charge of $14.54.

To maintain the revenue neutrality discussed earlier, annualized base revenues from Schedule 1 customers in North Carolina were used to develop target base revenues for the TOU rate. With the proposed Basic Customer Charge set at $14.54, the remaining revenue is proposed to be recovered through an energy charge that is designed with an on-peak, off-peak, and super off-peak, or a critical peak pricing component.

My Schedule 4 presents the derivation of the proposed rate components for Schedule 1E. My testimony Schedule 4 presents the proposed annualized revenue for 2023.

Q. Has the Company prepared a tariff sheet for proposed residential Schedule 1E?

A. Yes. The tariff sheet is presented in my Schedule 4.

Q. Would you explain how the proposed residential Schedule 1E would impact residential customer bills assuming no change in usage?

A. As shown in my Schedule 4, a typical Schedule 1 customer (1,000 kWh per month) with average on-peak and critical peak usage (illustrated by Customer A) would see an increase in their bill of $0.69 or 0.5% per month without changing their behavior. A typical Schedule 1 customer (1,000 kWh per month) with higher on-peak and critical peak usage (illustrated by Customer B) would see an increase in their bill of $6.55, or 4.3% per month without changing their behavior. A typical Schedule 1 customer (1,000 kWh per month) with lower on-peak and critical peak usage (illustrated by Customer C) would see a decrease in their bill of $5.76, or 3.8% per month without changing their behavior.

Q. Do you have a schedule that presents a comparison of monthly consumption at different usage levels and billing under Schedule 1 and the proposed residential Schedule 1E?

A. Yes. This comparison is presented in my Schedule 4. A calculation of the average consumption within ranges of usage has been prepared. For the average consumption within each range, a bill calculation using both Schedule 1 and proposed Schedule 1E has been calculated as well as the resulting average rate. My Schedule 4 shows the average rate for Schedule 1 and proposed Schedule 1E billing and presents a difference in these average rates and a percentage difference within each range. Approximately 90% are in the ranges between 0 kWh up to 2,500 kWh per month.

Q. If a customer changes its usage pattern based upon the price signals in proposed residential Schedule 1E, what happens to the customer's bill?

A. Assuming no change in total usage, if a residential customer shifts usage from the on-peak and critical peak periods to the off-peak period or the super off-peak period, the customer will achieve bill savings. In my Schedule 4, I show a comparison of bill impacts for shifts in usage for an average on-peak and critical peak usage residential customer (Customer A), a higher on-peak and critical peak usage customer (Customer B), and a lower on-peak and critical peak usage (Customer C). A comparison is shown against Rate Schedule 1.

Q. Mr. Hewett, does this conclude your direct testimony?

A. Yes.

APPENDIX A

BACKGROUND AND QUALIFICATIONS
OF
CHRISTOPHER C. HEWETT

Christopher C. Hewett received a Bachelor of Arts degree in Government from the College of William and Mary in 1998. Mr. Hewett joined the Company as a Senior Business Analyst in the PJM Settlement Department in 2009 and was promoted to Supervisor in 2013. In 2020 he joined the Customer Rates Department as a Regulatory Specialist. His responsibilities include providing support and analysis for the Company's regulatory filings in Virginia and North Carolina. Prior to working at the Company, he held analyst roles in both the public and private sector.

Mr. Hewett has previously filed testimony before the State Corporation Commission of Virginia, the North Carolina Utilities Commission, and the Federal Energy Regulatory Commission.

DOMINION ENERGY NORTH CAROLINA
CALCULATION OF SYSTEM AVERAGE FUEL FACTOR
TWELVE MONTHS ENDED JUNE 30, 2023
TO BE EFFECTIVE FEBRUARY 1, 2024
APPROVED IN DOCKET NO. E-22 SUB 675

EXPENSE:	12 MONTH NORMALIZED SYSTEM FUEL EXPENSE (A)	$	3,242,553,433
SALES:	12 MONTHS SYSTEM KWH SALES ADJUSTED FOR CHANGE IN USAGE, WEATHER, AND CUSTOMER GROWTH (B)		93,919,976,874
FEE:	NORTH CAROLINA REGULATORY FEE ADJUSTMENT FACTOR		1.001475

FACTOR = $\dfrac{\$3,242,553,433}{93,919,976,874} \times 1.001475$

FACTOR = $0.034576 / KWH (C) (D)

NOTES

(A) FROM DOCKET NO. E-22 SUB 675 COMPANY EXHIBIT NO. JDM-1 SCHEDULE 4

(B)	SYSTEM KWH AT SALES LEVEL [E-22 SUB 675 COMPANY EXHIBIT AJM-1, SCHEDULE 3]	89,287,302,000
	PLUS: SYSTEM KWH USAGE, WEATHER, GROWTH ADJUSTMENT [E-22 SUB 675 COMPANY EXHIBIT NO. TPS-1, REBUTTAL SCHEDULE 1, LINE 8]	4,632,674,874
	TOTAL SYSTEM SALES	93,919,976,874

(C) THE NORTH CAROLINA JURISDICTIONAL BASE FUEL FACTOR IS $0.02092/KWH APPROVED IN DOCKET NO. E-22 SUB 675

(D) WITHOUT NC REGULATORY FEE $0.034525 /KWH

Dominion Energy North Carolina
Docket No. E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
CALCULATION OF FUEL COST RIDER A
TWELVE MONTHS ENDED JUNE 30, 2023
APPROVED IN DOCKET NO. E-22 SUB 675

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
CUSTOMER CLASS	KWH SALES (A)	SYSTEM FUEL FACTOR (B)	FUEL REVENUE UNIFORM RATE (1) x (2)	CLASS EXPANSION FACTOR	CLASS KWH @ GENERATION LEVEL (1) x (4)	JURISDICTIONAL UNIFORM RATE @ GENERATION LEVEL (3a) / (5a)	JURISDICTIONAL VOLTAGE DIFFERENTIATED RATE @ SALES LEVEL (4) x (6)	VOLTAGE DIFFERENTIATED BASE FUEL RATE	FUEL COST RIDER A RATE (7) - (8)
RESIDENTIAL	1,577,823,651	$0.034576	$54,554,831	1.053586	1,662,372,909	$0.033158	$0.034935	$0.021180	$0.013755
SGS & PA	762,250,648	$0.034576	$26,355,578	1.052612	802,354,179	$0.033158	$0.034903	$0.021150	$0.013753
LGS	631,266,126	$0.034576	$21,826,658	1.045160	659,774,105	$0.033158	$0.034655	$0.020980	$0.013675
SCHEDULE NS	733,864,312	$0.034576	$25,374,092	1.012814	743,268,049	$0.033158	$0.033583	$0.020360	$0.013223
6VP	284,558,909	$0.034576	$9,838,909	1.027402	292,356,392	$0.033158	$0.034067	$0.020650	$0.013417
OUTDOOR LIGHTING	23,121,607	$0.034576	$799,453	1.053586	24,360,601	$0.033158	$0.034935	$0.021180	$0.013755
TRAFFIC	395,414	$0.034576	$13,672	1.053586	416,603	$0.033158	$0.034935	$0.021180	$0.013755
TOTAL	4,013,280,667		$138,763,192 (3a)		4,184,902,838 (5a)				

NOTES

(A)

	TEST YR KWH	CHG IN USAGE, WEATHER CUST GROWTH ADJ	TOTAL*
RESIDENTIAL	1,561,125,850	16,697,801	1,577,823,651
SGS & PA	753,395,068	8,855,580	762,250,648
LGS	631,612,093	(345,967)	631,266,126
SCHEDULE NS	693,839,558	40,024,754	733,864,312
6VP	279,573,301	4,985,608	284,558,909
OUTDOOR LIGHTING	22,315,940	805,667	23,121,607
TRAFFIC	394,190	1,224	395,414
TOTAL	3,942,256,000	71,024,667	4,013,280,667

* CLASS KWH AT SALES LEVEL PLUS CHANGE IN USAGE, WEATHER NORMALIZATION, AND CUSTOMER GROWTH [COMPANY EXHIBIT NO. TPS-1 REBUTTAL SCHEDULE 1]

(B) IN $/KWH

DOMINION ENERGY NORTH CAROLINA
CALCULATION OF PLACEHOLDER BASE FUEL RATE
TO BE EFFECTIVE ON AND AFTER FEBRUARY 1, 2024
DOCKET NO. E-22 SUB 675

	(1)	(2)	(3)
CUSTOMER CLASS	FUEL BASE VOLTAGE DIFFERENTIATED RATE @ SALES LEVEL E-22 SUB 675 (A)	FUEL COST RIDER A E-22 SUB 675 (B)	PLACE HOLDER BASE FUEL E-22 SUB 694 (1) + (2)
RESIDENTIAL	$0.021180	$0.013755	$0.034935
SGS & PA	$0.021150	$0.013753	$0.034903
LGS	$0.020980	$0.013675	$0.034655
SCHEDULE NS	$0.020360	$0.013223	$0.033583
6VP	$0.020650	$0.013417	$0.034067
OUTDOOR LIGHTING	$0.021180	$0.013755	$0.034935
TRAFFIC	$0.021180	$0.013755	$0.034935

NOTES

(A) FROM E-22 SUB 675 COMPANY EXHIBIT NO. TPS-1 REBUTTAL SCHEDULE 7, PAGE 1 OF 1, COLUMN 2

(B) FROM E-22 SUB 675 COMPANY EXHIBIT NO. TPS-1 REBUTTAL SCHEDULE 7, PAGE 1 OF 1, COLUMN 3

DOMINION ENERGY NORTH CAROLINA
CALCULATION OF PROJECTED SYSTEM AVERAGE FUEL FACTOR
TWELVE MONTHS ENDED JUNE 30, 2024
TO BE EFFECTIVE FEBRUARY 1, 2025
DOCKET NO. E-22 SUB 694

EXPENSE:	PROJECTED 12 MONTH NORMALIZED SYSTEM FUEL EXPENSE (A)	$	2,123,851,079
SALES:	12 MONTHS SYSTEM KWH SALES ADJUSTED FOR CHANGE IN USAGE, WEATHER, AND CUSTOMER GROWTH (B)		96,088,065,904
FEE:	NORTH CAROLINA REGULATORY FEE ADJUSTMENT FACTOR		1.001475

FACTOR = $\frac{\$2,123,851,079}{96,088,065,904}$ x 1.001475

FACTOR = $0.022136 / KWH (C) (D)

NOTES

(A) PROJECTED 12 MONTH NORMALIZED SYSTEM FUEL EXPENSE ESTIMATE
[E-22 SUB 694 COMPANY EXHIBIT NO. JDM-1, SCHEDULE 2

(B) PROJECTED SYSTEM KWH AT SALES LEVEL

(C) WITHOUT NC REGULATORY FEE $0.022103 / KWH

DOMINION ENERGY NORTH CAROLINA
CALCULATION OF PROJECTED BASE FUEL COMPONENT BY CLASS
TWELVE MONTHS ENDED JUNE 30, 2024
TO BE EFFECTIVE FEBRUARY 1, 2025
DOCKET NO. E-22 SUB 694

	(1)	(2)	(3)		(4)	(5)		(6)	(7)
CUSTOMER CLASS	KWH SALES E-22 SUB 694 (A)	SYSTEM FUEL FACTOR (B)	FUEL REVENUE UNIFORM RATE (1) x (2)		CLASS EXPANSION FACTOR (C)	CLASS KWH @ GENERATION LEVEL (1) x (4)		JURISDICTIONAL UNIFORM RATE @ GENERATION LEVEL (3a) / (5a)	JURISDICTIONAL VOLTAGE DIFFERENTIATED RATE @ SALES LEVEL (4) x (6)
RESIDENTIAL	1,622,763,840	$0.022136	$35,921,500		1.051219	1,705,880,181		$0.021264	$0.022353
SGS & PA	761,872,918	$0.022136	$16,864,819		1.050207	800,124,272		$0.021264	$0.022332
LGS	562,714,493	$0.022136	$12,456,248		1.045552	588,347,263		$0.021264	$0.022233
SCHEDULE NS	731,597,816	$0.022136	$16,194,649		1.010626	739,371,774		$0.021264	$0.021490
6VP	261,913,478	$0.022136	$5,797,717		1.025150	268,500,602		$0.021264	$0.021799
OUTDOOR LIGHTING	19,657,087	$0.022136	$435,129		1.051219	20,663,903		$0.021264	$0.022353
TRAFFIC	513,499	$0.022136	$11,367		1.051219	539,800		$0.021264	$0.022353
TOTAL	3,961,033,131		$87,681,429	(3a)		4,123,427,795	(5a)		

NOTES

(A) COMPANY EXHIBIT NO. CAG-1 SCHEDULE 3, PAGE 1

(B) COMPANY EXHIBIT NO. CCH-1 SCHEDULE 2, PAGE 1

(C) FOR THE 12 MONTHS ENDING DECEMBER 31, 2023

DOMINION ENERGY NORTH CAROLINA
CALCULATION OF PROJECTED EXPERIENCE MODIFICATION FACTOR - RIDER B
TWELVE MONTHS ENDED JUNE 30, 2024
TO BE EFFECTIVE FEBRUARY 1, 2025
DOCKET NO. E-22 SUB 694

EXPENSE:	PROJECTED JULY 1, 2023 - JUNE 30, 2024 NC JURISDICTIONAL FUEL EXPENSE OVER RECOVERY (A)	$	(30,000,000)
INTEREST:	18 MONTHS AT 10% ON OVER RECOVERY		($4,500,000)
NET:		$	(34,500,000)
SALES:	12 MONTHS JURISDICTIONAL KWH SALES ADJUSTED FOR CHANGE IN USAGE, WEATHER, AND CUSTOMER GROWTH (B)		3,961,033,131
FEE:	NORTH CAROLINA REGULATORY FEE ADJUSTMENT FACTOR		1.001475

$$\text{FACTOR} = \frac{(\$34{,}500{,}000)}{3{,}961{,}033{,}131} \quad x \quad 1.001475$$

FACTOR = ($0.008723) / KWH (C)

NOTES

(A) FROM COMPANY WITNESS MATZEN DIRECT TESTIMONY

(B) FROM COMPANY EXHIBIT NO. CCH-1 SCHEDULE 2, PAGE 2, COLUMN 1

(C) WITHOUT NC REGULATORY FEE ($0.008710) / KWH

DOMINION ENERGY NORTH CAROLINA
CALCULATION OF EXPERIENCE MODIFICATION FACTOR - RIDER B
TWELVE MONTHS ENDED JUNE 30, 2024
TO BE EFFECTIVE FEBRUARY 1, 2025
DOCKET NO. E-22 SUB 694

	(1)	(2)	(3)		(4)	(5)		(6)	(7)
CUSTOMER CLASS	KWH SALES (A)	NC JURISDICTIONAL EMF (B)	FUEL REVENUE UNIFORM EMF (1) x (2)		CLASS EXPANSION FACTOR	CLASS KWH @ GENERATION LEVEL (1) x (4)		UNIFORM EMF @ GENERATION LEVEL (3a) / (5a)	VOLTAGE DIFFERENTIATED EMF @ SALES LEVEL (4) x (6)
RESIDENTIAL	1,622,763,840	($0.008723)	($14,155,369)		1.051219	1,705,880,181		($0.008379)	($0.008808)
SGS & PA	761,872,918	($0.008723)	($6,645,817)		1.050207	800,124,272		($0.008379)	($0.008800)
LGS	562,714,493	($0.008723)	($4,908,559)		1.045552	588,347,263		($0.008379)	($0.008761)
SCHEDULE NS	731,597,816	($0.008723)	($6,381,728)		1.010626	739,371,774		($0.008379)	($0.008468)
6VP	261,913,478	($0.008723)	($2,284,671)		1.025150	268,500,602		($0.008379)	($0.008590)
OUTDOOR LIGHTING	19,657,087	($0.008723)	($171,469)		1.051219	20,663,903		($0.008379)	($0.008808)
TRAFFIC	513,499	($0.008723)	($4,479)		1.051219	539,800		($0.008379)	($0.008808)
TOTAL	3,961,033,131		($34,552,092)	(3a)		4,123,427,795	(5a)		

NOTES

(A) COMPANY EXHIBIT NO. CCH-1 SCHEDULE 1, PAGE 2

(B) COMPANY EXHIBIT NO. CCH-1 SCHEDULE 2, PAGE 3

DOMINION ENERGY NORTH CAROLINA
TOTAL FUEL COST LEVEL - PRESENT AND PROPOSED
TO BE EFFECTIVE FEBRUARY 1, 2025

	(1)	(2)	(3)	(4)	(5)
NC JURISDICTION	BASE FUEL COMPONENT $/KWH	RIDER A FUEL CHARGE $/KWH	RIDER B EMF $/KWH	RIDER B1 EMF $/KWH	TOTAL FUEL RATE $/KWH
PRESENT	$0.020920	$0.013656	$0.001835	$0.006280	$0.042691
PROPOSED	$0.022136	$0.000000	($0.008723)	$0.006280	$0.019693
CHANGE	$0.001216	($0.013656)	($0.010558)	$0.000000	($0.022998)
RESIDENTIAL	BASE FUEL COMPONENT $/KWH	RIDER A FUEL CHARGE $/KWH	RIDER B EMF $/KWH	RIDER B1 EMF $/KWH	TOTAL FUEL RATE $/KWH
PRESENT	$0.021180	$0.013755	$0.001854	$0.006297	$0.043086
PROPOSED	$0.022353	$0.000000	($0.008808)	$0.006297	$0.019842
CHANGE	$0.001173	($0.013755)	($0.010662)	$0.000000	($0.023244)
SGS & PA	BASE FUEL COMPONENT $/KWH	RIDER A FUEL CHARGE $/KWH	RIDER B EMF $/KWH	RIDER B1 EMF $/KWH	TOTAL FUEL RATE $/KWH
PRESENT	$0.021150	$0.013753	$0.001853	$0.006108	$0.042864
PROPOSED	$0.022332	$0.000000	($0.008800)	$0.006108	$0.019640
CHANGE	$0.001182	($0.013753)	($0.010653)	$0.000000	($0.023224)
LGS	BASE FUEL COMPONENT $/KWH	RIDER A FUEL CHARGE $/KWH	RIDER B EMF $/KWH	RIDER B1 EMF $/KWH	TOTAL FUEL RATE $/KWH
PRESENT	$0.020980	$0.013675	$0.001839	$0.006295	$0.042789
PROPOSED	$0.022233	$0.000000	($0.008761)	$0.006295	$0.019767
CHANGE	$0.001253	($0.013675)	($0.010600)	$0.000000	($0.023022)

NOTES

( ) DENOTES NEGATIVE VALUE

Dominion Energy North Carolina
Docket No. E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA POWER
TOTAL FUEL COST LEVEL - PRESENT AND PROPOSED
TO BE EFFECTIVE FEBRUARY 1, 2025

	(1)	(2)	(3)	(4)	(5)
SCHEDULE NS	BASE FUEL COMPONENT $/KWH	RIDER A FUEL CHARGE $/KWH	RIDER B EMF $/KWH	RIDER B1 EMF $/KWH	TOTAL FUEL RATE $/KWH
PRESENT	$0.020360	$0.013223	$0.001783	$0.006494	$0.041860
PROPOSED	$0.021490	$0.000000	($0.008468)	$0.006494	$0.019516
CHANGE	$0.001130	($0.013223)	($0.010251)	$0.000000	($0.022344)
6VP	BASE FUEL COMPONENT $/KWH	RIDER A FUEL CHARGE $/KWH	RIDER B EMF $/KWH	RIDER B1 EMF $/KWH	TOTAL FUEL RATE $/KWH
PRESENT	$0.020650	$0.013417	$0.001808	$0.006093	$0.041968
PROPOSED	$0.021799	$0.000000	($0.008590)	$0.006093	$0.019302
CHANGE	$0.001149	($0.013417)	($0.010398)	$0.000000	($0.022666)
OUTDOOR LIGHTING	BASE FUEL COMPONENT $/KWH	RIDER A FUEL CHARGE $/KWH	RIDER B EMF $/KWH	RIDER B1 EMF $/KWH	TOTAL FUEL RATE $/KWH
PRESENT	$0.021180	$0.013755	$0.001854	$0.005838	$0.042627
PROPOSED	$0.022353	$0.000000	($0.008808)	$0.005838	$0.019383
CHANGE	$0.001173	($0.013755)	($0.010662)	$0.000000	($0.023244)
TRAFFIC	BASE FUEL COMPONENT $/KWH	RIDER A FUEL CHARGE $/KWH	RIDER B EMF $/KWH	RIDER B1 EMF $/KWH	TOTAL FUEL RATE $/KWH
PRESENT	$0.021180	$0.013755	$0.001854	$0.006074	$0.042863
PROPOSED	$0.022353	$0.000000	($0.008808)	$0.006074	$0.019619
CHANGE	$0.001173	($0.013755)	($0.010662)	$0.000000	($0.023244)

NOTES

( ) DENOTES NEGATIVE VALUE

Dominion Energy North Carolina
Docket No. E-22, Sub 694

DOMINION ENERGY NORTH CAROLINA
CALCULATION OF EQUAL PERCENTAGE METHODOLOGY
DOCKET NO. E-22 SUB 694

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
CUSTOMER CLASS	KWH SALES	PRESENT CLASS FUEL RATE	PRESENT CLASS ANNUALIZED FUEL REVENUE	PROPOSED CLASS FUEL RATE	PROPOSED CLASS ANNUALIZED FUEL REVENUE	PROPOSED CHANGE IN FUEL REVENUE	UNIFORM CHANGE IN FUEL RATE	UNIFORM DECREASE IN FUEL REVENUE	REVENUE FROM 2024 RATE CASE E-22 SUB 694	EQUAL % ALLOCATION METHOD FUEL DECREASE	DIFFERENCE BTWN EQUAL % METHOD MINUS CURRENT ALLOCATION METHOD
	(A)	(B)	(1) x (2)	(C)	(1) x (4)	(5) - (3)	(D)	(1) x (7)	(E)	(9) x (9a)	(10) - (6)
RESIDENTIAL	1,622,763,840	$0.043086	$69,918,403	$0.019842	$32,198,880	($37,719,523)	($0.022998)	($37,320,323)	$214,059,091	($45,277,074)	($7,557,552)
SGS & PA	761,872,918	$0.042864	$32,656,921	$0.019640	$14,963,184	($17,693,737)	($0.022998)	($17,521,553)	$86,120,307	($18,215,884)	($522,147)
LGS	562,714,493	$0.042789	$24,077,990	$0.019767	$11,123,177	($12,954,813)	($0.022998)	($12,941,308)	$50,445,913	($10,670,153)	$2,284,660
SCHEDULE NS	731,597,816	$0.041860	$30,624,685	$0.019516	$14,277,863	($16,346,822)	($0.022998)	($16,825,287)	$52,736,511	($11,154,653)	$5,192,168
6VP	261,913,478	$0.041968	$10,991,985	$0.019302	$5,055,454	($5,936,531)	($0.022998)	($6,023,486)	$21,077,194	($4,458,179)	$1,478,352
OUTDOOR LIGHTING	19,657,087	$0.042627	$837,923	$0.019383	$381,013	($456,909)	($0.022998)	($452,074)	$6,166,266	($1,304,268)	($847,359)
TRAFFIC	513,499	$0.042863	$22,010	$0.019619	$10,074	($11,936)	($0.022998)	($11,809)	$73,886	($15,628)	($3,692)
TOTAL	3,961,033,131		$169,129,916		$78,009,646	($91,120,270)		($91,095,840)	$430,679,167	($91,095,840)	$24,430 (F)
									-21.2%	(9a) = (8) / (9)	

NOTES

(A) COMPANY EXHIBIT NO. CCH-1 SCHEDULE 2, PAGE 2
(B) COMPANY EXHIBIT NO. CCH-1 SCHEDULE 2, PAGE 5
(C) COMPANY EXHIBIT NO. CCH-1 SCHEDULE 2, PAGE 5
(D) COMPANY EXHIBIT NO. CCH-1 SCHEDULE 2, PAGE 5
(E) COMPANY EXHIBIT NO. CAG-1 SCHEDULE 2
(F) DIFFERENCE DUE TO UNIFORM VERSUS CLASS-DIFFERENTIATED FUEL RATES.

DOMINION ENERGY NORTH CAROLINA
TIME-OF-USE RATE DESIGN
ANNUALIZED BASE REVENUES
SCHEDULE 1 - RESIDENTIAL

	PROPOSED RATES IN EFFECT 2/1/2025		
	BILLING UNITS 12/31/2023	PROPOSED BASIC RATE	PROPOSED BASIC REVENUE
BASIC CUSTOMER CHARGE	1,289,832	$14.54	$18,754,157
PEAK MONTHS - ALL KWH *	567,765,166	$0.104239	$59,183,279
BASE MONTHS - ALL KWH *	883,255,779	$0.086873	$76,731,089
CONSERVATION DISCOUNT - 5%			
PEAK MONTHS - ALL KWH *	22,367,869	$0.099027	$2,215,024
BASE MONTHS - ALL KWH *	30,797,465	$0.082529	$2,541,695
TOTAL	1,504,186,279		$159,425,245

* Excludes all fuel

DOMINION ENERGY NORTH CAROLINA
TIME-OF-USE RATE DESIGN
DERIVATION OF PROPOSED RATES
PROPOSED TIME-OF-USE RATE SCHEDULE 1E

	HOURS	PERCENTAGE OF COSTS	TARGET REVENUE	DESIGN UNITS	ALL-IN PRICE PER KWH	PROPOSED PRICE PER KWH*
ON-PEAK - SUMMER	250	7.1%	$14,677,267	55,969,385	$0.262237	$0.219151
OFF-PEAK - SUMMER	2512	25.2%	$51,797,404	480,111,483	$0.107886	$0.064800
SUPER OFF-PEAK - SUMMER	765	4.2%	$8,705,275	94,397,482	$0.092219	$0.049133
ON-PEAK - BASE	876	13.5%	$27,761,981	157,523,220	$0.176241	$0.133155
OFF-PEAK - BASE	3148	25.3%	$52,061,621	505,665,795	$0.102957	$0.059871
SUPER OFF-PEAK - BASE	1059	7.9%	$16,218,687	158,354,928	$0.102420	$0.059334
CRITICAL PEAK PRICING	150	16.7%	$34,258,223	52,163,986	$0.656741	$0.613655
TOTAL		**100.00%**	**$205,480,458**			

* Excludes all fuel

FUEL CHARGES IN EFFECT AS OF FEBRUARY 1, 2024	
PLACEHOLDER BASE FUEL	$0.034935
RIDER A	$0.000000
RIDER B	$0.001854
RIDER B1	$0.006297

SUM OF FUEL CHARGES	$0.043086
RESIDENTIAL SCH 1 KWH	1,504,186,279
RESIDENTIAL SCH 1 FUEL REVENUE	$ 64,809,370
RESIDENTIAL SCH 1 REVENUE MINUS BCC FROM TESTIMONY PAGE 1	$ 140,671,088
RESIDENTIAL SCH 1 TOTAL REVENUE	$ 205,480,458

DOMINION ENERGY NORTH CAROLINA
TIME-OF-USE RATE DESIGN
ANNUALIZED BASE REVENUES
PROPOSED TIME-OF-USE RATE SCHEDULE 1E

		PROPOSED	
	DESIGN UNITS	**BASIC RATE**	**BASIC REVENUE**
BASIC CUSTOMER CHARGE	1,289,832	$14.54	$18,754,157
ENERGY-KWH			
ON-PEAK - SUMMER	55,969,385	$0.219151	$12,265,770
OFF-PEAK - SUMMER	480,111,483	$0.068966	$33,111,321
SUPER OFF-PEAK - SUMMER	94,397,482	$0.038540	$3,638,065
ON-PEAK - BASE	157,523,220	$0.164896	$25,974,935
OFF-PEAK - BASE	505,665,795	$0.068770	$34,774,504
SUPER OFF-PEAK - BASE	158,354,928	$0.049861	$7,895,807
CRITICAL PEAK PRICING	52,163,986	$0.441122	$23,010,686
TOTAL	**1,504,186,279**		**$159,425,245**

DOMINION ENERGY NORTH CAROLINA
TIME-OF-USE RATE DESIGN
TYPICAL BILL IMPACT ASSUMING NO CHANGE IN USAGE
PROPOSED TIME-OF-USE RATE SCHEDULE 1E

CUSTOMER A, B, C - SCHEDULE 1

	KWH
SUMMER	1,000
BASE	1,000

CUSTOMER A - SCHEDULE 1E

	CRITICAL PEAK PRICING KWH	ON-PEAK KWH	OFF-PEAK KWH	SUPER OFF-PEAK KWH
SUMMER	75	80	705	140
BASE	5	190	615	190

CUSTOMER B - SCHEDULE 1E

	CRITICAL PEAK PRICING KWH	ON-PEAK KWH	OFF-PEAK KWH	SUPER OFF-PEAK KWH
SUMMER	85	105	690	120
BASE	10	215	585	190

CUSTOMER C - SCHEDULE 1E

	CRITICAL PEAK PRICING KWH	ON-PEAK KWH	OFF-PEAK KWH	SUPER OFF-PEAK KWH
SUMMER	55	65	720	160
BASE	2	163	645	190

	SCHEDULE 1	CUSTOMER A PROPOSED SCH. 1E	CUSTOMER B PROPOSED SCH. 1E	CUSTOMER C PROPOSED SCH. 1E
REVENUES - SUMMER				
BASIC CUSTOMER CHARGE	$14.54	$14.54	$14.54	$14.54
ALL KWH	$104.24	$104.63	$112.72	$94.33
FUEL PLUS ALL RIDERS	$44.97	$44.97	$44.97	$44.97
TOTAL BILL - SUMMER	$163.75	$164.14	$172.23	$153.84
REVENUES - BASE				
BASIC CUSTOMER CHARGE	$14.54	$14.54	$14.54	$14.54
ALL KWH	$86.87	$85.30	$89.56	$81.59
FUEL PLUS ALL RIDERS	$44.97	$44.97	$44.97	$44.97
TOTAL BILL - BASE	$146.38	$144.81	$149.07	$141.10
WEIGHTED ANNUAL BILL	$1,826.08	$1,834.41	$1,904.68	$1,756.94
WEIGHTED MONTHLY BILL	$152.17	$152.87	$158.72	$146.41
CHANGE IN MONTHLY BILL		$0.69	$6.55	-$5.76
% CHANGE IN MONTHLY BILL		0.5%	4.3%	-3.8%

DOMINION ENERGY NORTH CAROLINA
TIME-OF-USE RATE DESIGN
TYPICAL BILL IMPACT AT SEVERAL LEVELS OF CONSUMPTION
PROPOSED TIME-OF-USE RATE SCHEDULE 1E

RANGE OF MONTHLY USAGE	AVERAGE RATE SCH 1	AVERAGE RATE SCH 1E	DIFFERENCE	% DIFFERENCE
0-500 kWh	$0.196867	$0.197477	$0.000610	0.3%
500-1000 kWh	$0.157197	$0.157306	$0.000109	0.1%
1000-1500 kWh	$0.149330	$0.149491	$0.000161	0.1%
1500-2000 kWh	$0.145825	$0.145932	$0.000106	0.1%
2000-2500 kWh	$0.143864	$0.143979	$0.000116	0.1%
2500-3000 kWh	$0.142615	$0.142805	$0.000190	0.1%
3000-3500 kWh	$0.141753	$0.141904	$0.000150	0.1%
3500-4000 kWh	$0.141120	$0.141240	$0.000121	0.1%
4000-4500 kWh	$0.140638	$0.140770	$0.000133	0.1%
4500-5000 kWh	$0.140257	$0.140374	$0.000117	0.1%
5000-6000 kWh	$0.139847	$0.139981	$0.000133	0.1%
6000-7000 kWh	$0.139415	$0.139578	$0.000163	0.1%
7000-8000 kWh	$0.139094	$0.139235	$0.000140	0.1%
8000-9000 kWh	$0.138857	$0.138979	$0.000122	0.1%
9000-10000 kWh	$0.138665	$0.138809	$0.000144	0.1%
>10000 kWh	$0.138149	$0.138282	$0.000133	0.1%

DOMINION ENERGY NORTH CAROLINA
TIME-OF-USE RATE DESIGN
TYPICAL BILL IMPACT ASSUMING CHANGE IN USAGE PATTERN
PROPOSED TIME-OF-USE RATE SCHEDULE 1E

CHANGE IN CUSTOMER BILLS COMPARED TO SCHEDULE 1

	PERCENTAGE SHIFT IN USAGE FROM ON-PEAK AND CRITICAL PEAK TO OFF-PEAK					
	0% SHIFT	6% SHIFT	10% SHIFT	15% SHIFT	20% SHIFT	30% SHIFT
CUSTOMER A	$0.69	-$0.07	-$0.67	-$1.39	-$1.95	-$3.55
CUSTOMER B	$6.55	$5.55	$5.00	$4.00	$3.29	$1.52
CUSTOMER C	-$5.76	-$6.48	-$6.86	-$7.37	-$7.81	-$8.98

CHANGE IN CUSTOMER BILLS COMPARED TO SCHEDULE 1E WITH 0% SHIFT IN USAGE

	PERCENTAGE SHIFT IN USAGE FROM ON-PEAK AND CRITICAL PEAK TO OFF-PEAK				
	6% SHIFT	10% SHIFT	15% SHIFT	20% SHIFT	30% SHIFT
CUSTOMER A	-$0.77	-$1.37	-$2.08	-$2.64	-$4.24
CUSTOMER B	-$1.00	-$1.55	-$2.55	-$3.26	-$5.03
CUSTOMER C	-$0.72	-$1.10	-$1.61	-$2.05	-$3.21

Schedule 1E
RESIDENTIAL SERVICE
(EXPERIMENTAL)

I. APPLICABILITY

This schedule is applicable to the separately metered and billed supply of alternating current electricity for use in and about (a) a single-family residence, flat or apartment, (b) a combination farm and one occupied single-family residence, flat or apartment, (c) a private residence used as a boarding and/or rooming house with no more than one cooking installation nor more than ten bedrooms or (d) "family care home" as defined in Chapter 168, Section 21(1) of the General Statutes of North Carolina.

This schedule is not applicable to (i) individual motors rated over 15 HP, (ii) commercial use, or (iii) separately metered service to accessory buildings or equipment on residential property that are not themselves intended or suitable for residence. This schedule is also not applicable for breakdown, relay, or parallel operation service.

II. AVAILABILITY

Subject to a participation limitation of 500 accounts, this schedule is available only where:

A. The Company has installed and deployed its advanced metering infrastructure (AMI);

B. The Customer does not participate in a PJM Interconnection, LLC or Company-Sponsored demand response program or peak-shaving demand response program; and

C. The Company received the Customer's voluntary request for service in accordance with this schedule through and including December 31, 2028. A Customer who discontinues service under this schedule after less than one year of service may not be served under this schedule for the Customer's account at the same premise within one year of such discontinuation of service.

III. MONTHLY RATE

A. Basic Customer Charge
Basic Customer Charge $14.54 per billing month

B. Plus Energy Charge

1. For the period beginning May 1 and extending through September 30

All on-peak kWh	*@*	*25.4086¢ per kWh*
All off-peak kWh	*@*	*10.3901¢ per kWh*
All super off-peak kWh	*@*	*7.3475¢ per kWh*

(Continued)

Schedule 1E
RESIDENTIAL SERVICE
(EXPERIMENTAL)

(Continued)

III. MONTHLY RATE (Continued)

2. For period beginning October 1 and extending through April 30

All on-peak kWh	*@*	*19.9831¢ per kWh*
All off-peak kWh	*@*	*10.3705¢ per kWh*
All super off-peak kWh	*@*	*8.4796¢ per kWh*

3. Critical Peak Pricing

All kWh	*@*	*47.6057¢ per kWh*

The energy charges in this schedule contain a base fuel cost of 3.4935 cents per kilowatt-hour.

C. The energy charges in III.B., above, shall be increased or decreased by any applicable Riders.

D. The minimum charge shall be the Basic Customer Charge in III.A., above.

IV. LATE PAYMENT CHARGE

Current bills are due and payable from the billing date. When bills are not paid in full within twenty-five (25) days from the billing date, a late payment charge of 1% per month, based on the unpaid balance, will be added to the current bill.

V. DETERMINATION OF ON-PEAK, OFF-PEAK, SUPER OFF-PEAK, AND CRITICAL PEAK PRICING HOURS

A. On-peak hours (Except Certain Holidays and Exemptions Defined in Paragraph VI.)

1. For the period of May 1 through September 30:
3 P.M. to 6 P.M., Monday through Friday

2. For the period of October 1 through April 30:
6 A.M. to 9 A.M. and 5 P.M. to 8 P.M., Monday through Friday

B. Off-peak hours (Except Exemptions Defined in Paragraph VI.)

1. For the period of May 1 through September 30:
5 A.M. to 3 P.M. and 6 P.M. to 12 A.M., Monday through Friday

2. For the period of October 1 through April 30:
5 A.M. to 6 A.M., 9 A.M. to 5 P.M., and 8 P.M. to 12 A.M., Monday through Friday

3. For weekends and holidays, as identified in Paragraph V.E. below:
5 A.M. to 12 A.M.

(Continued)

Schedule 1E
RESIDENTIAL SERVICE
(EXPERIMENTAL)

(Continued)

V. DETERMINATION OF ON-PEAK, OFF-PEAK, SUPER OFF-PEAK, AND CRITICAL PEAK PRICING HOURS (Continued)

C. Super off-peak hours are 12 A.M. to 5 A.M., except for exemptions defined in Paragraph VI., below.

D. Critical Peak Pricing, as defined in Paragraph VI., below.

E. Holidays:

The following holidays are observed: New Year's Day, Good Friday, Memorial Day (observed), July 4, Labor Day, Thanksgiving, (Thursday and Friday), Christmas Eve and Christmas Day.

VI. APPLICATION AND NOTIFICATION OF CRITICAL PEAK PRICING

The Company may call up to 30 Critical Peak Pricing days, lasting up to five hours in duration, per calendar year. Any five hour block designated by the Company as Critical Peak Pricing will be priced at the Critical Peak Pricing rate in Paragraph III.B.3. A Critical Peak Pricing block will supersede the on-peak, off-peak, and super off-peak energy charge defined in Paragraphs III.B.1. and III.B.2., as well as the corresponding hours, including holidays, as defined in Paragraph V.

The classification of Critical Peak Pricing days and their applicable Critical Peak block hours for each day will be determined by the Company and will be available via the Internet (at a site to be designated by the Company) by 6 p.m. the preceding day. Receipt of Critical Peak Pricing notification is the Customer's responsibility.

VII. METER READING AND BILLING

Meters may be read in units of 10 kilowatt-hours and bills rendered accordingly.

VIII. TERM OF CONTRACT

Open order.

DIRECT TESTIMONY
OF
JERRI A. BROOKS
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 694

Q. Please state your name, business address, and position of employment.

A. My name is Jerri A. Brooks, and my business address is 8266 Meetze Rd Warrenton, VA 20187. I am a Customer Contracts Specialist for Virginia Electric and Power Company, which does business in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company").

Q. Please describe your areas of responsibility within the Company.

A. I am responsible for supporting Electric Distribution Design activities as provided for in the Company's Terms and Conditions for the Provision of Electric Service ("Terms and Conditions") on file with the North Carolina Utilities Commission (the "Commission") as well as the associated policies that support those Terms and Conditions. A statement of my background and qualifications is attached as Appendix A.

Q. Have you previously testified before this Commission?

A. No.

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

A. I am testifying in support of proposed revisions to Section XXII of the Terms and Conditions, Electric Line Extensions and Installations, which is also referred to as the "line extension plan" or the "LEP."

Q. Will you be introducing any exhibits with your testimony?

A. No. I am, however, supporting Section XXII of the Terms and Conditions as presented in Company Witness C. Alan Givens exhibit CAG-1.

Q. Please provide an overview of LEPs.

A. Generally, utility LEPs provide the rights, responsibilities, and conditions for a utility and its customers when a customer requests an extension of an electric utility's distribution lines. For example, when a customer requests new service or a change in existing service for an individual residence, housing development, or non-residential service, the LEP establishes the charging methodology and general guidelines that must be met for the line extension to be installed.

Q. Please provide background on the Company's LEP.

A. The most recent, significant revisions to the Company's LEP were approved in the Company's 1993 rate case proceeding in Docket No. E-22, Sub 333. In that proceeding, the Company requested, and the Commission approved, a change related to payment for line extensions. Specifically, the revisions required up-front payments for new residential services subject to a cost versus anticipated revenue calculation ("revenue test") to recover a portion of new distribution investments. This change also limited the amount of capital investment added to the rate and prevented existing customers from overly subsidizing line extensions for new customers.

The Company also proposed, and the Commission approved, minor changes to the LEP in the Company's 2005 rate case proceeding in Docket No. E-22, Sub 412 to further define line extension charges within subdivisions with lot sizes greater than 30,000 square feet. There have been no additional changes since that time.

Q. What changes are the Company proposing to its LEP?

A. The Company is proposing updates and changes to several provisions of the LEP. First, the Company has proposed modifications to the definition of an "Approach Line" in Section XXII.B. to simplify it as the primary voltage facilities extending from an existing source to the property of the customer or developer requesting service. In the current LEP, an Approach Line will be installed by the least-cost method. In the modified, proposed LEP, an Approach Line will be installed overhead. If a customer chooses or is required to install the Approach Line underground, payment of the cost difference will be required. In nearly all instances, a primary Approach Line installed overhead is the least cost method, and it is less expensive to tap overhead primary approach lines to serve additional customers.

Q. What other changes is the Company proposing to the LEP?

A. The Company is also proposing a change to simplify the residential revenue credits. Residential revenue credits are based on a customer's anticipated electrical usage and calculating the annual revenue, less fuel revenue, based on the applicable rate schedule. The revenue credit is then compared against the estimated charge to provide service to determine if a customer must contribute to the construction charges incurred by the Company.

The Company is proposing to eliminate Table 1, in the currently effective LEP, which includes variable revenue credit allowances based on the type of premise (single-family, condo, townhome, etc.) and number and type of appliances in favor of a simplified revenue credit allowance of 17,307 kilowatt-hours ("kWh") based on the current average kilowatt-hour sales of a single-family home. This proposed revenue credit is higher than the overall average kilowatt-hour sales of 15,051 kWh from the Company's 2021 annual load study for all residential customers. The 17,307 kWh allowance also strikes a balance between the sum of the currently effective Table 1 total kWh allowances possible for a single-family all-electric home and the 15,051 kWh average residential annual sales.

In addition, the current LEP allows for a residential revenue credit allowance of 1 year, 2 years, 6 years, or 7 years depending on the type of construction (primary approach line, local distribution line, secondary service) and customer type (individual residence or residential development). The Company is proposing to change the current LEP's variable revenue credit allowance to a seven-year revenue credit for each new residential service. This change will simplify the application of revenue credits and provide the added benefit of a greater revenue credit allowance to those residential customers who would have only received one year, two years, or six years of revenue credit under the current LEP.

Customers not served under paragraph C of the currently effective LEP, referred to as non-residential or three-phase residential customers in the proposed modifications to the LEP, will continue to have the same two-year revenue credit allowance. Primary Approach Lines will continue to be installed overhead, similar to the current LEP, with the customer being responsible for paying the cost difference if they request or require underground primary approach lines. For the line extension inside their property or development, the customer can choose overhead or underground facilities, but will also be subject to the cost difference if the requested underground facilities cannot be installed with standard trenching.

Q. Are there any other proposed changes to the LEP you would like to highlight?

A. Yes. The Company is also proposing to remove the revenue test currently required when a customer requests to upgrade inadequate service. Facilities are considered inadequate when their capacity is not sufficient to serve the load at the existing service characteristics. Under the current LEP, if a residential customer requests to upgrade inadequate service, the customer receives an incremental revenue credit based on any additional proposed load and then is charged the remainder as a Contribution in Aid of Construction ("CIAC"). The proposed changes to the LEP would replace inadequate residential overhead service with adequate overhead service at no charge and inadequate residential underground service with adequate underground service at no charge provided that standard trenching can be utilized.

If a customer requests to upgrade adequate service, then they will be responsible for the cost of the upgrade. Similar to the current line extension plan, if a residential customer wishes to convert existing inadequate overhead service to underground, a credit will be given for the Company's cost to upgrade the service overhead against the cost of installing the underground service. A definition of "Adequacy" has been added to Section XXII.B. of the LEP to support these changes.

Q. Why is the Company now seeking modifications to its LEP?

A. The Company last made major amendments to its LEP approximately 30 years ago. The proposed modifications to its existing LEP simplify and update the LEP based on the Company's experience since the last major amendment. For example, the current Section XXII includes a residential revenue credit Annual kWh Consumption Allowance Table 1 that has not been updated since the revisions in 1993. The existing LEP also contains various years of residential revenue credit allowed based on the type and location of facilities to be constructed to provide new service and residential development charges based on differing lot size parameters. The proposed changes to Section XXII combine, update, and simplify these aforementioned variables in a way that still provides equity of cost recovery, while enabling our customers to be better able to understand the method of determining any CIAC that may be required to provide new service. Similarly, the proposed modifications to the residential revenue credit and method of accounting for service upgrades allows for a simplified, modernized LEP that results in a financial benefit for the majority of the Company's customers while maintaining cost neutrality for the Company.

Q. Has the Company experienced many issues with its North Carolina customers relevant to the LEP?

A. Issues with North Carolina customers relevant to the line extension plan are commonly related to misunderstandings regarding the calculated CIAC for new residential development projects. The various applications of revenue credits depending on the method of construction of the project, notably the approach line versus the local distribution line receiving different applications of revenue credit, have caused customer confusion related to the resulting CIAC when, in fact, the projects were calculated correctly. The charge per lot and lot size criteria when combined with the overall revenue credit allowances for the CIAC calculation has also been a source of confusion for customers; and the application thereof has been cumbersome and problematic.

Q. Do you believe the proposed modifications to the LEP will help to mitigate these issues?

A. Yes. The proposed modifications to the LEP will help mitigate these issues by removing the lot size and cost per lot language of Section XXII.C.1.a-e., removing the Table 1 in favor of a simple revenue credit allowance based on current average kilowatt-hour residential sales, and streamlining the revenue credit application into a 7-year allowance for each residence. With the proposed changes a customer would be able to review Section XXII and more easily interpret and understand any applicable CIAC calculated for their project.

Q. Does this conclude your direct testimony?

A. Yes.

APPENDIX A

BACKGROUND AND QUALIFICATIONS OF JERRI BROOKS

Ms. Brooks received a Bachelor of Science degree in Animal and Veterinary Science from West Virginia University in 1999.

Ms. Brooks joined the Electric Distribution Design Department in 2000, beginning as a Customer Projects Designer. Ms. Brooks spent the first 21 years of her career in that position working with residential, commercial, and governmental customers. In 2021, Ms. Brooks was promoted to her current position as a Customer Contracts Specialist. Her job duties include working with agreements, policies, and terms and conditions.